CPUC Docket: A.21-06-021
Exhibit Number: TURN-09-Atch1
Witness: Garrick Jones

PREPARED TESTIMONY OF GARRICK JONES

ADDRESSING THE PROPOSAL OF PACIFIC GAS AND ELECTRIC COMPANY IN ITS TEST YEAR 2023 GENERAL RATE CASE RELATED TO THE CERTAIN ELECTRIC DISTRIBUTION ISSUES, INCLUDING FOR OVERHEAD INSPECTIONS AND MAINTENANCE, POLE REPLACEMENTS, LBOR REPLACEMENTS, AND SUBSTATION CIRCUIT BREAKER REPLACEMENTS

ATTACHMENTS

Submitted on Behalf of

THE UTILITY REFORM NETWORK

by

Garrick Jones, InfraSMART Energy, LLC

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June 13, 2022

ATTACHMENT 1

QUALIFICATIONS OF GARRICK JONES



Garrick Jones

President, InfraSMART Energy, LLC

Garrick Jones started InfraSMART Energy, LLC in December 2016 as President. Prior to that he was with JBS Energy as an Economist (2007-2016), providing testimony and analytical and research support on a variety of economic, financial and utility operational issues for JBS Energy.

Mr. Jones has filed testimony on various electric and gas distribution operations and maintenance and capital spending issues at the California Public Utilities Commission (CPUC) in the 2011, 2014 20217, and 2020 General Rate Cases (GRC) of Pacific Gas and Electric Company (PG&E), the 2012, 2015, 2018, and 2021 GRCs of Southern California Edison Company and the 2012, 2016, and 2019 GRCs of the two Sempra Energy Utilities. He filed testimony on SCE's marginal costs in its 2012 Phase II proceeding, and marginal cost, cost allocation and rate design in the 2015 and 2021 Phase II proceedings, which all were settled.

He has also testified on smart grid deployment for PG&E, cost allocation for utility funding of Lawrence Livermore National Lab projects, and expected debt and equity returns in nuclear decommissioning triennial applications at the CPUC, on executive compensation before the Public Utilities Commission of Nevada in the 2009 GRC for Southwest Gas Corporation , and before the Arkansas Public Service Commission on rate of return and other revenue requirement issues for Arkansas Oklahoma Gas Company.

Mr. Jones has provided major analytical support for drafting testimony and comments in about 20 additional utility regulatory cases across a number of jurisdictions, including Arkansas, California, Nevada, Texas, and Washington, including the CPUC Electric Vehicle proceedings (R.09-08-009 and R.13-11-007) and PG&E's proposal to purchase a solar-manufacturing development facility (A.10-11-002).

Mr. Jones's experience prior to coming to JBS Energy included environmental analysis and the preparation of environmental impact reports, where his focus and expertise was in energy issues with respect to transit and residential housing projects. Mr. Jones also performed prepared text for a variety of project-related issues, including public utilities and services, hydrology and water quality, and noise pollution. Representative clients for these studies include the California High-Speed Rail Authority, the San Francisco Bay Area Rapid Transit District, the Orange County Transportation Authority, and the City of Orange, California, among others.

Mr. Jones spent two years with the U.S. Peace Corps in Mauritania, West Africa, serving as an Agriculture and Forestry Extension Volunteer. His work included farmer training, the introduction of a regional demonstration farm, and environmental education.

Mr. Jones received his B.S. in Environmental and Resource Science (1998) and M.S. in Agriculture and Resource Economics (2006) from the University of California, Davis.

ATTACHMENT 2

PG&E RESPONSE TO TURN DR 17-1 AND ATTACHMENT 1 AND TURN DR 7-5 AND ATTACHMENT 1 AND ATTACHMENT 2 FROM THE 2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS (WMCE) APPLICATION (A.20-09-019)



PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation and Catastrophic Events
Application 20-09-019
Data Response

PG&E Data Request No.:	TURN_007-Q05		
PG&E File Name:	2020WMCE_DR_TURN_007-Q05		
Request Date:	January 6, 2021	Requester DR No.:	007
Date Sent:	February 10, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Sandra Cullings	Requester:	Marcel Hawiger

SUBJECT: DISTRIBUTION AND SUBSTATION REPLACEMENTS

All Page References are to PG&E testimony unless otherwise specified.

QUESTION 05

Regarding pp. 2-31 to 2-32 (lines 28-2), PG&E states in part

> "the external contractors who completed the majority of the 2019 WSIP replacement work were more expensive than external contractors in prior years."

a. Please estimate the total "increase in cost" for corrective action work in 2019 as a result of the factors identified in the testimony. Please explain, provide calculations in Excel, and include all supporting assumptions.

b. Please quantify as fully as possible how the "external contractors" who completed replacement work "were more expensive than external contractors in prior years." In responding, please provide at a minimum:

   i. Unit costs for contractors in prior years (2015-2018), as compared to unit costs in 2019.

   ii. Any documentation or representative contracts necessary to substantiate.

   iii. The number of external contractors used in each year for overhead replacement work from 2015-2019, in aggregate and converted to FTE equivalents per year.

ANSWER 05

a. Please refer to attachment 2020WMCE_DR_TURN_007_Q5Atch01, which contains calculations illustrating the increase in 2019 costs for corrective action work caused by the increase in the contractor unit cost.

b. PG&E objects to the request as overbroad and unduly burdensome to the extent TURN seeks information beyond the 2017-2019 cost-period at issue in this proceeding. PG&E further objects to the request to the extent it calls for speculation regarding economic conditions impacting contractor pricing. Subject to and without waiving this objection, PG&E responds as follows:

i. Please see attachment 2020WMCE_DR_TURN_007_Q5Atch02, which contains the contractor unit costs for 2017, 2018, and 2019 by MAT code.

ii. Please see attachment 2020WMCE_DR_TURN_007_Q5Atch03, 2020WMCE_DR_TURN_007_Q5Atch04, and 2020WMCE_DR_TURN_007_Q5Atch05CONF which contain a sample contract pricing sheet for 2017, 2018, and 2019, respectively. Please note that for 2019, contracts were priced according to a "daily rate," whereas for 2017 and 2018 contractors were priced according to an agreed upon unit price.

iii. PG&E contractors work on various work streams and work types and are not dedicated to any particular program. Therefore, PG&E cannot provide contractor numbers for the specific replacement work. However, please see the table below which contains the number of contractors, crews, and the average total headcount for all Electric Distribution overhead and underground construction programs in 2017, 2018, and 2019.

	2017	**2018**	**2019[1]**
Number of Contractors	10	13	14
Number of Crews[2] (as of year-end)	59	146	270
Average Total Headcount[3]	236	584	1,080

[1] 2019 counts represent all work performed, including work and associated costs not included in this proceeding

[2] Average crews consist of 4 contractor personnel

[3] PG&E uses both per-unit and time-and-material contracts, and thus does not have the hourly information required to calculate FTEs

MAT	Year	Contract Unit Cost	Units	Total Dollars
07D	2018	$22,133	5690	$ 125,937,895
07D	2019	$54,348	1663	$ 90,380,471
07O	2018	$28,488	33	$ 940,088
07O	2019	$36,495	14	$ 510,931
17B	2018	$11,795	218	$ 2,571,326
17B	2019	$18,132	180	$ 3,263,739
2AA	2018	$8,775	3586	$ 31,466,724
2AA	2019	$12,803	7640	$ 97,818,213
2AB	2018	$3,240	36	$ 116,627
2AB	2019	$19,501	5	$ 97,507
2AF	2018	$5,659	265	$ 1,499,604
2AF	2019	$14,439	37	$ 534,237

**For 2019, units and dollars are reflective of only the incremental work completed for MATs 07D, 07*

Increase in 2019 Cost
$53,572,963
$112,106
$1,140,626
$30,778,121
$81,309
$324,858

'O, 17B, 2AA, 2AB, and 2AF

MAT	Year	Contract Unit Cost
07D	2017	$18,790
07D	2018	$22,133
07D	2019	$54,348
07O	2017	N/A*
07O	2018	$28,488
07O	2019	$36,495
17B	2017	$14,703
17B	2018	$11,795
17B	2019	$18,132
2AA	2017	$7,868
2AA	2018	$8,775
2AA	2019	$12,803
2AB	2017	$5,334
2AB	2018	$3,240
2AB	2019	$19,501
2AF	2017	$16,316
2AF	2018	$5,659
2AF	2019	$14,439

*Footnote

PACIFIC GAS AND ELECTRIC COMPANY
Wildfire Mitigation and Catastrophic Events
Application 20-09-019
Data Response

PG&E Data Request No.:	TURN_017-Q01		
PG&E File Name:	2020WMCE_DR_TURN_017-Q01		
Request Date:	May 5, 2021	Requester DR No.:	017
Date Sent:	May 19, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Sandra Cullings	Requester:	Marcel Hawiger

SUBJECT: PG&E REBUTTAL

QUESTION 01

Re. p. 2-18, lines 7-9:

a. Please provide all SOPs and applicable references to SOPs that discuss the different "accepted duration for a current degraded condition" between the routine historic GO 165 inspection and a WSIP enhanced inspection, respectively.

b. Please explain and provide all documentation, including but not limited to SOPs, that describe how PG&E evaluates whether an asset could degrade in five years.

ANSWER 01

a. Please see attachment 2020WMCE_DR_TURN_017-Q01Atch01, which contains an internal presentation outlining the changes to the GO 165/EC Program for WSIP. The first item in the table on slide 3 compares the previous guidance and new guidance for accepted duration for degraded conditions.

b. Please see attachment 2020WMCE_DR_TURN_017-Q01Atch02, which contains the revised Job Aid for Overhead Inspections, outlining the guidance for assessing compelling abnormal conditions of equipment risk may adversely impact public safety and/or service reliability in the next five years.

Wildfire Safety Inspections Program

Changes to the GO 165/EC Program

Together, Building a Better California

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of future ignitions following the 2018 Camp wildfire

What's Different? Updated Procedures – EC notifications

Based upon the results of the FMEA "Failure Mode and Effects Analysis", **we have made significant changes to guidance on assessing field conditions via GO 165 or WSIP-specific inspections.**

- **Risk-based review approach** resulting in changes to how we identify and prioritize specific field scenarios - including leaning poles, suspect overloaded poles, splices, insulators, floaters, conductor, crossarms, and tree attachments. Additionally, scope of when an EC is written for OH is expanded to issues that needs to be addressed in the next 5 years, vs. 1 year, per previous guidance. *See appendix for detailed list of changes.*

- **Inventory of specific field conditions that exist in Tier 2 and 3 areas** to be analyzed and prioritized for future hardening or reliability projects.

- **Updated OH Inspector job aids** includes new and enhanced guidance for prioritizing specific fire-risk field conditions, including inventory items in Tier 2/3 areas.

- **Adjusted prioritization of specific FDAs (Facility/Damage/Action)** to align with risk-based approach, i.e. several work types moved from "regulatory" Priority F to maximum Priority E.

- **Additional Centralized Gatekeepers have been added** to account for increase in EC create rate to ensure timely/quality review of incoming non-emergency ECs.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of future ignitions following the 2017 and 2018 Camp wildfires 11

Internal

What's Different – Updated Procedures – GO 165 Program

GO 165 / EC Program Changes: Refer to revised OH Job Aid TD-2305M-JA02, Rev. 5.8, Mar. 2019

Facility Type	Previous Guidance	New Guidance
All Overhead	Write EC for Regulatory Issues (high signs, etc.) and compelling conditions that need to be addressed in the next 12 months	Write EC for Regulatory Issues (high signs, etc.) and compelling conditions that need to be addressed in the next 5 Years
Conductor	Visually check all primary, secondary, and service conductors for excessive sag, broken/damaged, frayed, cracked, strain/abrasion. Write EC if conductor issues needs to be addressed in the next 12 months. Refer to conductor clearance job aid for all clearance requirements. If Inspector suspects clearance issue, write EC if clearance standard is not met.	Write EC notification to replace ALL insulink and mini-wedges or any improperly used secondary connectors used in primary. Inspect all connections; write EC notification to replace all connectors with dissimilar metals that are incorrectly installed (copper over aluminum is incorrect). Visually check all auto-splices in a span. Write EC notification for automatic splices that appear to be damaged, corroded or tied in too close to the insulator, preventing free movement of the splice with the conductor Write EC notification for any spans with uneven conductor. Write EC notification to replace annealed copper conductor (6 or 4 solid). For all open wire secondary/rack construction, identify missing spreaders for >135 ft span; for spans that are longer, install spreader brackets every 135' when possible, otherwise, write EC notification to have spreader brackets installed where bucket truck accessible. If no access, write EC to have the vegetation cleared.
Crossarms	During detailed inspections, examine wood cross arms and assess their condition for all compelling abnormal conditions; write EC if crossarm needs to be addressed in the next 12 months.	During detailed inspections, examine wood cross arms and assess their condition for all compelling abnormal conditions; write EC if crossarm needs to be addressed in the next 5 years.
	No previous guidance to replace wood crossarm with composite.	Wood crossarms to be replaced with composite crossarm and associated hardware by construction crew completing the EC notification.
Floaters	Identify floaters; assess to determine priority (A, B, or E).	Floaters are ALWAYS emergency; stand-by required.
Insulators	Write EC to replace broken/damaged, chipped, cracked, flashed/burnt insulators that need to be addressed in the next 12 months.	ANY chipped, cracked, contaminated, broken, or damaged insulator to be replaced; cannot mix insulator types. Always replace full set of insulators AND replace crossarm w/composite crossarm. If gunshot - epoxy of polymer insulators. Write EC to replace **ALL** LAPP Insulators (based on guidance - specific installation year in the field). ANY chipped, cracked, contaminated, broken, or damaged insulator to be replaced; cannot mix insulator types. Always replace full set of insulators AND replace crossarm w/composite crossarm.
	Identify all primary squatters, at minimum priority F/5 years.	Primary squatter ECs now required to be max priority E, 12 month duration.

Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of future ignitions following the 2017 and 2018 Camp wildfires 12

What's Different – Updated Procedures (cont'd)

Facility Type	Previous Guidance	New Guidance
Poles	Write a Third Party notification for PG&E solely owned poles with third party attachments if the other utility's facilities are causing a safety issue.	Identify all solely owned pole with third-party attachments (based on how it is mapped). Write EC Notification for Pole / Overloaded / Test, for Estimating to confirm pole loading.
	General Guidance: Assess pole to determine if pole needs to be addressed (adjusted/replaced) in the next 12 months.	For ANY reduced circumference identified on a pole, at minimum, write EC for Pole / Overloaded / Test, for Estimating to confirm pole loading.
	Consider the following when evaluation a leaning pole: 1. Is the pole out of plumb by more than 10% of its height above the ground? 2. Is the leaning pole causing excessive conductor sag? 3. Does the lean appear as if it will become worse or affect safety or reliability in the next 12 months (considering environmental and configuration factors -soil, wind, pole attachments, equipment, guying)? If the answer is yes to any of these questions, *and in the inspector's judgment the pole is leaning excessively*, write an EC Form and fill out Pole Test Data Sheet.	Consider the following when evaluating a leaning pole: 1. Is the pole out of plumb by more than 10% of its height above the ground? 2. Is the leaning pole causing excessive conductor sag or reduced clearance issues that could result in contact, fire risk, or public safety? 3. Does the lean appear as if it will become worse or affect safety or reliability in the next 5 years (considering environmental and configuration factors -soil, wind, pole attachments, equipment, guying)? If the answer is yes to any of these questions write an EC Notification (Pole /Overloaded /Test) and fill out Pole Test Data Sheet. **All poles need to be load calculated prior to straightening.**
	IF the pole is excessively deformed (bowing, bending, improper guying, no guying); THEN create an EC Form. . IF the pole is excessively deformed (bowing, bending, overloaded) due to communications; THEN create a Third-Party Utility Form.	For deformed poles, write EC Notification for Pole / Overloaded / Test, for estimating to confirm pole loading. If the deformity appears as if it will become worse or affect safety or reliability in the next 5 years (considering environmental and configuration factors -soil, wind, pole attachments, equipment, guying) - write EC notice to replace pole. Common drivers for deformed poles: Improper/lack of guying, third party attachment Review clearances to verify no reduced clearance issues, all levels of clearance requirements that could result in contact, fire risk, or public safety.
Transformer	OH Transformer with signs of dried oil or stain only: Per oil spill matrix, no action required for this scenario in the field.	If an Inspector is writing an EC to address an issue at a pole location, and there is a transformer with oil stain ONLY (no action per oil spill matrix), add transformer to EC to be replaced.
Tree Attachment	Identify dead/dying trees.	If there are any questions about the integrity of tree, (causing damage to our facilities, dead or dying, causing conductor height issue, etc.), write vegetation EC to remove dead dying trees.

What's Different – Updated Procedures (cont'd)

GO 165, Tier 2/3 Inventory Items		
Animal Activity	**No previous guidance or requirement to inventory any condition during GO 165 inspect or patrol.**	Record locations with any evidence of animal activity, nesting, damage or debris associated with the pole
Animal Guards		Record all locations with missing animal guards on all overhead transformers. Document locations that do not have bushing covers and insulated jumpers.
Bridging		Record all locations where bridging is absent.
Chance Clamps		Record improperly installed Chance Clamps associated with the pole. (Guidance: Identify improperly installed chance clamps (no armor rod under chance clamp for conductor smaller than 1/0 or installed incorrectly on tap line supporting more than 2 TXs or used on any other type of equipment
Conductor		1. Record all open wire locations 2. Record number of auto splices in a span 3. Record all Kierneys and PGs
Cutouts		Record all locations with bushing-mounted cutouts.
Flying Bells		Record all locations with flying bells installed on primary.
Insulators		Record every location where flying bells are installed. Identify type of insulator, ceramic or non-ceramic.
Non-Exempt Equipment		Record any Non-Exempt Fuse Cutouts and/or Switches associated with the pole. (Guidance: Look for equipment without snuffing capabilities; expulsion type of fuse; Lightning Arrestors, Switches with no LB's - KPF's, Grasshopper, Porcelain In-line Disconnects; Non-exempt cutouts may eject material.)
Oil-Filled Equipment		Record all locations with oil filled equipment on pole.
Tree Attachment		Record All tree connects - secondary, service, guying.

ATTACHMENT 3

EXCERPT OF EXHIBIT 3, CHAPTER 2 WORKPAPERS FROM 2011 GRC ("UTILITY OPERATIONS STANDARD S2301")



Application: _____
(U 39 M)
Exhibit No.: (PG&E-3)
Date: December 21, 2009
Witness: Various

PACIFIC GAS AND ELECTRIC COMPANY

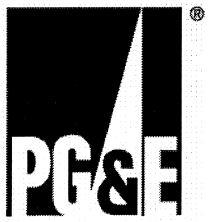
2011 GENERAL RATE CASE

EXHIBIT (PG&E-3)
GAS AND ELECTRIC DISTRIBUTION

WORKPAPERS SUPPORTING

CHAPTERS 1, 2, 3, 4 AND 5

VOLUME 1 OF 3



PACIFIC GAS AND ELECTRIC COMPANY
GAS AND ELECTRIC DISTRIBUTION

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5	VEGETATION MANAGEMENT	Daran M. Santi

PACIFIC GAS AND ELECTRIC COMPANY
2011 GENERAL RATE CASE
Exhibit (PG&E-3), GAS AND ELECTRIC DISTRIBUTION COSTS

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Kevin J Dasso
Kevin Dasso
12/12/09
Date

Pacific Gas and Electric Company	UTILITY OPERATIONS (UO)
	UO Standard S2301
ISSUING DEPARTMENT: Electric T&D Engineering	EFFECTIVE DATE: 1-06
UO SPONSOR: Senior Director - E&P	REVIEW DATE: 1-11
	PAGE NO.: 1 OF 8

TITLE: Electric Distribution Preventive Maintenance (EDPM) Program for Overhead and Underground Facilities

Purpose

This UO standard establishes the Electric Distribution Preventive Maintenance (EDPM) program and describes the roles, responsibilities, and requirements of the preventive maintenance program. The key elements of this program include detailed and infrared inspections, equipment testing, patrols, and routine maintenance of overhead and underground electric distribution facilities.

The requirements in this *standard* support UO Policy 3-7, "Gas and Electric Operation, Maintenance, and Construction," and are focused on identifying specific abnormal conditions that affect safety, reliability, and asset life of the electric distribution facilities. The EDPM program does not necessarily specifically identify nonconformance to Company standards. Identifying any nonconformance items is accomplished by following construction or reconstruction activities (design and build the facilities per the standards).

Recision

This standard **supersedes** the following documents:

- **UO Standard S2301**, "Electric Distribution Preventive Maintenance (EDPM) Program for Overhead and Underground Facilities," effective 4-03.
- The electric distribution maintenance program requirements of UO Standard S2301 have been removed from the 2005 *EDPM Manual*. The 2006 *EDPM Manual* identifies the process supporting the patrol, inspection, assessment, notification, and record retention of the program.

Safety

This standard complies with Utility Standard Practice (USP) 22, "Safety and Health Program," and the *Code of Safe Practices*.

Personal and public safety can be time-consuming, difficult, and involved, but shall never be compromised.

- Corrosion with noticeable metal damage.
- Noticeable leaking or weeping oil.

Abnormal conditions identified by the patrol must be documented.

2. Detailed Inspection Requirements

Inspections were developed as a key element in this preventive maintenance program to reduce the potential for component failures and further facility damage, and to facilitate a proactive approach to repairing or replacing identified abnormal components. Inspected facilities include overhead and underground primary, secondary, service, and other associated electric distribution facilities outside the substation fence to the end of line. Overhead inspections include an external visual evaluation of the overhead facilities. Underground inspections include a visual evaluation of the exterior and interior of the underground primary enclosure, and an exterior visual evaluation of other visible underground substructures. An underground inspection is typically from the location of underground facilities at a primary riser to the end of those underground facilities, or the end of the underground line, and will include an evaluation for facility accessibility.

The primary responsibility when inspecting an overhead or underground electric facility is to examine, prioritize, and record any abnormal conditions (by assigning a grade and duration) to the facilities being inspected. The inspection requires an extensive evaluation (e.g., visual observation, which could include using measuring devices or tools) to determine if there are any abnormal structural problems or hazards that will adversely impact safety, service reliability, or asset life, and to evaluate when each identified abnormal condition warrants maintenance. An inspection requires the ability to view all sides of the facilities (including line equipment). When evaluating line equipment, a visual inspection to check the condition of the bushings, tank, bypass, disconnect switches, control cabinets, lightning arrestors, etc., is required. Abnormal conditions that will adversely impact safety, service reliability, or asset life, and require maintenance before the next inspection cycle, must be appropriately documented.

A. Overhead Inspection Cycle

Overhead distribution facilities shall be inspected on a 5-year cycle. Schedules shall be established such that facilities will be inspected at least once every fifth calendar year. In any given year (in terms of years), the facilities inspected should be those facilities with the oldest prior yearly inspection cycle.

An infrared inspection must not be considered as, or substituted for, an overhead detailed inspection.

B. Underground Inspection Cycle

Underground distribution facilities shall be inspected on a 3-year cycle. Schedules shall be established such that facilities will be inspected at least once every third calendar year. All underground conductors and splices within primary enclosures must be inspected. In any given year (in terms of years), the facilities inspected should be those facilities with the oldest prior yearly inspection cycle.

Infrared inspections must not be considered as, or substituted for, an underground inspection.

ATTACHMENT 4

PG&E INDEPENDENT MONITOR REPORT OF NOVEMBER 19, 2021



KIRKLAND & ELLIS LLP

PG&E Independent Monitor Report of November 19, 2021

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I. INTRODUCTION

A. Factual Background

On September 9, 2010 PG&E's 30-inch gas transmission line in San Bruno ruptured, exploded, and burned uncontrollably for hours while PG&E employees attempted to shut off the gas. The explosion destroyed the Crestmoor neighborhood in San Bruno and killed eight people: Lavonne Bullis, 82; Greg Bullis, 50; William Bullis, 17; James Franco, 58; Jacqueline Greig, 44; Janessa Greig, 13; Jessica Morales, 20; and Elizabeth Torres, 81.

Six years later, PG&E was found guilty by a federal jury after a multi-week trial of six felony violations. These included various felony violations related to Gas Operations recordkeeping and another felony violation for obstruction of justice concerning a National Transportation Safety Board investigation of gas pipeline testing. The guilty verdict resulted in the imposition of a federal monitor and the creation of this Monitorship in 2017. The initial foci of the Monitorship, as set forth in a January 26, 2017 judgment and Court order (Dkt. 916), were: (1) 15 technical requirements related to PG&E's Gas Operations; (2) PG&E's Compliance and Ethics program; and (3) PG&E's efforts to become a safer utility. Those areas are discussed below at Sections III-V.

The Monitorship proceeded along those lines from 2017 to 2018. In late 2018 and early 2019, the Court expanded the scope of the Monitorship to include an assessment of PG&E's wildfire mitigation efforts following the 22 deaths and destruction caused by PG&E in the 2017 Northern California wildfires (including the Wine Country Fires and the North Country Fires), as well as the Camp Fire of 2018, in which 84 people were killed and the city of Paradise in Butte County was destroyed. Including the Camp Fire fatalities, over 110 people have died as a result of wildfires where CAL FIRE has determined PG&E equipment was involved since the San Bruno incident.[1]

[1] During the course of the Monitorship, the Monitor team did not investigate or make any determinations about the cause and origin of fires. Those issues were the province of many other authorities, including regulators and law enforcement agencies which took possession of certain evidence and sometimes initiated prosecutions, and numerous

Appended as Exhibit 1 is a list of the victims of those wildfires.

The Court's oversight of PG&E's wildfire mitigation efforts substantially augmented the scope of the January 2017 order. Since that time, the Monitor team's evaluation of PG&E's wildfire mitigation efforts has focused on four core areas: (1) vegetation management ("VM"); (2) infrastructure inspections and repairs; (3) system hardening; and (4) emergency preparedness and response. Those areas are discussed in Sections VII-X below.

PG&E wildfire mitigation efforts the past few years have been insufficient to stop wildfires caused by PG&E equipment. Each year since 2017, PG&E equipment has been associated with at least one catastrophic wildfire. That is obviously unacceptable, and PG&E must improve and fix this situation.

B. Overarching Themes

As explained below, PG&E has demonstrated progress within the scope of the Monitorship, and sometimes substantial progress. Regarding Gas Operations, PG&E's reform and improvement work, some of which began after San Bruno and before the Monitorship started, has been sustained and substantial. There has also been sustained and substantial improvement in the Compliance and Ethics area, although the Company needs to continue to try to overcome worker skepticism, particularly among longer-tenured employees, that the Company does not want to hear bad news and will retaliate for it, and that PG&E admonitions to "Speak Up" are not sincere.

Progress regarding wildfire mitigation obviously has been inadequate, and we doubt anyone would seriously dispute that, given the ongoing and profound safety issues in that area of operations.

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civil litigants and their attorneys with their own due process rights to present their own claims. The numbers here of deaths caused by PG&E come from data such as PG&E's 84 guilty pleas in June 2020 to involuntary manslaughter in connection with the Camp Fire and deaths, as well as CAL FIRE determinations on cause and origin of fires.

Nothing in this report purports to assert a factual finding or evidence concerning any pending or future litigation. These observations are intended to be candid comments based on our work as a Monitor team, but we did not conduct that work in a manner structured by state or federal adjudicatory rules or process.

As we have documented in prior Court filings, PG&E's initial steps in the wake of recent catastrophic fires were not planned and executed well. However, some of the key leaders who drove improvements in Gas Operations are now working on wildfire efforts, and hopefully they can drive similar positive change going forward.

We relate progress and issues in the various operational areas below. We also will discuss the six most salient challenges PG&E faces going forward, which are:

1. Retaining a core leadership team, in the wake of near constant turnover in recent years. During the four-and-a-half year Monitorship period alone, the Company has had five CEOs, six heads of Gas Operations, four heads of Electric Operations, and five heads of the Safety organization. Multiple other senior officers have otherwise turned over. PG&E also has had no less than 45 different board members during that time.

2. Continuing to improve records integrity, which has been an issue for PG&E for many years and remains a central challenge.

3. Continuing to improve contractor management, because contractors are a critical workforce base, including on the wildfire mitigation front.

4. Adhering to commitments to invest in long-term safety projects, including undergrounding efforts for electrical distribution lines and the repair and replacement of at-risk electrical equipment, and sustaining completion dates and not letting them slide.

5. Improving planning and execution of wildfire mitigation efforts.

6. Ensuring the employment of resources to improve wildfire safety does not result in cannibalization of gas safety teams and results that have been achieved during recent years.

II. SAFETY OBSERVATIONS

Safety observations are presented in roughly chronological order by subject matter. That is, the topics that were the subject of the original Monitorship are presented first. Newer subjects that were added by the Court in the aftermath of the Camp Fire and thereafter are presented second. Then observations of ongoing challenges are discussed.

Before proceeding, we wish to acknowledge the assistance and cooperation of several relevant parties during the period of the Monitorship. These include present and former government officials in San Bruno; family members of those killed in the San Bruno tragedy; federal law

enforcement officials, including agents, task force officers, and federal prosecutors; PG&E's United States Probation Officer; local officials in Paradise; and leaders and employees at PG&E, as well as its outside counsel on the Monitorship, Jenner & Block. The issues that arose under this Monitorship were and remain profound. There were many serious and extended discussions about progress or the lack thereof. During that entire period of time, we were met with professional and honest input from all of the persons listed above. We also wish to thank the external experts who assisted the Monitor team. They are some of the best safety experts in their respective fields, and we are grateful for their contributions.

III. GAS OPERATIONS

A. Introduction

This Monitorship was the result of PG&E's 2016 jury conviction in the U.S. District Court for the Northern District of California. That prosecution took place in the wake of the San Bruno gas explosion, which killed eight people, injured 58 more, and destroyed many peoples' homes. As a result, the original scope of the Monitorship naturally centered on PG&E's Gas Operations and ethics and integrity functions. Wildfire issues were not part of that scope.

After the Monitorship was established, we met with family members of some of the victims of the San Bruno explosion. The overwhelming message from them was they hoped the San Bruno tragedy would spur meaningful reform and change in PG&E's Gas Operations, so that no one would again suffer the losses that their loved ones and they had experienced.

The tragic deaths of the San Bruno victims and the federal prosecution have led to substantial progress in PG&E's Gas Operations since 2010. Since that time, there have been no customer fatalities or injuries caused by gas pipeline explosions, and as explained below, the Compliance and Ethics functions at the Company have improved. Measured within the confines of the original

Monitorship, the reforms and improvements in Gas Operations and ethics have been real and significant.

B. The 15 Technical Requirements

A substantial focus of the Monitorship as framed in the wake of the 2016 federal trial concerned 15 technical requirements designed to promote safer Gas Operations. PG&E has successfully completed several of these requirements, including some long ago. The other requirements are not of the nature that they are ever "completed," but rather focus on certain important safety practices that always admit of continuous improvement. As to these requirements, PG&E also has made substantial progress and is positioned to make more with sustained focus and effort. The challenge will be to maintain that focus, commitment of resources and talent, and continuous improvement once federal probation ends.

C. Progress Across the 15 Technical Requirements

Each of the 15 technical requirements is discussed here. The full list of technical requirements as set forth in the judgment is provided in Exhibit 2.

Requirement One focuses on PG&E's self-reporting system in Gas Operations. California Public Utilities Commission ("CPUC") regulations require PG&E to evaluate and self-report potential violations that it identifies. The Monitor team believes that PG&E's self-reporting system satisfies Requirement One. The self-report program includes appropriate information for evaluations, including submissions to the Corrective Action Program, employee notifications, internal and external audits, and submissions to PG&E's ethics hotline. The self-report team evaluates between six and twelve potential self-reports each week, and the evaluations are typically thorough and complete. Participants in self-report meetings include engineers, regulatory personnel, internal legal counsel, and other relevant stakeholders. Subject matter experts are engaged and consulted as necessary for technical issues. The self-report team's recommendations regarding self-

report letters, other notification to the Safety Enforcement Division, or "no notification" determinations are accepted by Gas Operations and not overturned or second-guessed. Regulatory Compliance personnel handle disposition of regulatory safety citations effectively and with appropriate priority and urgency.

Requirement Two is focused on PG&E's traceable, verifiable, and complete ("TVC") records supporting the Maximum Allowable Operating Pressure ("MAOP") of its transmission pipeline. PG&E initiated work in this area in advance of the start of the Monitorship, implementing multiple quality control and assurance steps. The Monitor team believes PG&E's efforts have been reasonable and consistent with the goal of identifying TVC records for MAOP validation. The NTSB also found PG&E's efforts to identify TVC records satisfactory and, on March 14, 2013, it issued a "Closed—Acceptable Action" letter for Urgent Action P-10-03.

Requirement Three sets forth a goal of strength testing at least 500 miles of gas transmission pipeline in 2017 and 2018. Requirement Three was closed out in early 2019 after the Monitor team confirmed that PG&E properly strength tested 540 miles of its transmission pipeline: 253 miles in 2017 and 287 miles in 2018. The Monitor team attended several of the strength tests and reviewed the results to confirm the accuracy of PG&E's mileage calculations. The Monitor team and our experts are also satisfied that PG&E properly utilizes strength testing as an ongoing integrity management tool for its transmission pipeline.

Requirement Four required upgrading and/or retrofitting 300 miles of gas transmission pipeline to accommodate in-line inspection tools in 2017 and 2018. As with Requirement Three, this requirement was closed out in early 2019 after the Monitor team confirmed that PG&E upgraded 397 miles of transmission pipeline: 154 miles in 2017 and 243 miles in 2018. The Monitor team and our experts inspected several upgrade projects in 2017 and 2018, evaluated project as-builts, and met with PG&E specialists to confirm scope of work completed.

Requirement Five focuses on data gaps in PG&E's transmission pipeline records and requires PG&E to make conservative, supportable assumptions when TVC data are not available. Prior to the Monitorship, PG&E had developed and implemented initial policies to address this requirement, including issuing the Procedure for Resolution of Unknown Pipeline Features ("PRUPF"). PRUPF is PG&E's guidance document concerning the use of conservative, supportable assumptions and includes mandatory assumptions for unknown specifications based on subject matter expert judgments and industry data. PG&E reviews PRUPF on an annual basis to determine if revisions are needed. The Monitor team believes PRUPF sets forth a conservative approach for missing data and that PG&E has satisfied Requirement Five.

Requirement Six requires PG&E to collect and incorporate leak data in one database for use in gas pipeline integrity management. PG&E has made progress to satisfy this requirement and adequately incorporates transmission pipe leak data into its database of record. PG&E currently holds monthly leak review meetings where members of the Transmission Integrity Management Program ("TIMP") group meet to evaluate transmission line leaks. While progress has been made, at its core, this is a records issue that needs continual effort and work. PG&E should enhance this process to reduce the need for a manual evaluation by improving its digital records and automating the incorporation of transmission leaks directly into its database of record.

Requirement Seven focuses on PG&E's efforts to ensure that it is collecting adequate and quality data as inputs for its Gas Transmission Integrity Management Program. Over the course of the Monitorship, the Monitor team evaluated PG&E's data gathering, collection, and review processes across relevant gas data sources for its Integrity Management Program. At this time, the Monitor team believes that those efforts substantially meet the requirements of 49 C.F.R. Part 192.917(b) and ASME B31.8S. The Monitor team concluded that PG&E properly identifies the individual data elements required for its threat and risk modeling work, and PG&E has conducted

gap analyses to inform its remediation of observed deficits in its data gathering requirements. PG&E's Gas Operations models appropriately identify the necessary data and the organization is focused on improving the data inputs for those elements. This is a "continuous improvement" area, and it merits sustained focus because of its impact on gas pipeline safety.

Requirement Eight required PG&E to develop and update an Integrity Management Program that is "effectively assessing and evaluating the integrity of each covered segment" of gas transmission pipeline. The Monitor team believes that PG&E has an appropriate Integrity Management transmission risk model for Gas Operations which satisfies the requirements of ASME B31.8S and meets NTSB recommendation P-11-29. The risk model is comprehensive and properly incorporates data consistent with ASME B31.8S.

Additionally, the Monitor team has seen improvement in the annual update cycle for the risk model each year. In the 2018 annual model update cycle, the Monitor team observed process deficiencies and a lack of rigor in PG&E discussions and analyses and we raised our concerns with the TIMP organization. In 2019, TIMP made substantial improvements to the process and those have been maintained and developed in each of the past two update cycles, through 2021. The TIMP program is on the right course, particularly with the implementation of its recently issued five-year roadmap for the risk model's development. This is a "continuous improvement" area, and it merits sustained focus because of its impact on gas pipeline safety.

Requirement Nine focuses on PG&E's efforts to reclaim and maintain its right of way over its gas transmission pipeline. As with some other requirements, PG&E implemented procedural reforms related to encroachments even prior to the Monitorship. Currently, PG&E has not yet completed its remediation of encroachments identified as part of the 2010 centerline survey, although the gap is modest and the function of forces beyond PG&E's control. More specifically, as of June 2021, 99% of legacy structural and vegetative encroachments have been removed and

there are 9.28 miles of vegetative encroachments (out of 1,544 miles initially identified) and eight structural encroachments (out of 2,613 initially identified structures) remaining. In the remaining instances, corrective measures have been delayed by litigation or municipalities blocking the work. Nonetheless, the Company plans to address the remaining structural encroachments by the end of 2021 and to remove the remaining vegetation by the end of 2022.

In addition to remediating legacy encroachments, PG&E's ongoing program to ensure that no new encroachments occur is appropriate. Employees conduct annual patrols, and PG&E leverages its aviation technology to assess the centerline and any potential encroachments.

Requirement Ten focuses on PG&E's assessment and evaluation of stress corrosion cracking in its gas transmission pipeline. The Monitor team and our experts have reviewed PG&E's Stress Corrosion Cracking ("SCC") threat assessment model and analysis and concluded that PG&E properly identifies, evaluates, and addresses the SCC threat. Additionally, the Monitor team assessed four gas transmission pipeline segments that had SCC-related leaks and found that PG&E's procedures properly account for risks on those segments.

Requirement Eleven requires PG&E to implement procedures to ensure that relevant data are incorporated into gas threat identification and assessment procedures. PG&E's threat logic and assessment procedures appropriately consider relevant data for purposes of identifying threats recognized pursuant to applicable regulations and standards. In the past year, under new leadership within TIMP, PG&E has undertaken an effort to improve the accuracy and stability of its threat identification logic to better reflect real-world mileage subject to various threats, which was a necessary improvement. The new initiative aims to align threat identification and field assessments to calibrate PG&E's Integrity Management Program with real-world risk. The new initiative reflects a focus on continual improvement of data, records, and risk modeling in Gas Operations, which must continue in the future.

Requirement Twelve focuses on PG&E's efforts to identify High Consequence Areas ("HCAs") across its gas system. Since San Bruno, PG&E has developed a thorough process for identifying class locations, HCAs, and, under the new federal PHMSA Mega-Rule, Medium Consequence Areas ("MCAs"). PG&E reported in its 2020 HCA study that there were a total of 1,593 miles of HCAs and 821.3 miles of MCAs, which will help in risk assessment and oversight prioritization. In 2020, an additional 1,985 pipeline sections (totaling 19.02 miles) were added to HCAs, and 24 pipeline sections (totaling 0.32 miles) were de-designated as HCAs. The Monitor team and our experts assessed two pipeline segments for which the HCA designation was removed, and we are comfortable with PG&E's decisions.

PG&E has taken several steps to improve its HCA and MCA determination processes such as using enhanced structures databases. This is the sort of continual improvement that PG&E must sustain and that the people of California should expect.

Requirement Thirteen focuses on PG&E's ability to incorporate changed circumstances into its risk planning, consistent with ASME B31.8S. The Monitor team believes that PG&E has satisfied this requirement, although there is opportunity for continued progress. Over the course of the Monitorship, the Monitor team has seen improvements in PG&E's efforts and ability to incorporate changed circumstances. Within TIMP there is now a dedicated Continual Evaluation ("CE") Group specifically tasked with this function. The CE Group evaluates Company and industry trends and is conducting longer-term pilot projects to calibrate threat models with field data (for example, third-party damage) through machine learning applications. These are examples of positive, continual improvement under this requirement.

Requirement Fourteen focused on ensuring that PG&E ceased its ill-advised legacy practice of raising pressure in its pipeline to the perceived maximum allowable pressure to re-establish "system MAOP." This requirement was successfully completed. The Monitor team and

our experts verified PG&E's representations that it had ceased this practice shortly after the San Bruno tragedy through an independent audit of pressure data in various PG&E pipelines. There was no indication in any of the reviewed data that any planned pressure increases were taking place. Additionally, the Monitor team verified that any pipeline traditionally put through the "planned pressure increase" program to establish system MAOP had been assessed through: (a) strength testing, (b) replacement, or (c) down-rating of applicable operating pressure.

Requirement Fifteen focuses on proper calculation of cyclic fatigue and fatigue life of the gas pipeline system. The Monitor team and our experts believe PG&E's methodology for calculating fatigue life, which was designed and implemented by external consultants, is consistent with and more conservative than industry standards, which enhances the safety of PG&E's gas transmission system. The Monitor team collected data for 11 pipeline segments and performed an independent fatigue life calculation in accordance with industry standards. This data and analysis supports the Monitor team's conclusion that the cyclic fatigue calculation methodologies employed are consistent with and more conservative than industry standards.

D. Gas Operations Challenges

While Gas Operations has done a good job in focusing on the technical requirements and making progress against those targets, it has faced challenges as well. These episodes reflect the need for continued vigilance. Our hope is that the efforts to work together through the issues discussed below and others have enhanced the capacity of PG&E Gas Operations to successfully confront similar issues alone in the future.

For instance, there was a rise in overpressure events in 2019 and through mid-year 2020. Overpressure events, even small ones, are significant issues, and because the numbers were above PG&E's targets and the trend was moving in the wrong direction, the Monitor team flagged the issue in the fall of 2020. At that time, there was an Overpressure Elimination Program ("OEP")

with a goal of changing training and workflow by the spring of 2021. Because 2020 had already seen nine large overpressure events (defined by PG&E as an exceedance more than 10% beyond MAOP), that timeline required more urgency and we notified and engaged with senior management in Gas leadership to secure that commitment. Once senior Gas leadership became directly involved, that timeline quickly accelerated and the OEP rolled out additional training earlier, worked on identifying root causes and root cause trends across the overpressure events, and continued work on pipeline design changes. So far, 2021 has seen a reduced number of large overpressure events and, when they do occur, cause evaluations are conducted promptly and lessons learned are distributed quickly. Overall, this is a positive story.

As another example, over the summer and fall of 2018, PG&E personnel reviewed all leak cancellation notifications entered from January 1, 2014 through August 1, 2018 because of a concern that leak notifications that had been improperly canceled (for example, cancelled without documentation supporting a conclusion that a leak was no longer emitting pipeline gas). Given the uncertainty regarding the leak records, the Company expeditiously re-inspected approximately 47,600 canceled leak notifications. Coming out of this process, in Q4 2018, PG&E created a working group to assess its leak survey and closure process, and thereby to identify opportunities for improvement across all leak survey work and leak survey tools.

One of the instructions coming out of this working group was that a "Leak Cancellation Desk" should be established. Although efforts were made within PG&E's Leak Survey group to establish the Leak Cancellation Desk, these efforts foundered such that, by the summer of 2019, the Leak Cancellation Desk still had not been created. Because it failed to timely establish the Leak Cancellation Desk, PG&E again had to conduct a re-review and re-survey process for approximately 8,000 canceled leak notifications, this time for the period between September 1, 2018 and June 30,

2019. After the second re-review project, the Leak Cancellation Desk was actually established, it has been refined over time, and its work continues today.

Overall, the recent history of reform and improvement in Gas Operations is positive. There are two main risk factors to this improvement. The first is the risk of complacency—of assuming that things will remain good when, in fact, every day requires constant vigilance. The second risk is that the people who drove much of the reform and improvement in Gas Operations (including the current Chief Risk Officer, Sumeet Singh) have often been moved to wildfire issues related to Electric Operations. This is to some degree inevitable and prudent given recent lethal problems and issues with wildfires. However, thoughtful analyses and assessments must be made as to when additional resources are needed overall, including in Gas Operations, to prevent cannibalization of the efforts to drive progress in Gas Operations since San Bruno.

IV. COMPLIANCE AND ETHICS

In addition to the 15 individual requirements, the Monitor team was tasked by the January 26, 2017 Court order "to assure PG&E's compliance with the goals outlined in the United States Sentencing Guidelines Section 8B2.1: Effective Compliance and Ethics Program." (Dkt. 916). The Federal Sentencing Guidelines require measures to prevent, detect, and address criminal misconduct and to promote an organizational culture that encourages ethical conduct and a commitment to compliance with the law. U.S. Sentencing Guidelines Manual § 8B2.1 (2021). Such a compliance and ethics program "shall be reasonably designed, implemented, and enforced so that the program is generally effective in preventing and detecting criminal conduct." *Id.* § 8B2.1(a). The Monitor team believes that PG&E's Compliance and Ethics ("C&E") program is consistent now with these requirements.

PG&E's central C&E department promotes legal compliance and ethical behavior, guides Lines of Business ("LOBs") in implementing PG&E's C&E agendas, and reports on C&E

performance. During the course of the Monitorship, and under the leadership of people like Julie Kane, John Simon, and Alex Vallejo, PG&E has established an appropriate governance structure to foster communications with the LOBs. PG&E's C&E-related governing bodies and senior leaders, including its Board of Directors and Compliance and Public Policy Committee at the Board-level, and its Compliance, Ethics, and Audit Committee at the operational level, are engaged in understanding and providing oversight and guidance for PG&E's C&E program. Monthly joint Compliance and Ethics Leadership Team ("CELT") and Compliance Liaisons meetings, focused on day-to-day implementation of C&E strategies, provide an efficient means for discussing and shaping the C&E agenda and coordinating among C&E stakeholders. PG&E should continue to make conversations between LOB leaders and their designated C&E professionals a regular feature of the LOBs' C&E activities to ensure adequate messaging and alignment and to help PG&E's C&E program gain traction in the field. Such direct coordination with and support from senior leadership are essential to empowering CELT members and Liaisons to effectively execute on and drive PG&E's C&E agenda, including into the broader workforce.

PG&E's C&E programs and practices are guided by and assessed under a compliance "Maturity Model." The Maturity Model establishes a C&E framework with eight elements based on the Federal Sentencing Guidelines. The C&E team has also developed an oversight model for PG&E's top 35 compliance risks, assigning each to one of four levels of central C&E oversight. PG&E's recent shift to risk-informed compliance work is consistent with heightened focus on such an approach by PG&E's regulators. While adapting to regulatory trends and changing circumstances is appropriate and consistent with the DOJ's emphasis on having an evolving and tailored C&E program, PG&E should ensure that its new approach includes sufficiently objective, systematic oversight of PG&E's C&E performance.

Promoting a compliant and ethical culture, particularly through PG&E's "Speak Up, Listen Up, Follow Up" initiative, has been an appropriate and central focus for the C&E team throughout the Monitorship. One highlight of efforts is PG&E's roughly 80-member Ethics Council, comprised of employees from all levels of PG&E— including critically, field personnel—which meets monthly with the goal of promoting a culture that embraces and advances ethical behavior in PG&E's operations and employee relationships. These meetings provide an important opportunity for employees across the organization to have frank discussions about C&E issues with senior leaders, and PG&E should continue to promote such openness. Although the Company continues to face impediments to a culture of speaking up, including employee fear of retaliation, the Monitor team believes PG&E is committed to and making meaningful strides toward effecting culture change.

The Monitor team encourages PG&E's C&E leaders to continue to amplify and drive forward PG&E's core C&E agenda and messages to make clear that they are enduring and that the Company is committed to their effective implementation. It is imperative that PG&E work assiduously to earn the trust of its workforce, who (especially among longer-serving PG&E personnel) often doubt whether their managers and supervisors actually want to hear bad news. This commitment also includes ensuring that PG&E's C&E program is resourced and empowered to function effectively and that PG&E has objective, systematic means for ensuring accountability and assessing and monitoring its C&E program and performance. New and unexpected challenges will continue to arise. PG&E's C&E program must be adequately resourced and cultivated to withstand those challenges.

V. SAFETY AT PG&E

At the outset of the Monitorship, it is likely that nobody anticipated the scope of the Company's profound public safety issues, with more than 110 PG&E customers killed in recent years due to wildfires associated with PG&E equipment. PG&E needs to take complete ownership

of those deaths—by focusing on public safety, and by doing all that it can to protect its employees and contractors from the risks they face in their jobs and the public from the risks it faces when PG&E employees and contractors do not do their jobs effectively.

PG&E's Safety program now sits at the enterprise level and is managed and overseen by the Chief Safety Officer and Senior Vice President of Enterprise Health and Safety ("EH&S"). In June 2021, PG&E began implementing a regionalized model for the EH&S organization, which includes Regional Safety Directors with LOB, functional, and regional responsibilities. The Regional Safety Director for the Central Coast Region is responsible for supporting safety in Gas Operations, and the Regional Safety Director for the North Coast Region is responsible for supporting safety in Electric Operations.

In addition to organizational changes, PG&E is implementing a comprehensive, long-term plan, the "2025 Safety Plan," which, at a high level, aims to improve safety by addressing both PG&E's existing systems and its safety culture. In terms of systems, the plan primarily focuses on incorporating critical risk management into the Company's work, refining and improving safety standards, ensuring the universal use of effective safety tailboards, and managing public safety. This also includes a focus on contractor management, which is essential to improving safety in the future. In parallel, PG&E has continued its efforts to implement an Enterprise Safety Management System, which, after significant delays, the Company developed and began to implement throughout 2020 and 2021. To improve safety culture, the 2025 Safety Plan aims to increase and improve safety observations in the field; incorporate safety into hiring decisions, performance appraisals, and trainings; and assess and improve PG&E's safety culture using the National Safety Council's Safety Barometer Survey and associated action development and management template. It is important that PG&E stay committed to a strategic long-term safety plan and allocate sufficient resources to that plan. Additionally, given PG&E's ongoing leadership turnover, it is important that incoming

leaders in all roles fully commit to PG&E's plans. No organization can sustain long-term progress if there is substantial turnover of senior leaders, with each wave of leaders having their own particular priorities, even if each wave and individual operated during their respective brief tenures in good faith.

Further, management engagement with field-level employees is essential to improving safety, including by reducing injuries and fatalities. PG&E's emphasis on grassroots safety teams and engagement with its workforce as changes to policies and work procedures are made are important steps in becoming a safer organization. While PG&E has made progress, the Monitor team encourages the Company to continue its efforts to empower employees and contractors to raise safety issues, such that employees and contractors feel confident in their obligation and ability to stop work if they are concerned about safety. Importantly, the Company should also continue to provide employees contractors with the tools and support needed to mitigate safety issues.

VI. WILDFIRE MITIGATION EFFORTS

The Monitor team's work concerning PG&E's Electric Operations and wildfire mitigation efforts substantially began in early 2019, following multiple years of horrific wildfires. At that time, the Court imposed a number of probation conditions designed to promote safer and more thorough wildfire abatement efforts by PG&E. These included requiring PG&E to comply with all vegetation management laws; to meet the targets in its state-approved wildfire mitigation plan; to maintain traceable, verifiable, accurate and complete records; and to ensure that sufficient resources, both financial and personnel, were devoted to achieving the conditions of probation. The Court also ordered the Monitor team to conduct field inspections of PG&E's vegetation management and electric equipment work. (Apr. 3, 2019 Order, Dkt. 1040). The Court has since modified and augmented PG&E's conditions of probation on several occasions. *See* Exhibit 3.

PG&E's performance in Electric Operations has not matched its performance in Gas Operations and Compliance and Ethics. As detailed in prior reports to the Court, PG&E made many errors in design and execution of wildfire abatement efforts from the beginning of probationary review. *See, e.g.,* July 26, 2019 Letter to the Court, Dkt. 1089 (highlighting substantial numbers of missed trees and recordkeeping issues within PG&E's EVM program); Oct. 16, 2020 Letter to the Court, Dkt. 1247-1 (highlighting the lack of risk prioritization of PG&E's EVM work and deficiencies in PG&E's System Inspections program). Much more progress is required, both quickly and over a sustained period of years, as detailed below.

We doubt anyone would seriously contend that PG&E's performance has been even adequate, or that substantial improvement is not still imperative, given the staggering losses of life and property caused by recent wildfires for which the Company has either pleaded guilty criminally or otherwise been determined responsible. While progress is occurring, and should be recognized, there is a long way to go. Sustained, focused, and unwavering commitment in the future will be required to achieve stated goals.

By way of background, PG&E conducts its wildfire mitigation work pursuant to a Wildfire Mitigation Plan ("WMP") submitted to and approved by the CPUC, and this year, the California Office of Energy Infrastructure Safety. That WMP contains targets and metrics that form the basis of PG&E's annual wildfire mitigation work. The Monitor team does not only focus on whether PG&E meets the CPUC approved targets (the Company largely has, despite the tremendous wildfire damage caused). Rather, we focus also on *how* PG&E meets those targets and metrics, in terms of the quality of the work, and whether work is performed so as to reasonably maximize risk-mitigation. We evaluate those efforts through regular discussions with PG&E leadership, employees, and contractors performing the work (both in the office and in the field), as well as our

own field inspections of PG&E work. Information collected from that work forms the basis of our observations discussed herein.

As stated, PG&E substantially complies with the numerical targets set forth in the WMP, and where there are misses from CPUC requirements, they are oftentimes not far off. This is important because despite substantial compliance with the mitigation plans, PG&E's equipment continues to cause wildfires. We understand that the WMP process was meant to be a multi-year process, with the goal of substantially reducing wildfire risk over time. While that may be the case, the Monitor team emphasizes that achieving the targets and metrics in the WMP, as they have been set since 2019, has been insufficient to stop lethal wildfires. And since 2019, some core WMP targets, as submitted and approved, have been *decreasing* year over year, not increasing, including in PG&E's Enhanced Vegetation Management ("EVM") program. So while the path to success under the WMP process is an extended one, the Company would be well served to take a more aggressive approach to wildfire mitigation than it has in the past to stop wildfires today, understanding there are longer term initiatives that are also key, such as infrastructure replacement, which PG&E has identified is one of its most important safety steps going forward.

Notwithstanding the shortcomings and needed improvements in PG&E's wildfire mitigation efforts described below, there have been some positive steps. Perhaps one of the largest and most important improvements we saw during the Monitorship was the amount of resources and leadership brought to bear on the Company's risk-based planning and prioritization of wildfire mitigation work. There was a turning point in the fall of 2020, when PG&E's then new Chief Risk Officer Sumeet Singh established the Wildfire Risk Governance Steering Committee, comprised of various Company leaders whose divisions perform wildfire mitigation work. As a result of the efforts of this Committee and the Chief Risk Officer, all wildfire mitigation work performed by PG&E pursuant to the WMP underwent project-level selection, planning, scrutiny, and deliberation before

a committee whose focus, in sum, was to ensure the highest risk work was being addressed sooner rather than later according to PG&E's models.

This was important because addressing the highest risk work sooner rather than later was PG&E's stated goal when it first published its 2019 WMP, but that is not what was happening until PG&E's Chief Risk Officer changed the trajectory and focus of the Company's wildfire mitigation efforts in the fall of 2020. Prior to that time we raised to both PG&E and the Court that the Company had been completing the majority of its EVM work on lower priority circuits according to its own risk models. *See* Oct. 16, 2020 Letter to the Court, Dkt. 1247-1. That is no longer the case, and PG&E is on a better path now from a risk based planning and work execution perspective. That makes the people and State of California safer, but continued vigilance over the risk-based planning and execution of work will be necessary. Otherwise, work can get "done" and state requirements and targets can be "met," but with suboptimal corresponding risk-reduction.

VII. VEGETATION MANAGEMENT

VM is a critically important aspect of wildfire mitigation. From 2017-2021, as of October 13, 2021 data, PG&E has reported approximately 259 ignitions caused by vegetation striking PG&E's distribution assets in high fire-threat district ("HFTD") areas. Given the very real and catastrophic potential consequences of an ignition in PG&E's HFTD service territory, there is little room for error in vegetation management work, and the Company should promote a culture that does not tolerate any error in VM. To be sure, VM work is complex given the volume and dynamic nature of trees that threaten PG&E's electric lines. Tree growth and tree failure cannot be precisely predicted. But the reality of that challenge underscores the importance of devoting sufficient resources to ensure that vegetation risks are mitigated effectively, including by adopting more conservative trimming measures that remove guesswork and subjectivity as much as possible, while also maintaining vegetation in accordance with applicable regulations and PG&E policy. PG&E

would also benefit from adopting a uniform, territory-wide, and year-round approach to vegetation management scope and trimming in high fire-threat areas—one that exceeds regulatory minimum requirements.

Our work in vegetation management has focused on five main areas: (1) quality of work execution; (2) prioritization of work in terms of risk abatement; (3) scope of work; (4) recordkeeping; and (5) contractor management. The field inspection component of the Monitor team's review of PG&E's VM efforts began in the summer of 2019.

PG&E's VM organization has improved work quality since 2019. The Monitor team's field inspections have revealed that the percentage of trees missed by PG&E's EVM workers has decreased. PG&E has also taken significant recent steps to align the work being performed in the field with the risk-based priorities established by the Company's leadership—an alignment that was unacceptably missing in 2019 and 2020. However, in other areas, such as enhanced hazard tree assessments in HFTD areas and needed records improvements, PG&E concedes the need for improvements but has not yet effectively established or demonstrated sufficient reforms.

A. Background

PG&E's transmission and distribution lines receive annual vegetation inspections as a part of the Company's Routine VM program. During Routine VM work, PG&E is supposed to trim trees with potential to grow within the minimum clearance distance delimited by California regulations and remove hazard trees that pose a risk of striking the lines. In 2019, PG&E included EVM as a more robust component of its WMP commitments, pursuant to which PG&E agreed to perform enhanced tree work on select distribution circuits within HFTDs, with the ultimate goal of performing enhanced work on all 25,500 HFTD miles at some point during the multi-year EVM program. Enhanced work includes tree removals based upon region-specific tree-species analysis

and clearance of limbs overhanging primary distribution conductors. EVM records are largely administered through software referred to as Arc Collector.

B. Quality of Work Execution

The Monitor team assessed the quality of PG&E's VM work execution via various means, including unannounced field inspections performed in HFTDs as specified in the Court's probation order (Apr. 3, 2019 Order, Dkt. 1040). Field inspections are performed on distribution conductor segments subject to EVM and segments subject to Routine VM, that is, areas where EVM has yet to be performed, which includes the vast majority of PG&E's high threat areas.

As a general matter, the Monitor team sought to inspect at least 10% of PG&E's annual EVM mileage goal each year, but the mileage inspected was higher in 2019 due to PG&E's EVM scope changes and lower in 2020 due to COVID travel restrictions and statewide stay-at-home orders. When the Monitor team began inspecting PG&E's fieldwork in summer 2019, we inspected 130.49 miles and identified a substantial number of trees that were out of compliance with PG&E's EVM scope of work as reported in detail in a letter to the Court dated July 26, 2019, Dkt. 1089. Over half of the segments we inspected did not conform to the EVM scope. After several discussions between PG&E and the Monitor team in July and August 2019 regarding these deficiencies, PG&E implemented a new scope of work, new training materials, and a new training program. Since then, the Monitor team has noticed improvement. In fall 2019, the Monitor team inspected 323.93 miles of EVM work. Out of 25,165 trees inspected in fall 2019, the Monitor team identified 203 hazard trees, 33 radial clearance issues, and 119 overhang issues. In other words, 98.6% of strike trees—trees tall enough to strike electric assets—inspected by the Monitor team were in compliance with the EVM scope. In 2020, the Monitor team inspected 42.03 miles of EVM work. Out of 11,280 trees inspected in 2020, the Monitor team identified 83 hazard trees, 34 radial clearance issues, and 32 overhang issues. 98.7% of strike trees were thus in compliance with the

EVM scope. So far in 2021, the Monitor team inspected 199.75 miles of EVM work. Out of 32,269 trees inspected in 2021, the Monitor team identified 77 hazard trees, 24 radial clearance issues, and 53 overhang issues. That is, 99.5% of strike trees have been compliant with EVM scope in 2021. For additional year-over-year statistics from Monitor team EVM inspections, *see* Exhibit 4.

For areas not subject to EVM work, but still within the HFTD service territory (Routine VM), the Monitor team inspected 13.95 miles in summer 2019; 22.32 miles in fall 2019; 20.13 miles in 2020; and 138.71 miles in 2021. The Monitor team increased its mileage in 2021 because prior years' inspection results indicated that additional attention to Routine VM in HFTDs was warranted because of underperformance in that program as compared to EVM. Out of 4,661 trees inspected by the Monitor team in fall 2019, the Monitor team identified 59 hazard trees and 41 radial clearance issues. That is, 97.85% of strike trees were in compliance with the Routine VM scope in fall 2019. Out of 2,645 trees inspected in 2020, the Monitor team identified 19 hazard trees and 20 radial clearance issues. In 2020, 98.53% of strike trees were in compliance with the Routine VM scope. Thus far in 2021, out of 23,025 trees inspected, the Monitor team identified 268 hazard trees and 55 radial clearance issues. That is, 98.6% of trees have been in compliance with the Routine VM scope in 2021. For additional year-over-year statistics from Monitor team Routine VM inspections, *see* Exhibit 5. The Quality Management inspections performed by PG&E's internal group have identified a similar percentage of missed trees. PG&E's internal VM Quality team efforts are an improvement by PG&E during the last couple years. That is, PG&E recently has self-identified shortcomings and instituted corrections better than it historically has.

While PG&E's improvement from 2019 to 2021 on EVM is encouraging, these results are currently inadequate because they still allow very substantial wildfire risks even in EVM-worked areas. The Monitor team continues to find hazardous trees in the field missed by PG&E's workers. *See* Exhibit 6. While the analogy is admittedly imperfect, we doubt that a vehicle brake

manufacturer, or even officials in PG&E's nuclear or gas operations, would be satisfied with a 1.5% miss rate on important safety work. Moreover, extrapolating the Monitor team's inspection statistics across PG&E's full HFTD service territory suggests that approximately 60,000 trees were missed by PG&E in 2021, even after Enhanced and Routine vegetation management work. That is an unacceptably high number, given the threat each missed tree poses and the collective threat posed by such a volume of misses. As discussed further in Section VII.D below, enhancements to PG&E's scope of work, and better contractor management, may allow for greater risk mitigation.[2]

C. Prioritization of Work

The Monitor team's findings from our field observations and data analyses suggested that PG&E completed the majority of its 2019 EVM work in relatively low-risk portions of its HFTDs according to the Company's risk model. That unsatisfactory dynamic continued in 2020, with work spread roughly evenly across the highest and lowest ranked circuits under applicable risk models. *See* Oct. 16, 2020 Letter to the Court, Dkt. 1247-1. Put differently, while PG&E was "meeting state requirements" by doing sufficient EVM work in HFTDs, the parts of the HFTDs where actual work was being completed were not the highest risk portions of the HFTD. As a result, the "meeting requirements" approach achieved formalistic compliance with CPUC requirements without reducing risk in a commensurate way.

As noted, in the wake of concerns raised by the Monitor team about this approach (*see, e.g.,* Oct. 16, 2020 Letter to the Court, Dkt. 1247-1), PG&E has made significant improvement in the risk-based prioritization and execution of work in 2021. The Company developed a tree-weighted risk model for 2021 and committed to performing nearly all 2021 EVM work within the top 100

[2] To be clear, not every fire can be prevented through vegetation management; for example, a terrible wildfire could be caused by lightning alone and neither PG&E (nor any utility) would be responsible. There are other examples (irresponsible campers, animals, and large birds, etc.). However, when PG&E and its contractors perform vegetation work in high-threat areas, it is important that results are as close to 100% correct as is humanly possible, given the role EVM and VM play in risk mitigation and wildfire deaths.

circuit protection zones. This year, for example, PG&E has performed over 80% of EVM work in the top 10% of riskiest areas—to put that number in perspective, that percentage was only 18.6% in 2019, and even lower, 6.3% in 2020. *See* Exhibit 7 (showing percentage of EVM miles completed in 2019-2021 within the top 10% of risk-ranked circuit miles under PG&E's models each year). The Monitor team commends PG&E, and in particular its Chief Risk Officer, for the quick pivot to ensuring consistent use of a risk-based approach for EVM work in 2021 and, we expect, beyond.

D. Scope of Work

PG&E's scopes of work in both Routine VM and EVM could be improved to ensure that vegetation risks are better mitigated. First, PG&E limits radial clearance trimming to trees capable of growing within the minimum clearance distance within one year and limits Routine VM hazard tree removals to trees that could fail within one year. A more conservative approach would help ensure that risks are mitigated before they materialize, while further reducing potential error in what is oftentimes a difficult, subjective determination.[3]

Second, PG&E's EVM work—which goes above and beyond the minimum compliance requirements of Routine VM—is being performed slowly, that is, on *less than 10%* of the HFTD annually. Put another way, despite all of the emphasis the Company places on EVM, 90% (or more) of PG&E's HFTD territory annually is left untouched by the EVM program. The Company stated in 2019 that it expected to perform at least 2,450 miles of EVM work per year, with the goal of finishing EVM on all HFTD circuits by the end of 2026. But PG&E's annual targets decreased in 2020 and 2021 to 1,800 miles (and were approved at those levels by the CPUC). If this pace continues, the Company will need more than 10 years to complete EVM work on the HFTDs. Given

[3] We appreciate that state regulators may have views about the appropriate amount of clearance distances PG&E can create. We do not purport to speak for the CPUC and other regulators of course. However, given the severity and ferocity of recent wildfires, we would hope everyone would keep an open mind about more aggressive fire prevention efforts and whether regulations may need to be modified in light of tragic recent history.

the threat of wildfires in California, and the existence of a more effective EVM program, the Monitor team respectfully believes that PG&E should not limit its EVM targets to 1,800 miles per year out of the 25,500 HFTD miles.

One consequence of PG&E's limited annual target for EVM is that most trees across its HFTD service territory are not receiving detailed hazard tree assessments, which presently do not occur under the Routine VM program. PG&E developed a Tree Assessment Tool ("TAT") for EVM, which requires thorough inspection of trees—including, for example, 360-degree assessments. Because EVM is only performed annually on approximately 10% (now less) of PG&E's HFTD service territory, the great majority of trees to date have not received detailed 360-degree or TAT inspections on an annual basis. The Monitor team was also concerned that, after segments completed EVM, PG&E was not maintaining those segments to the EVM scope in future years. For example, vegetation "overhanging" the primary conductors was being cleared to the sky under EVM, but that conductor-to-sky clearance was not being maintained in future years. After discussing these issues with the Monitor team, PG&E recently informed the Monitor team that it soon will require 360-degree tree assessments in all HFTD areas by augmenting its Routine pre-inspection program and will maintain EVM-completed segments to the EVM scope going forward. Both are prudent initiatives, and demonstrate significant commitments, improvements, and investments.

Another consideration for PG&E is to implement a single, enhanced scope of vegetation work applicable to all HFTDs that applies year-round and exceeds regulatory requirements. This would bring uniformity to the vegetation management approach in HFTD areas, eliminate contractor confusion regarding scope, improve recordkeeping and, most importantly, result in greater annual risk reduction in HFTD areas.

E. Recordkeeping

Traceable, verifiable, accurate, and complete records are essential for ensuring public safety. From the beginning of the Monitor team's review of VM work, we have identified significant recordkeeping issues—which, to be fair, are often the result of decades of issues and conflicting systems, not merely recent developments or lack thereof. Nonetheless, that is an explanation and not an excuse, and this is an area where improvement will promote safer operations.

In 2019, we observed that PG&E's electronic Arc Collector maps sometimes reflected that electric conductor segments and trees were in the wrong location, inconsistent data was often recorded (such as trees assessed for removal as hazards but then given a prescription of "no work required"), and EVM work verification data was sometimes being deleted from the Arc Collector system. *See* July 26, 2019 Letter to the Court, Dkt. 1089, at 21-27.

In response to the Monitor team's recordkeeping feedback, PG&E made significant changes to its system in September 2019. Those changes included modifying how work was recorded, so that EVM work verification data would not be deleted, and instituting data checks to ensure that certain conflicting or missing data are fixed. PG&E also collected aerial Light Detection and Ranging ("LiDAR") data in early 2020 to improve the location of its electric conductor segments.

PG&E's technology team often fixes data issues, once identified, quickly. For example, in October 2020, as described in a letter to the Court dated Oct. 16, 2020, Dkt. 1247-1, the Monitor team observed a tree singed from contact with a primary conductor. A pre-inspector had twice flagged the tree as a "Priority 2 tag" to be worked within 30 days, but that pre-inspector did not have access to the database used to generate Priority 2 tags, and the work request was never generated. After the Monitor team raised this issue, the Company immediately identified the gap in its process and, in relatively short order, built a new mobile application through which any VM worker can

generate Priority tags. That is certainly helpful, but the goal must be to have a system where self-correction (without an external force) is routine.

Despite these improvements, PG&E's records are still not sufficiently reliable. First, PG&E plans to unify its fragmented VM records databases into a single tool, but the tool has not yet been developed and will not be applied to all VM programs until 2023 or 2024. Second, approximately one-third of the circuit maps were never updated from the inaccurate versions used in 2019. PG&E is undertaking a circuit-by-circuit process of updating the maps yet again, but the Monitor team continues to observe inaccuracies in even the newest maps. *See* Exhibit 8. Third, the Monitor team continues to observe inconsistent data within PG&E's records systems. *See* Exhibit 9. In sum, PG&E's progress in addressing the accuracy and integrity of its VM records has been slow. Given the history of recordkeeping issues with the Company, improvement here needs to remain a focus and priority.

F. Contractor Management

PG&E relies on contractors to perform its VM work. Accordingly, effective contractor management is critical to the success of PG&E's VM program (and other programs). The Court imposed a new probation condition on August 7, 2020 pursuant to which PG&E was required to staff an in-house VM inspector workforce of at least 30 inspectors by January 2021. (Aug. 7, 2020 Order, Dkt. 1243). These inspectors are important to PG&E contractor oversight. PG&E not only met that condition but has also significantly expanded its commitment to field monitoring work through in-house Vegetation Management Inspectors ("VMIs") and work verifiers. Both programs have generated actionable feedback in 2021 that PG&E used to clarify and materially improve its procedures. PG&E has also acknowledged that its VMI and work verification programs are not yet fully developed, so continued improvement and attention are and will be required.

To drive additional improvement in VM work quality, PG&E should (1) make procedures, scopes of work, and recordkeeping tools simpler for contractors to understand and (2) require ongoing, annual trainings and rigorous assessments for all pre-inspectors and work verifiers to ensure that hazard tree assessments are performed consistently across HFTDs.

VIII. ELECTRIC INFRASTRUCTURE INSPECTIONS AND REMEDIATION WORK

As explained below, while PG&E has made improvements to its electric infrastructure inspection and remediation programs, it has struggled to execute plans in a timely manner. PG&E needs to dedicate more resources to remediating identified risks, because its lack of emphasis on timely remediating lower priority repairs, and even some priority repairs, has produced a significant repair backlog. Recordkeeping issues persist, posing challenges to electric infrastructure inspection and remediation efforts. And the Monitor team's field review of PG&E inspections revealed ongoing quality issues, suggesting the need for more oversight and training. Our field reviews, however, typically do not identify imminent hazards, suggesting that PG&E inspectors are at least identifying and addressing the highest priority issues.

In 2019, PG&E established an enhanced inspection protocol to identify conditions that could present fire ignition risk. When launching its enhanced inspection program, PG&E undertook an unprecedented amount of work, inspecting all of its approximately 685,000 distribution poles, 50,000 transmission structures, and 200 substations in HFTDs in a calendar year. That 2019 effort led to an unprecedented number of orders (673,968) for remediation work ("tags"). There are over 500,000 tags from 2019 to present that remain unresolved to date. For 2020 and 2021, PG&E continued to inspect all infrastructure in Tier 3 HFTDs annually (although we understand PG&E may be considering to reduce the frequency of Tier 3 inspections—the riskiest areas—which we would not support in the near-term). PG&E moved to a three-year rotating inspection cycle for

infrastructure in Tier 2 HFTDs (one-third each year) and a five-year rotating inspection cycle for infrastructure outside of Tier 3 and 2 HFTDs (one-fifth each year).

A. PG&E's Wildfire Mitigation Plan Commitments to the CPUC

For each year since 2019, PG&E has set forth specific, annual inspection commitments in its WMP, in addition to internal goals. In 2019 and 2020, PG&E did not meet its inspection targets, which are largely aimed at ensuring that identified priority repairs are made in advance of fire season. In 2021, PG&E failed to inspect 5,107 distribution structures by the deadline. This was due to 41,000 structures that were added to the work plan in July, largely because of incomplete records identified through PG&E internal validation efforts. Since July, PG&E has continued to identify additional structures that should have been inspected by the July 31, 2021 deadline but were not mostly because of faulty records which do not accurately reflect assets in the field, including at least 995 distribution and two transmission structures.

In sum, in no year has PG&E met all of the inspection commitments in its WMP. PG&E would benefit from additional planning, resource, recordkeeping improvements, and procedural enhancements to ensure it meets all external and internal inspection commitments going forward. These inspections are important because they are a part of an integrated wildfire risk-abatement program that cannot function most effectively if one component is lagging.

B. Quality of Work

The success of PG&E's enhanced electric equipment inspections depends not only on timeliness, but also on quality. Since 2019, the Monitor team has conducted field inspections of a sample of PG&E's inspected electric structures across the high threat service territory. After the inspections, the Monitor team identified and reported to PG&E "potential exceptions," that is, field conditions that should have been identified by an inspector in accordance with PG&E guidance but were not, or a recordkeeping question that was answered inaccurately by a PG&E inspector. The

frequency and nature of the Monitor team's findings suggest ongoing quality concerns, and a continued need to improve PG&E's oversight of its contract workforce.

1. Distribution Inspection Results

In 2019, the Monitor team conducted an in-field review of 1,652 electric distribution structures in HFTDs that had been inspected by PG&E. Approximately 12% of the structures inspected by the Monitor team had potential exceptions related to field conditions, for a total of 222 missed field issues by PG&E inspectors across 201 structures. Approximately 34% of the structures had potential exceptions related to recordkeeping, for a total of 522 missed recordkeeping issues across 377 structures.

In 2020, due to COVID restrictions, the Monitor team conducted an in-field review of a much smaller sample of 94 distribution structures in HFTDs that were inspected by PG&E. Recognizing "small sample size" dynamics can skew outcomes, nonetheless approximately 48% of the sampled structures had potential exceptions related to field conditions, totaling 75 missed field issues by PG&E inspectors across 45 structures. Approximately 53% of structures had potential exceptions related to recordkeeping, for a total of 60 missed recordkeeping issues by PG&E inspectors across 50 structures.

In 2021, the Monitor team conducted an in-field review of 1,628 distribution structures in HFTDs that had been inspected by PG&E. Approximately 27% of the structures had potential exceptions related to field conditions, for a total of 583 missed field issues by PG&E inspectors across 435 structures. Approximately 31% of the structures had potential exceptions related to recordkeeping, for a total of 642 potential exceptions by PG&E inspectors across 507 structures. While these figures represent an improvement over the limited sample from 2020, there is a significant increase in the frequency of field condition-related potential exceptions (27%) as compared to 2019 (12%). For example, the number of field conditions related to pole damage

identified by the Monitor team in 2021 (164 potential exceptions) was substantially higher than 2019 (50 potential exceptions), suggesting that there may still be issues with the clarity of PG&E's pole damage criteria or with PG&E's training on that subject. The same holds true for field conditions where the PG&E inspector failed to identify structures with equipment deemed non-exempt by CAL FIRE and with dried vegetation present within a ten-foot radius of the pole (55 potential exceptions in 2021 compared to five in 2019). While the Monitor team has observed relatively few emergency conditions (that is, those that would require immediate attention from PG&E), it continues to find many conditions that could present fire ignition risk based on PG&E's own inspection criteria and guidance, including pole damage, guy wire clearance, and the proximity of splices to the structure. *See* Exhibit 10 for additional detail on observations.

2. Transmission Inspection Results

In 2020, the Monitor team established an inspections program whereby it conducted photographic inspections of PG&E's transmission assets using PG&E's aerial photography database. This method was used by the Monitor team because it was not realistic or safe for us to conduct in-field inspections of high towers, for example, either directly via ascents or by the Monitor team operating drones. The Monitor team reviewed 297 transmission structures that had been subject to aerial inspections by PG&E, meaning that the Monitor team reviewed the same helicopter and drone photographs that PG&E's AIR+ inspectors used in their aerial inspections. Approximately 83% of the steel structures inspected had potential exceptions that were not identified by PG&E, for a total of 291 missed issues across 123 structures. Approximately 78% of the wood structures also had potential exceptions, for a total of 243 missed issues across 116 structures. We acknowledge that PG&E uses additional inspection methodologies for transmission assets that may catch some of the issues missed by PG&E's AIR+ team, including ground and

climbing inspections, but those additional methods do not eliminate concerns raised by the potential exception numbers noted immediately above.

In 2021, the Monitor team inspected 304 electric transmission structures via PG&E aerial photography records. Approximately 47% of the steel structures inspected had potential exceptions, for a total of 160 missed issues across 88 structures. Approximately 53% of the wood structures also had potential exceptions, for a total of 136 missed issues across 76 structures. This decrease in the rate of potential exceptions coincided with improvements in the AIR+ training program and efforts to clarify the guidance materials utilized by inspectors, as well as a continuing accumulation of experience by AIR+ inspectors, but the numbers were still quite high. To be clear, in both 2020 and 2021, potential exceptions overwhelmingly were comprised of non-emergent conditions (e.g., non-acute contamination on an insulator), recordkeeping errors (e.g., failure to identify a structure as located near a dwelling), and situations where the Monitor team was unable to properly assess the condition of a component due to the insufficient quality of PG&E's aerial photographs. *See* Exhibit 11 for additional detail on the Monitor team's observations. Nonetheless, greater precision and performance can fairly be expected, given the safety impact the inspections have.

3. PG&E Quality Control Efforts

In 2021, PG&E made significant progress in developing and implementing additional quality control measures, including field verification for electric transmission and distribution asset inspections. PG&E also engaged external resources to complete a review of all of its tags involving C-hooks. PG&E has also been leveraging automated technologies and machine learning to further bolster its inspections programs, including through photographic analysis to "train" computers to spot equipment issues that warrant additional review. The efforts are a positive development in verifying and supplementing the quality of inspections.

C. Inspection Guidance Materials, Resources and Training

The quality of PG&E's enhanced inspections depends in large part on the clarity and objectivity of the questions asked of inspectors via checklists and the detail provided in job aids. In 2019, the Monitor team identified certain questions in PG&E's distribution checklist that were unclear and noted that PG&E's job aid was not tailored to conducting enhanced electric inspections. In 2020, PG&E made some improvements to its program, including revising its electric distribution inspection checklist to reduce ambiguities. PG&E also created a job aid specifically for enhanced distribution inspections that contained additional detail and illustrative photographs to improve consistency in identifying field conditions. In 2021, PG&E has further improved its job aids for both electric distribution and transmission inspections with additional details, diagrams, and photographs. There is still room for improvement. In particular, the guidance in the job aids is not well-tailored to the questions as worded on the inspection checklists. Additionally, System Inspections is responsible only for execution of inspection commitments, and it is not clear that inspectors have regular and meaningful access to other teams that could provide additional clarity on standards. Lastly, one of the most common issues identified by the Monitor team had to do with failure of PG&E inspectors to identify an asset as being located within 600 feet of a structure or dwelling. The high failure rate on an objective question like this indicates that inspectors may not be paying the requisite attention to detail throughout the inspection process, and that further training and oversight is required.

The quality of enhanced electric inspections also depends on the effectiveness of PG&E's inspector training program. As part of its onboarding process, PG&E provides inspectors with a multi-day training for enhanced inspections, including classroom and field sessions. From 2019 to 2021, the Monitor team has attended several of PG&E's in-person and virtual training sessions for enhanced electric distribution and transmission inspections. The Monitor team found these training

sessions generally informative, well-run, and critical to the success of PG&E's enhanced inspections. For further improvement, PG&E should incorporate more experiential field training into the curriculum and further utilize testing both during and at the end of trainings to ensure comprehension and retention of information.

D. Maintenance and Construction

While PG&E has improved in addressing high priority tags, there continues to be a high volume of outstanding remediation work, for which PG&E lacks a clear plan on which it has been able to effectively execute.

1. Volume and Timeliness of Remediation Work

PG&E's backlog of infrastructure-related remediation work has increased significantly since the start of enhanced inspections in 2019, although PG&E generally remains current on high priority tags (those requiring action immediately or within 90 days). For example, the overall number of pending, unresolved electric transmission and distribution tags increased by over 90,000 in 2019 and 60,000 in both 2020 and 2021. *See* Exhibit 12 for a visual representation of the backlog. As of June 30, 2021, there were 66,107 pending, unresolved transmission tags (25,013 in HFTDs) and 450,404 pending, unresolved distribution tags (222,058 in HFTDs). *See* Exhibit 13 for additional detail on the number of pending, unresolved electric infrastructure-related tags. Despite ongoing prioritization and remediation efforts, PG&E lacks a clear execution plan to address the increasing backlog in a timely way and has been constrained by available budget and resources in its ability to do so. Furthermore, conditions that are meant to be addressed within six months per PG&E guidance could sit unmitigated for several years. While PG&E has taken steps to address this, including implementing a "strike team" in 2021 focused on executing repairs and reassessing strategies related to tag prioritization and bundling, resource constraints continue to limit progress. As of July 2021, the estimated cost to address all existing tags was over $3 billion.

2. Effects of Pending, Unresolved Tags

PG&E, for the most part, resolves its Priority A tags (highest priority) in a timely way. PG&E's timeliness in addressing Priority B tags has needed improvement, and there is a tendency at PG&E to postpone mitigating its lower Priority E and F tags, contributing to backlog. Unresolved tags can collectively contribute to safety risks, including ignitions. The work of PG&E's Asset Failure Analysis Team may help to inform the prioritization of remedial work, by identifying conditions more likely to result in an ignition event. In any event, until PG&E resolves its significant backlog of remediation work, risky conditions will remain in the field.

For example, PG&E's recently established Asset Failure Analysis Team causally connected a June 2021 ignition to a broken cross arm. The cross arm was first identified in connection with an August 19, 2019 patrol. The tag had a due date of February 19, 2020 (a 6-month Priority E tag). The repair was permitted and ready for construction in April 2020 (which was already late), but was never completed. On September 10, 2020, the notification was reassessed and the crew lead requested that the work be expedited before the 2021 fire season (that is, August 30, 2021). On June 16, 2021, there was an ignition, which PG&E's Preliminary Ignition Investigation Report ("PIIR") attributed to "a rotten and decayed secondary, wooden cross arm failing and igniting the light, flashy fuels below the pole." As of the date of the PIIR, there were 1290 open notifications on the same circuit associated with common ignition drivers, of which 886 were past due and 256 were due within six months. Of these, 66 open notifications were associated with cross arms, of which 55 were past due and 11 were due within six months. The Monitor team recognizes PG&E's Asset Failure Analysis Team and the candid analysis contained in PIIRs, but until more is done by PG&E with the information in such reports, that is, actually addressing these risks in the field, PG&E's equipment will continue to cause unnecessary ignitions.

3. Field Safety Reassessments ("FSRs")

The FSR process, by which structures with pending, unresolved tags are periodically reviewed, is a stopgap measure put in place by PG&E to ensure that conditions do not further deteriorate while electric remediation work is pending, given the significant backlog of such work. While the Monitor team understands the need to reassess conditions when they are not timely remediated, FSRs divert resources away from enhanced inspections and execution of electric remediation work, and would, for the most part, be altogether unnecessary if PG&E were to address its asset repair tags in a timely way. In essence, while the FSR process is necessary, it has served to somewhat normalize the practice of not timely addressing "lower priority" repair tags, which can and do result in ignitions, as exemplified by the June 16, 2021 ignition identified above. While that ignition was small, had weather, moisture, or location circumstances been different, so too could have the outcome—PG&E cannot leave these matters to luck.

E. Recordkeeping

Recordkeeping issues that affect other operations also exist for electric infrastructure assets. PG&E has various recordkeeping issues that limit its electric infrastructure inspections and remediation programs, as PG&E does not maintain traceable, verifiable, accurate, and complete records of its electric infrastructure.

1. Paper Records

PG&E has migrated to mobile devices and applications for many aspects of its inspections program. This is an improvement. However, PG&E still uses paper records to document remediation work performed, for idle facilities, and to redline as-built drawings. This use of paper records can result in inaccuracies when information is migrated to electronic records due to transposition errors. Use of paper records also delays information transmission to the electronic

system of record, which can result in data discrepancies between the paper and electronic databases until the transposition occurs. Data analysis is also more difficult with paper records.

2. Asset Location Issues

PG&E records do not always accurately reflect the existence and/or location of its assets. In some instances, records misidentify the location, type, or even the existence of an asset, resulting in inefficient and missed inspections. In both 2019 and 2020, there were issues with the accuracy of asset geo-location data provided to inspectors. These issues have existed for years, and until recently, PG&E has been slow to remediate the problem. In 2021, PG&E worked on pilots to identify these inaccuracies and verify location data prior to inspections to minimize disruptions to inspection execution. Efforts to validate the asset registry in 2021 resulted in the addition of thousands of assets to PG&E's inspections work plan, that is, assets that were supposed to be in the 2021 plan but were not initially due to faulty records. Given the large number of structures and the need for field personnel to verify electric asset location data and reconcile internally conflicting records databases, PG&E estimates it could take years to verify the accuracy of all structure location data and for its records to accurately reflect the existence of all electric assets in its service territory. The Monitor team suggests that greater resources be dedicated to these efforts moving forward as PG&E over the past several years has not devoted an appropriate level of attention and resources to these issues.

3. Asset Component Age

Probation Condition No. 9, imposed by Judge Alsup in 2020, requires PG&E to record the age of critical electric transmission tower components in HFTDs; to make conservative assumptions where age is unknown; to implement a program to determine the expected useful life of critical components; and incorporate that information into its risk-based asset management programs. (Apr. 29, 2020 Order Modifying Conditions of Probation, Dkt. 1186). The purpose of this probation

condition is, in essence, to prevent wildfires by alerting PG&E that a transmission structure component, the failure of which could cause an ignition, is approaching the end of its useful life and should be replaced—like, according to state authorities, the C-hook that should have been replaced but instead failed and caused the Camp Fire and related 84 deaths and property damage. While PG&E experienced some delays in compliance with this probation condition, PG&E is now on track to comply. This is a substantial positive development.

PG&E's effort to collect component-level age data and to apply conservative assumptions where such data are not available is ongoing, and PG&E plans to complete its work for all 550 HFTD transmission circuits by the end of 2022. Currently, PG&E projects that by March 31, 2022 it will have developed risk models for each critical component grouping, incorporating component age, certain hazards, and wind threats to calculate expected useful life, while incorporating that data into its electric asset management plan. It is important that PG&E maintain focus and sustain progress to ensure this project is timely completed after probation ends.

4. Other Recordkeeping Issues

Recordkeeping issues have caused other problems in the electric space. A 2020 audit indicated there were 41,000 structures with missing or incomplete inspection records. In March 2021, PG&E self-reported to the CPUC that enhanced inspections were not performed on 24 hydroelectric substations. Recordkeeping gaps caused this oversight.

It bears mention that PG&E, for the most part, is now self-identifying many of these issues. Continuing to provide resources to internal teams to identify and remediate recordkeeping issues will be critical, as well as empowering those employees to raise matters and address them as they are identified, after probation ends.

IX. SYSTEM HARDENING PROGRAM

PG&E's system hardening program is a multi-year project aimed at reducing wildfire risk by enhancing PG&E's electric distribution system infrastructure through asset replacements, upgrades, undergrounding, and other means. According to the Company, system hardening is one of the most, if not the most, impactful wildfire mitigation initiatives the Company can undertake.

Over the past three years, PG&E's system hardening program has increasingly revolved around mitigating wildfire risk. Importantly, PG&E takes into account wildfire risk at several points in the process from identifying, scoping, and approving system hardening projects. While system hardening mileage targets have decreased over the past couple years, PG&E is on track to meet its target for 2021 and plans to ramp up mileage in 2022 and 2023.

PG&E faces certain challenges with respect to system hardening. In particular, PG&E personnel report that cities and counties can take a very long time to review and grant permits. Additionally, PG&E's ability to scale up annual system hardening mileage is subject to the impact of potential wildfires (that is, PG&E's annual hardening plans are oftentimes impacted by the need to rebuild areas destroyed by wildfires), and PG&E's ability to secure necessary resources, both personnel and financial.

A. System Hardening Approval Process

PG&E's system hardening planning function identifies potential electric system hardening projects using risk-based criteria, for example: (1) risk models that identify high-risk areas; (2) downed wires; (3) clusters of repair tags in the same geographic area; (4) whether system hardening in certain areas can help prevent Public Safety Power Shutoff ("PSPS") events; and (5) whether an area needs to be rebuilt due to wildfire damage. In addition, PG&E is increasingly seeking to underground its assets, thereby significantly mitigating future risk. PG&E has also engaged Public Safety Specialists (PSSs), who identify high-risk areas through on-the-ground review of PG&E's

service territory and electric assets. PG&E then incorporates those learnings into system hardening planning and project selection.

B. Decreasing Targets

In 2019, PG&E set a target of hardening all electric distribution assets in Tier 2 and Tier 3 HFTD areas (spanning approximately 7,100 miles) by approximately 2029. As part of this initial plan, PG&E set a target of hardening 150 miles in 2019 and forecasted 600 miles per year for 2020-2022. PG&E later reduced its 2020 forecast mileage to a target of 220 miles and then later PG&E reduced its 2021 target to 180 miles.

This trend of reducing system hardening mileage targets over the past couple of years does not comport with the Company's position that system hardening is the most effective wildfire mitigation measure. Using the initial 2019 Wildfire Safety Plan as a benchmark, if anything, the Monitor team would have expected to see these targets increase, not decrease, given the increasing threat of wildfires. PG&E's reasoning for decreasing the targets in 2020 from the original forecast—that the original forecasts were ambitious to begin with—is unsatisfactory, given that these were PG&E's own proposed goals. Had the Company planned and allocated sufficient resources, it could have made more progress.

C. 2021 System Hardening

For 2021-2023, PG&E's criteria for its system hardening program includes: (1) 80% of system hardening miles constructed by PG&E in 2021-2023 must be (a) located in the top 20% of the riskiest areas according to the new risk model, (b) fire rebuild miles, or (c) PSPS mitigation miles; and (2) 10% of all system hardening miles in 2021-2023 must be underground or line removal work. This year, PG&E has hardened approximately 168 miles, as of November 4, 2021. Notably, only approximately 36.5 of the 168 miles were located in the top 20% of the riskiest areas in this first year of PG&E's three year plan. Nevertheless, PG&E personnel anticipate that PG&E will

harden approximately 200 total miles in 2021 (including traditional hardening in place, fire rebuild work, and PSPS mitigation work), thereby exceeding the 2021 target of 180 miles.

Out of the approximately 168 miles currently constructed, approximately 30% of the miles are either underground or line removal projects, which far exceeds PG&E's target for at least 10% of its system hardening work to be undergrounded miles (or removal of lines altogether). By the end of 2021, PG&E expects that approximately 32% of its system hardening miles will be either underground or line removal projects. These metrics represent a significant improvement and risk reduction over years past. Sustained aggregate progress in the future will also be important, in addition to percentages going forward.

D. Undergrounding Initiative

In July 2021, PG&E announced an initiative to underground approximately 10,000 miles of electric distribution lines in HFTDs. The Monitor team applauds PG&E's commitment to undergrounding to mitigate wildfire risk but notes that some serious questions and issues remain regarding PG&E's implementation of the undergrounding initiative.

For example, PG&E did not specify a timeframe by which it expects to complete the undergrounding of 10,000 miles, but indicated an intention to harden up to 1,000 miles per year as part of the program. As of October 20, 2021, PG&E expects to underground approximately 66 miles in 2021 and a total of 327 miles from 2021-2023. Notably, there is substantial skepticism among PG&E field personnel that PG&E can feasibly underground more than 500 miles per year using current technology and hardening methodologies. Other open questions and issues are discussed below, and relate to matters of permitting, resources (both personnel and financial), and diversion of resources as a result of wildfire rebuild efforts.

E. Challenges

1. Permitting

While traditional system hardening projects typically take approximately 12 to 18 months from planning to completion of construction, PG&E typically completes fire rebuild projects within a few months. PG&E personnel report that the timing discrepancy is attributable to two factors: (1) for traditional system hardening projects, cities and counties can take a very long time to review and grant permits; and (2) for fire rebuild projects, California governmental agencies assist with expediting permitting to help restore power. PG&E should attempt to work with governmental agencies to expedite permitting for traditional system hardening projects, not just those involving areas damaged by fires.

2. Scaling of the Distribution Hardening Program

PG&E personnel report that scaling up from 200-300 miles per year (i.e., 2020-2021) to approximately 1,000 miles per year in later years will likely present two substantial challenges. One challenge is that PG&E may have difficulty securing the necessary volume of qualified contractors to complete the work. Additionally, system hardening is the most expensive mitigation effort, and increasing annual system hardening funding by more than twofold could mean that other risk mitigation work receives less funding. So while PG&E makes investments into its long-term hardening program, it will remain important to ensure that near-term wildfire mitigation measures receive appropriate resources.

3. Fire Rebuild Work

Like many other types of risk mitigation work, system hardening work is often delayed or de-prioritized by annual wildfires. PG&E must divert resources to rebuild fire damaged areas, which impacts PG&E's ability to carry out hardening efforts according to its plans and risk models. In mid-2019, PG&E began counting projects built to the fire rebuild standard toward its annual

system hardening goal. These projects involve replacing and rebuilding assets burned by a wildfire (including those caused by PG&E). Notably, without including the fire rebuild miles in the total system hardening miles—including those in the footprint of the Camp Fire in Butte County—PG&E would not have satisfied its annual system hardening WMP target for 2019 or 2020.

X. WILDFIRE EMERGENCY PREPAREDNESS AND RESPONSE

Since the 2017 wildfires, PG&E has worked to improve its emergency response and situational awareness capabilities to address fire risk. PG&E has made significant progress and refinements to its PSPS program, which has prevented over one thousand potential ignitions. The Company has also innovated through its enhanced power line safety settings program ("EPSS").

A. PSPS

The PSPS program is often unpopular but it is effective and has almost certainly saved lives. According to PG&E records, since PG&E began its PSPS program in 2018, it has reported roughly 1,450 damage or hazard incidents across 19 actual PSPS events, each of which could have resulted in an ignition. The Monitor team understands that a more ideal situation would be that PG&E had historically (that is, over the last generation at least) invested more in hardening infrastructure and in maintaining vegetation in a way that would obviate the need for proactive deenergization on the scale used by PG&E today. Unfortunately, however, the current state of affairs requires PG&E to preemptively deenergize assets in areas with forecasted adverse weather conditions of sufficient severity and high fire potential. The Monitor team fully acknowledges the burden PSPS places on affected customers. But again, there is little dispute that PSPS has saved lives, and potentially many lives, in the current wildfire environment.

Since launching the PSPS program in 2018, PG&E has continued to develop, improve, and automate it. For example, PG&E has: (1) enhanced the granularity and resolution of its weather and fire potential forecasting models; (2) improved its customer impact mapping accuracy; (3) utilized

PSPS impact mitigation measures; (4) improved customer notifications; (5) increased the number of Public Safety Specialists to better coordinate with external parties; (6) created the Safety and Infrastructure Protection Team to assist with field observation and mitigation efforts; (7) shortened post-event restoration times; and (8) most recently, incorporated vegetation management and asset data into its scoping decisions.

Notwithstanding this progress on the PSPS program, certain aspects of the PSPS program warrant additional attention.[4] First, during multiple 2019, 2020, and 2021 PSPS events, PG&E failed to notify all account holders at impacted service points in advance of deenergization—including critical facilities and members of PG&E's medical baseline program. The Monitor team recognizes that it may not be possible to notify every single customer, but PG&E must continue improving its notification success rates. Late or no notice is not merely an inconvenience; for some customers, especially those in the medical baseline program, notification is critical.

Second, while PG&E now offers many services to impacted customers during deenergization, including Customer Resource Centers, 55% of customers recently surveyed by PG&E indicated that they were unsure or unaware of the resources PG&E provides during PSPS events to customers with disabilities or other medical and acute needs. For these critical services to be useful, customers must know about them.

B. Enhanced Power Line Safety Settings

PG&E took quick action in the wake of the Dixie Fire to reduce ignitions by adjusting settings on line reclosers and circuit breakers to reduce fault energy flowing through lines, thereby reducing the potential for ignition events. This process is referred to as EPSS or "fast-tripping." Since the implementation of this program in late July of this year, PG&E is reporting a 46%

[4] Nothing in this report is intended to, nor should be interpreted to, conflict with or supersede any guidelines, opinions, findings, or corrective actions issued by the CPUC or any other regulator with jurisdiction over PG&E's implementation of PSPS events.

reduction in PG&E attributable ignitions in HFTDs as compared to its three year average. As a new program, there is more data to be collected and analyzed, but the early indications are that this measure, which does result in more frequent and longer outages for customers, is preventing fires.

XI. CONTINUING CHALLENGES

PG&E needs to continue to make meaningful improvements across all aspects of its operations to protect the citizens of California as well its employees and contractors. Those improvements are more challenging given the continuing challenges PG&E faces.

A. Leadership Turnover

One overarching item across the entire Monitorship is that virtually all areas of the Company have seen substantial and repeated turnover in leadership. There have been five Chief Executive Officers; six heads of Gas Operations; four heads of Electric Operations; and five heads of the Safety Organization, with the current head in an interim role, during the Monitorship. The Company also has implemented numerous changes to its organizational structure that have variously altered management and employee reporting relationships. In addition to the management, reporting, and leadership changes, there have been no less than 45 different members of the Board of Directors since 2017.

These leadership changes have an impact on the organization and can make necessary culture changes even more difficult. Employees who have been with PG&E for 20 or 30 years can become disillusioned with what they see as ever-changing direction and messaging, and a lack of continuity of programs and priorities. Those employees need to understand that the core values of safety, speaking up, and doing the right thing remain unchanged.

As an initial step, it is important that PG&E's Board of Directors focus on hiring and retaining the right set of leaders to move PG&E forward. It is important for PG&E to have real stability in the coming years in each aspect of its leadership.

B. Records Integrity

PG&E still struggles with records. PG&E needs to continue to devote substantial resources to enhancing its records, particularly in Electric Operations. Traceable, verifiable, accurate, and complete records underpin safe operations, from permitting employees to accurately understand asset health and inform repair decisions, to ensuring that vegetation issues are appropriately logged, communicated, and remediated. The lack of traceable, verifiable, accurate, and complete records was at the heart of the issues that led to the San Bruno gas explosion. In the wake of San Bruno, PG&E undertook an effort to overhaul its Gas Operations system of record to ensure its accuracy. However, no such effort was successfully implemented in Electric Operations and PG&E is still playing catch-up to achieve in Electric what it sought to do in Gas years ago—build an accurate system of record that reflects the reality of what is in the field.

C. Contractor Management

PG&E, consistent with industry practice, substantially relies on its contract workforce to perform wildfire mitigation efforts. PG&E needs to continue to focus on enhancing its relationship, communications, oversight, and expectations of its contract workforce. PG&E must also do more to try to achieve continuity of the contract workforce. Whether it be vegetation management or electric infrastructure inspections, PG&E's contract workforce has experienced high turnover in the past several years. For example, there has been a different group of contractors involved in electric equipment inspections each year since PG&E implemented its WMP. Similarly, the vegetation management contractor workforce regularly turns over. That turnover, like leadership turnover, prevents continuity in PG&E's programs, and results in a lack of familiarity and understanding of PG&E's service territory and equipment. With the high turnover, there is little opportunity to instill necessary cultural values into that workforce, including a "safety first" mentality, as described in greater detail below.

D. Long-Term Safety Projects

PG&E is demonstrating a willingness to take an unprecedented and significant step to make its infrastructure more fire resilient—such as its announcement to underground over 10,000 miles of distribution line in high threat areas. However, it will likely take at least 15 to 20 years (even assuming an ambitious and accelerated 500 miles, even 700 miles, of undergrounding per year) for these efforts to be completed. PG&E must commit to these long-term projects through its planning, budgeting and operations. It cannot put forth lofty goals and then let progress slow or deadlines slip once probation ends.

E. Near-Term Execution of Work

During those 15 to 20 years, progress on long-term projects alone will not be a panacea. Near- and intermediate-term planning and execution of other work will remain critical. The safety of the residents of PG&E's service territory requires that current PG&E wildfire mitigation efforts be executed with precision. This is not an easy task—especially given the vast contract workforce that PG&E utilizes to conduct so much of its wildfire mitigation work—but it is necessary due to the unforgiving and wildfire-prone service territory in which PG&E operates. In the vast majority of the country, the consequences of vegetation contact with a power line or the failure of electrical equipment are oftentimes reliability issues, that is, potential power outages. In PG&E's service territory, the consequences of a single misstep—a missed hazard tree, the failure to replace a corroded C-hook—can be death and destruction. Currently, as reflected by our inspections findings reported above, there are too many missteps.

Achieving flawless execution of work will take more than just technical skill and oversight of work in the field—it will require the adoption of a safety first mentality that permeates the entire organization and becomes embedded in the DNA of PG&E's employees and its contractors. Such a mentality is currently missing. A safety first mentality cannot just be a talking point at meetings

or some mantra that is repeated to the point that it loses meaning with employees. For example, PG&E has a stated mission to be the safest utility in the United States—it has been saying that for some time. However, our field inspections of PG&E's vegetation management work and electric equipment continue to find issues that were missed by PG&E workers in the field, year over year. Many of these issues, like the identification of a missed hazard tree, or the assessment of pole damage, can present "close call" situations where someone not erring on the side of caution might decide to leave the risk in the field instead of mitigate the problem. PG&E must instill in its workforce, including its management, to err on the side of caution, regardless of any cost-cutting initiatives or budget targets. And PG&E must empower employees to remove the risk without being second-guessed. Too many employees have expressed skepticism about PG&E's actual commitment to safety, being able to stop jobs and deliver bad news. It does not matter if the employees are "correct" or not today; their broad perception itself is a risk factor. PG&E has attempted to change the DNA of its workforce on these issues, but it must sustain those efforts going forward.

F. Attention to Resources in Gas Operations

In its efforts to overcome all of these challenges, PG&E must also be cognizant of and careful of focusing too much on electric and wildfire mitigation and allowing backsliding on the progress made to date in Gas Operations. Specifically, PG&E cannot pull too many resources from Gas Operations without cannibalizing the talent necessary to maintain operations. Numerous gas leaders and managers have moved over to focus on wildfire mitigation efforts—both on a temporary and permanent basis. While that work is critically important, PG&E must ensure that there is an appropriate depth of talent and experience in Gas Operations as well.

XII. CONCLUDING REMARKS

There is no doubt that PG&E has improved during the term of the Monitorship in both Gas and Electric Operations and the Company's practices are becoming safer. Unsurprisingly, much more progress has been made on the Gas Operations side of the Company during the more than eleven years since San Bruno than in Electric Operations in the fewer years since the Wine Country wildfires of 2017. The Monitor team does not doubt the sincerity of the efforts of PG&E leaders facing these safety challenges. But results on the Electric Operations side have been inadequate and substantial additional improvement and investment is required after probation ends. Further progress will require sustained commitment in the face of real challenges. And it cannot come at the expense of cannibalizing substantial progress made in Gas Operations and Compliance and Ethics.

The first people we met with after the Monitorship effort was underway were the surviving family members of some of the San Bruno victims. They should know that the tragic deaths of their loved ones did prompt change that hopefully will spare others from experiencing the losses they and their loved ones endured from prior PG&E failings in Gas Operations. We also hope that the initial progress we have seen on the Electric Operations side will over time substantially reduce risk from wildfires and the death and destruction they can cause.

On a final note, we strongly encourage policymakers to keep an open mind about whether reforms are possible in state regulations and oversight policies. Again, we do not doubt the sincerity of efforts. But doing "more of the same" may not be enough on its own, given that often PG&E substantially complied with state mandates and goals, in important respects at least, and terrible fires, deaths, and destruction nonetheless occurred. Perhaps regulatory changes, or experiments with new approaches, may yield better results in light of recent history and learnings.

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EXHIBIT 1: SAN BRUNO GAS EXPLOSION VICTIMS & WILDFIRE VICTIMS FROM WILDFIRES ATTRIBUTED TO PG&E BY CAL FIRE

San Bruno Gas Explosion Victims (2010)[1]

1. Lavonne Bullis, 82
2. Greg Bullis, 50
3. William Bullis, 17
4. James Franco, 58
5. Jacqueline Greig, 44
6. Janessa Greig, 13
7. Jessica Morales, 20
8. Elizabeth Torres, 81

Butte Fire (September 9 – October 15, 2015, Butte County)[2]

877 Structures Destroyed, 70,868 Acres Burned, 2 Killed

1. Owen Goldsmith, 80
2. Mark McCloud, 65

Atlas Fire (October 8, 2017 – February 19, 2018, Napa County)[3]

120 Structures Destroyed, 51,624 Acres Burned, 6 Killed

1. George Chaney, 89
2. Sally Lewis, 90
3. Charles Rippey, 100
4. Sara Rippey, 98
5. Teresa Santos, 50
6. Edward Stone, 79

Cascade Fire (October 8, 2017 – February 19, 2018, Yuba County)[4]

264 Structures Destroyed, 9,989 Acres Burned, 4 Killed

1. Stanley Coolidge, 78
2. David Patrick Culp, 76
3. Roseann Hannah, 53
4. Sandra Picciano, 77

[1] http://www.cnn.com/2010/US/09/22/california.pipeline.explosion/index.html; https://abc7news.com/archive/7694483/; https://abc7news.com/archive/7660103/; https://www.mercurynews.com/2010/09/13/san-bruno-fire-victim-jessica-morales-20-wanted-to-be-a-fashion-designer/; https://latimesblogs.latimes.com/lanow/2010/09/81-year-old-woman-named-as-fourth-fatality-victim-in-san-bruno-gas-explosion.html.

[2] https://www.fire.ca.gov/incidents/2015/9/9/butte-fire/; https://www.kcra.com/article/coroner-80-year-old-identified-as-2nd-man-killed-in-butte-fire/6424962.

[3] https://www.fire.ca.gov/incidents/2017/10/8/atlas-fire-southern-lnu-complex/; https://www.kqed.org/forum/2010101862302/remembering-those-who-died-in-the-north-bay-wildfires.

[4] https://www.fire.ca.gov/incident/?incident=608ed849-d1ec-4b0d-a477-d1b8e9c7e6dd; https://www.kqed.org/forum/2010101862302/remembering-those-who-died-in-the-north-bay-wildfires,

Nuns Fire[5] (October 8, 2017 – February 19, 2018, Sonoma County)[6]
1,355 Structures Destroyed, 56,556 Acres Burned, 3 Killed

1. Garrett Paiz, 38
2. Lee Chadwick Rogers, 72
3. Daniel Southard, 71

Redwood Valley Fire (October 8, 2017 – February 19, 2018, Mendocino County)[7]
546 Structures Destroyed, 36,523 Acres Burned, 9 Killed

1. Irma Bowman, 88
2. Roy Bowman, 87
3. Janet Kay Costanzo, 71
4. Elizabeth Charlene Foster, 64
5. Jane Gardiner, 83
6. Kai Shepherd, 14
7. Kressa Shepherd, 17
8. Steve Bruce Stelter, 56
9. Margaret Stephenson, 86

Camp Fire (November 8-15, 2018, Butte County)[8]
18,804 Structures Destroyed, 153,336 Acres Burned, 84 Killed

1. Joyce Acheson, 78
2. Herbert Alderman, 80
3. Teresa Ammons, 82
4. Rafaela Andrade, 84
5. Carol Ann Arrington, 88
6. Julian Binstock, 88
7. David Bradburd, 70
8. Cheryl Marie Brown, 75
9. Larry Alan Brown, 72
10. Richard Clayton Brown, 74
11. Andrew Burt, 36
12. Joanne Caddy, 75
13. Barbara Jean Carlson, 71
14. Vincent Mario Carota, 65
15. Dennis Clark Jr., 49
16. Evelyn Cline, 81
17. John Arthur Digby, 78
43. T.K. Huff, 71
44. Gary Lee Hunter, 67
45. James Warner Kinner, 83
46. Warren Lessard, 68
47. Dorothy Lee Mack, 88
48. Sara Magnuson, 75
49. Joanne Dolores Malarkey, 90
50. John Malarkey, 89
51. Christopher Maltby, 69
52. David William Marbury, 66
53. Deborah Morningstar, 65
54. Helen Pace, 84
55. Joy Porter, 72
56. Beverly Powers, 64
57. Robert Quinn, 74
58. Joseph Rabetoy, 39
59. Forrest Rea, 89

[5] Note that CAL FIRE reports the Nuns fire along with the Adobe, Norrbom, Pressley, Partrick, and Oakmont fires, collectively also referred to as the "Central LNU Complex" fires.

[6] https://www.fire.ca.gov/incidents/2017/10/8/nuns-adobe-norrbom-pressley-partrick-fires-oakmont-central-lnu-complex/; https://www.kqed.org/forum/2010101862302/remembering-those-who-died-in-the-north-bay-wildfires.

[7] https://www.fire.ca.gov/incidents/2017/10/8/redwood-valley-fire-mendocino-lake-complex/; https://www.kqed.org/forum/2010101862302/remembering-those-who-died-in-the-north-bay-wildfires.

[8] https://www.fire.ca.gov/incidents/2018/11/8/camp-fire/; https://www.buttecounty.net/Portals/30/CFReport/PGE-THE-CAMP-FIRE-PUBLIC-REPORT.pdf?ver=2020-06-15-190515-977; http://extras.chicoer.com/campfireremembrances/.

18. Gordon Dise, 66
19. Paula Susan Dodge, 70
20. Randall Paul Dodge, 66
21. Andrew James Downer, 54
22. Robert John DuVall, 76
23. Paul Ernest, 72
24. Rose Farrell, 99
25. Jesus Pedro Fernandez, 48
26. Jean Forsman, 83
27. Ernest Foss, Jr., 63
28. Elizabeth Gaal, 80
29. Sally Gamboa, 69
30. James Doyle Garner, 63
31. Richard Jay Garrett, 58
32. William Godbout, 79
33. Shirley Haley, 67
34. Dennis Hanko, 56
35. Anna Irene Hastings, 67
36. Jennifer Lynn Hayes, 53
37. Christina Heffern, 40
38. Ishka Heffern, 20
39. Matilde Heffern, 68
40. Dorothy Lee-Herrera, 93
41. Louis Herrera, 86
42. Evva Holt, 85
60. Vernice Mathilda Regan, 95
61. Ethel Colleen Riggs, 96
62. Lolene Rios, 56
63. Gerald Rodrigues, 74
64. Frederick Salazar Jr., 76
65. Phyllis Salazar, 72
66. Sheila Santos, 64
67. Ronald Schenk, 74
68. Berniece Schmidt, 93
69. John Sedwick, 82
70. Donald Shores, 70
71. Kathy Lynn Shores, 65
72. Judith Sipher, 68
73. Larry Smith, 80
74. Russell Stewart, 63
75. Victoria Taft, 67
76. Shirlee Teays, 90
77. Joan Carol Tracy, 82
78. Ellen Walker, 72
79. Donna Ware, 86
80. Isabel Webb, 68
81. Marie Wehe, 78
82. Kimberly Wehr, 53
83. Carl James Wiley, 77
84. David Young, 69

Zogg Fire (September 27 – October 13, 2020, Shasta County)[9]
204 Structures Destroyed, 56,338 Acres Burned, 4 Killed

1. Karin King, 79
2. Alaina Rowe McLeod, 46
3. Feyla McLeod, 8
4. Kenneth Vossen, 52

Dixie Fire (July 13 – Oct. 25, 2021, Butte, Plumas, Lassen, Shasta, and Tehama Counties)[10]
1,329 Structures Destroyed, 963,309 Acres Burned, 1 Killed

1. Marcus Pacheco, 53 (complications from COVID-19)

[9] https://www.fire.ca.gov/incidents/2020/9/27/zogg-fire/; https://www.latimes.com/california/story/2020-10-22/zogg-fire-lives-lost-shasta-county-california-wildfire.

[10] https://www.fire.ca.gov/incidents/2021/7/13/dixie-fire/; https://www.fs.usda.gov/inside-fs/memorial/remembering-marcus-pacheco. There has been no public report from CAL FIRE attributing the Dixie Fire to PG&E, and the Monitor team takes no position on fire cause or origin. This fire is included here due to the significant media and other attention on PG&E's equipment and the Dixie Fire.

EXHIBIT 2: FIFTEEN ORIGINAL TECHNICAL GAS ORDER REQUIREMENTS (DKT. 916)

Requirement One

Implementation of policies and procedures sufficient to comply with CPUC Decision 16-09-055 (effective Sept. 30, 2016) relating to the handling of safety citations and timely reporting of self-identified potential violations.

Requirement Two

Completion of the collection and organization of the necessary pipeline strength test records and pipeline features information for validation of the Maximum Allowable Operating Pressure for PG&E's gas transmission pipeline, consistent with the NTSB's recommendations for maintaining asset records to a "traceable, verifiable, and complete" requirement, and in accordance with CPUC Resolution L-410 (Jan. 13, 2011), Decision 11-06-017, and Decision 12-12-030.

Requirement Three

Confirmation of satisfactory strength testing of at least 500 miles of gas transmission pipelines in 2017 and 2018.

Requirement Four

Upgrading and/or retrofitting approximately 300 miles of gas transmission pipelines to accommodate in-line inspection tools in 2017 and 2018.

Requirement Five

Consistent with CPUC Decision 15-04-024, Appx E at 1 (San Bruno OII Remedy 4), implementation of Integrity Management procedures that ensure where data is missing, direct the Company to use conservative, supportable assumptions as required by ASME B31.8S.

Requirement Six

Consistent with CPUC Decision 15-04-024, Appx E at 1 (San Bruno OII Remedy 3), completion of records search to include gas transmission pipeline historical leak data into a single database of transmission leak record data.

Requirement Seven

Consistent with CPUC Decision 15-04-024, Appx. E at 1 (San Bruno OII Remedy 2), implementation of Integrity Management procedures sufficient to ensure that the data gathering processes, the data elements collected and reviewed, and company data sources meet the requirements of 49 CFR Part 192.917(b) and ASME B31.8S.

Requirement Eight

Consistent with NTSB Recommendation P-11-29, implementation of Integrity Management revisions to include (1) a revised risk model, reflecting actual recent data on leaks, failures, and incidents; (2) consideration of defect and leak data for the life of each pipeline; (3) revised risk methodology to ensure assessment methods are selected for each pipeline segment; and (4) improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered segment.

Requirement Nine

Implementation of policies and procedures that address threats caused by vegetation and structural encroachments on gas transmission pipelines.

Requirement Ten

Implementation of processes and procedures that for each segment of gas transmission line in High-Consequence Areas, enable PG&E to calculate the expected life of the pipe using a fracture control analysis that (1) estimates maximum flaw sizes remaining after inspections and/or strength testing; (2) estimates potential crack growth rate based on the past history of and potential pressure cycles; (3) assesses the remaining life calculations; and (4) determines appropriate methods of reassessment and frequency of reassessment of each such segment.

Requirement Eleven

Consistent with CPUC Decision 15-04-024, Appx. E at 2 (San Bruno OII Remedy 6), implementation of policies and procedures such that relevant data is incorporated in threat identification and assessment procedures for both covered and non-covered segments, including but not limited to potential manufacturing and construction threats, and leak data.

Requirement Twelve

Consistent with CPUC Decision 15-04-024, Appx. E at 2 (San Bruno OII Remedy 9), implementation of threat identification and assessment procedures such that High-Consequence Areas are prioritized consistent with 49 CFR Part 192.917(e)(3)-(4).

Requirement Thirteen

Implementation of policies designed to incorporate changed circumstances into assessment methodologies and prioritization, including Risk Management Procedure 16 ("Threat Identification") and TD 4810B-001 ("Changes to Integrity Management Pressure Testing Requirements for Unstable Manufacturing Threats"), consistent with ASME B31.8S.

Requirement Fourteen

Consistent with CPUC Decision 15-04-024, Appx. E at 2 (San Bruno OII Remedy 8), cessation of regularly increasing pipeline pressure up to a "system MAOP" to eliminate the need to consider manufacturing and construction threats, and analysis of segments that were subjected to the planned pressure increases to determine the risk of failure from manufacturing threats under 49 CRF Part 192.917(e)(3), including review of strength-testing of all segments identified as having an unstable manufacturing threat.

Requirement Fifteen

Consistent with CPUC Decision 15-04-024, Appx. E at 2 (San Bruno OII Remedy 10), implementation of threat identification and assessment policies and procedures such that cyclic fatigue and other loading conditions are incorporated into segment-specific threat assessments and risk ranking algorithm, including review of risk management procedures for appropriate treatment of cyclic fatigue and loading.

EXHIBIT 3: PG&E CONDITIONS OF PROBATION

April 3, 2019 Order, Dkt. 1040

- **Condition 1:** PG&E must fully comply with all applicable laws concerning vegetation management and clearance requirements, including Sections 4292 and 4293 of the California Public Resources Code, CPUC General Order 95, and FERC FAC-003-4.

- **Condition 2:** PG&E must fully comply with the specific targets and metrics set forth in its wildfire mitigation plan, including with respect to enhanced vegetation management. Compliance with these targets and metrics, however, will not excuse any failure to fully comply with the vegetation laws as required in paragraph 1.

- **Condition 3:** The Monitor shall assess PG&E's wildfire mitigation and wildfire safety work, including through regular, unannounced inspections of PG&E's vegetation management efforts and equipment inspection, enhancement, and repair efforts. The inspections will include both inspections of segments of power lines where PG&E has conducted its enhanced vegetation management efforts pursuant to its wildfire mitigation plan, as well as areas where enhanced vegetation management has yet to occur. The inspections will further include field interviews and questioning of PG&E employees and contractors.

- **Condition 4:** PG&E shall maintain traceable, verifiable, accurate, and complete records of its vegetation management efforts. PG&E shall report to the Monitor on the first business day of every month on its vegetation management status and progress, and make available for inspection all related records at the Monitor's request.

- **Condition 5:** PG&E shall ensure that sufficient resources, financial and personnel, including contractors and employees, are allocated to achieve the foregoing. If PG&E cannot find enough contractors, then PG&E must hire and train its own crews to trim and remove trees. To ensure that sufficient financial resources are available for this purpose, PG&E may not issue any dividends until it is in compliance with all applicable vegetation management requirements as set forth above.

May 14, 2019 Order, Dkt. 1070

- **Condition 6:** By no later than July 15, 2019, the PG&E Board of Directors, PG&E's Chief Executive Officer and certain other PG&E senior executive leaders, the Monitor, and Probation shall visit Paradise and San Bruno to gain a firsthand understanding of the harm inflicted on those communities and meet with victims and other stakeholders, such as fire-fighting personnel and/or city officials.

- **Condition 7:** A committee of the PG&E Board of Directors shall assume responsibility for tracking progress against PG&E's Wildfire Safety Improvement Plan, as approved by the California Public Utilities Commission, and the new terms of probation imposed on April 3 regarding wildfire safety. The committee is to report in writing to the Board at least quarterly, and also present orally to the Board at least quarterly, PG&E's progress in meeting the terms

of the approved Wildfire Safety Improvement Plan and the April 3 terms of probation and, to the extent there are shortfalls, how PG&E will address the shortfalls.

August 7, 2020 Order, Dkt. 1243

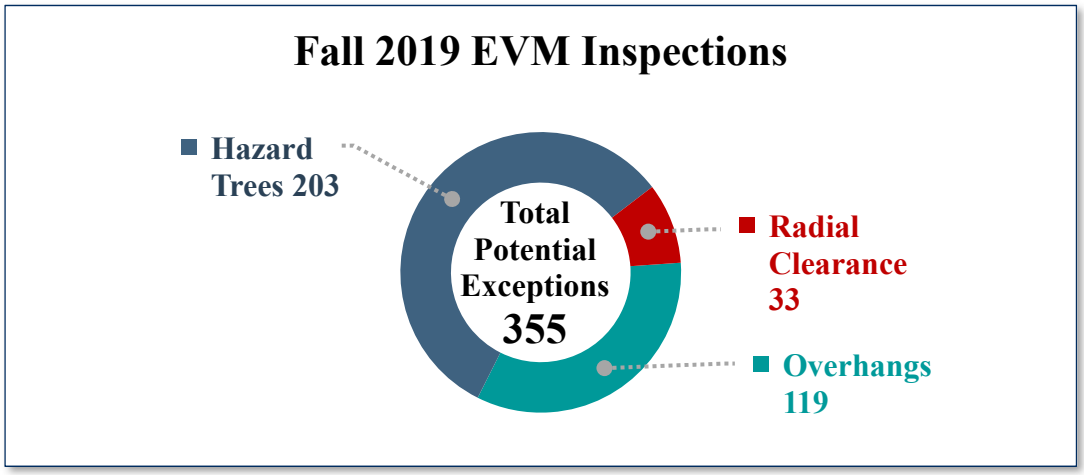
- **Condition 8:** Vegetation Condition: PG&E shall, by September 1, 2020, staff an in-house vegetation management inspection manager to oversee a number of workforce resources who will provide in-field oversight of all stages of the vegetation management process, including the enhanced vegetation management program work, to be deployed throughout PG&E's territory, including High Fire-Threat Districts (HFTDs). By the end of September 2020, PG&E will extend offers to 10 in-house field supervisors and/or inspectors, an additional 10 inspectors by the end of November, and the remaining approximately 10 inspectors by the end of January 2021. The inspectors shall conduct in-field oversight of PG&E contractors while the work is being performed, verifying and correcting any deviation from applicable scopes of work pursuant to PG&E policies and legal requirements. The inspectors shall also oversee pre-inspectors to help ensure they are clearly marking and designating trees for trimming and removal, and that tree-trimming contractors are appropriately performing their duties. Deviations from applicable scopes of work shall also be accurately recorded and reported to PG&E and the Monitor team to be used for, among other things, ongoing training of PG&E's contract workforce.

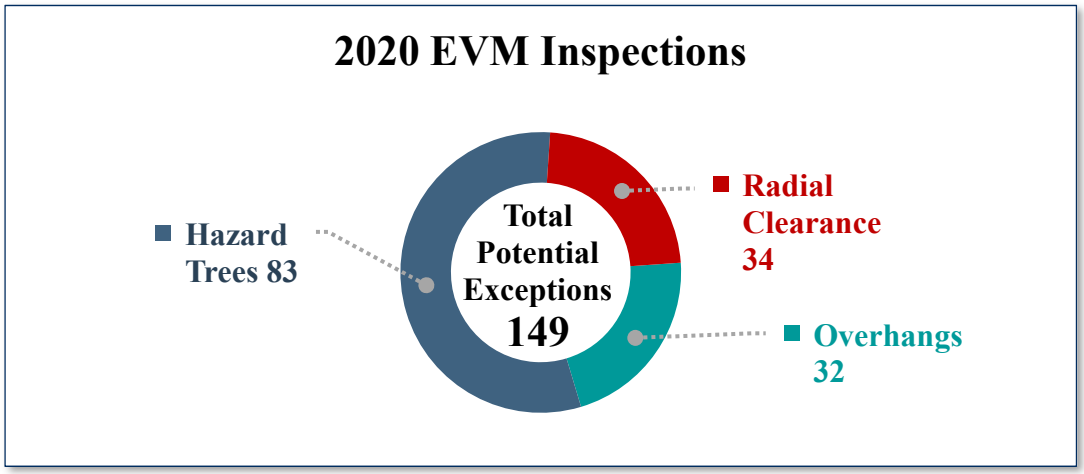
- **Condition 9:** Asset Age Condition: For certain critical transmission tower components in High Fire-Threat Districts, the failure of which may result in an ignition, PG&E shall conduct a reasonable search and, where available, record the age and date of installation of those components. For all other such critical transmission components and where asset-age records are not reasonably available, PG&E shall make conservative assumptions of such ages and dates of installation. PG&E shall also implement a program to determine the expected useful life of critical components factoring in field conditions and incorporate that information into its risk-based asset management programs. PG&E shall begin this effort (or supplement any existing or planned initiatives) immediately and provide monthly progress reports to the Monitor team.

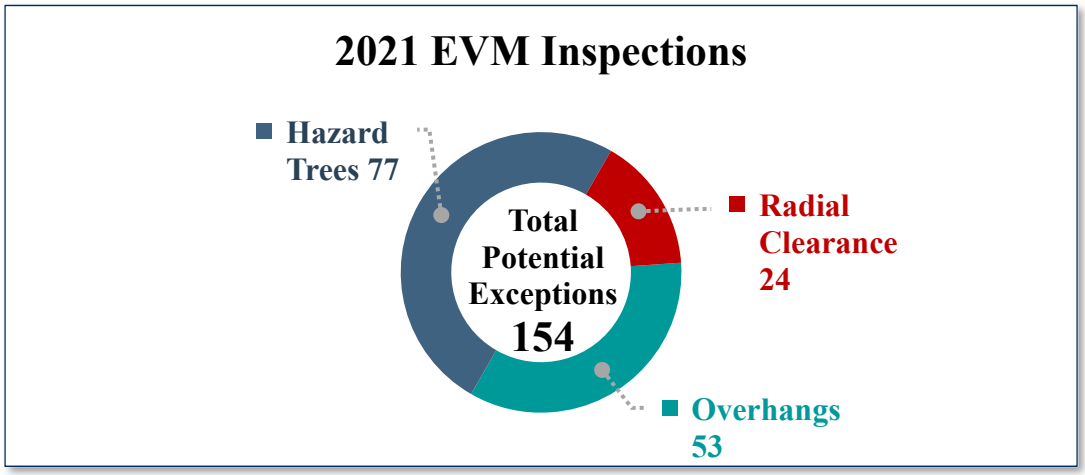
- **Condition 10:** Transmission Inspection Program Condition: PG&E shall, by the end of 2020, supplement its transmission-asset inspections program to include the following measures: (1) hire a crew of in-house and/or contract inspectors, independent from inspectors conducting transmission inspections, to oversee in the field transmission inspections while they are being conducted; (2) going forward, and subject to CAISO clearances and/or other external dependencies, revise the material loss threshold for the replacement of cold-end hardware (including C-hooks and hanger plates) in HFTDs to create a 90-day replacement requirement for such hardware with an observed material loss approaching 50%; and (3) make the prior two years of inspection reports available to transmission post-inspection review teams starting in 2021, and one year of inspection reports available in 2020.

EXHIBIT 4: EVM INSPECTION STATISTICS

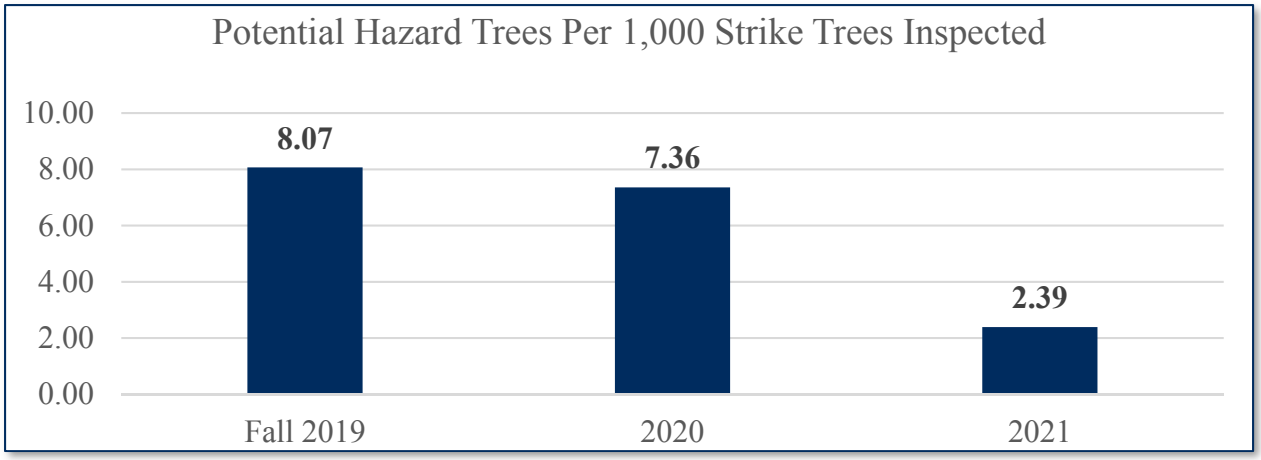
For Monitor team inspections of EVM areas from 2019-2021, the three graphs below show the number of potential exceptions observed.

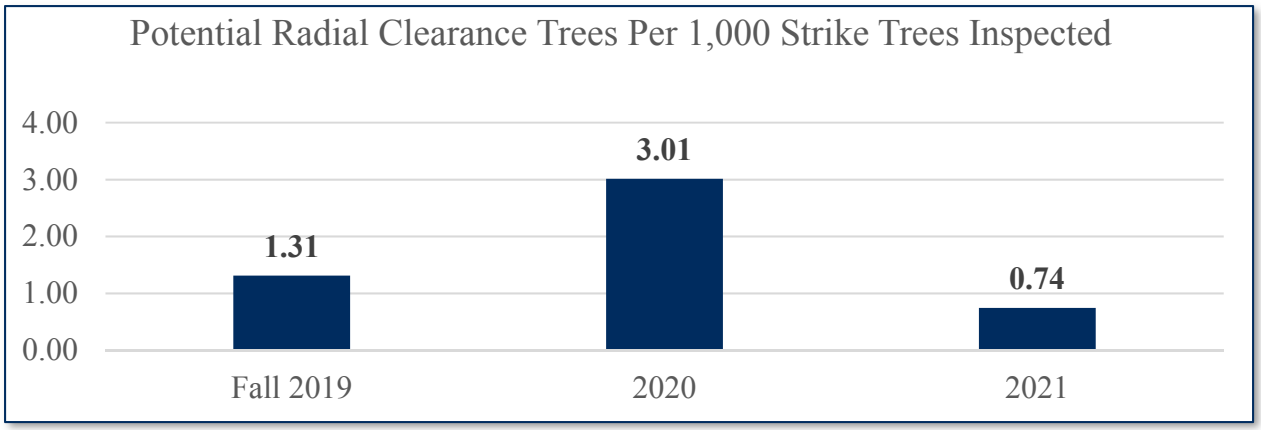






For Monitor team inspections of EVM areas from 2019-2021, the first graph shows the number of potential hazard trees observed per 1,000 strike trees inspected, the second graph shows the number of potential radial clearance issues observed per 1,000 strike trees inspected, and the third graph shows the number of potential overhang trees observed per 1,000 strike trees inspected.





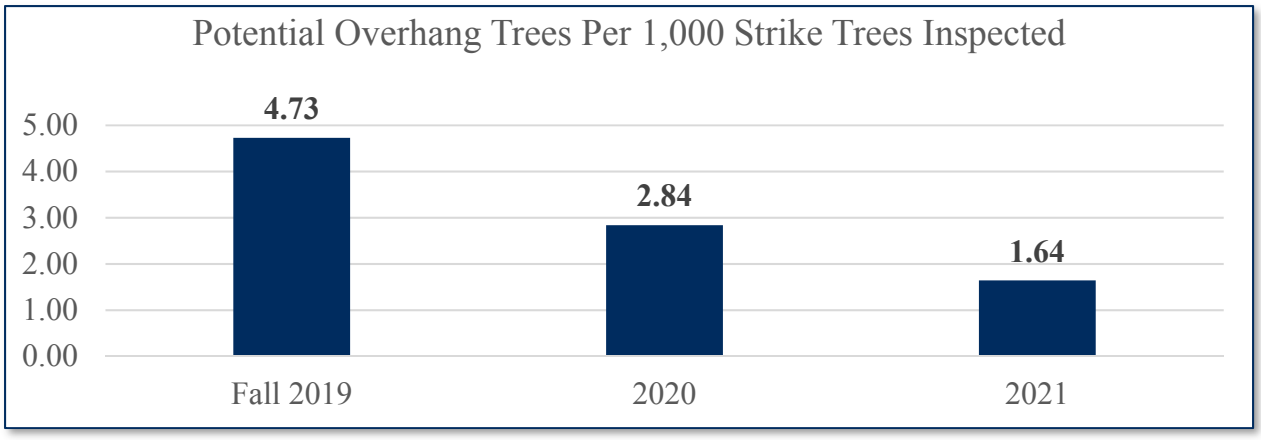
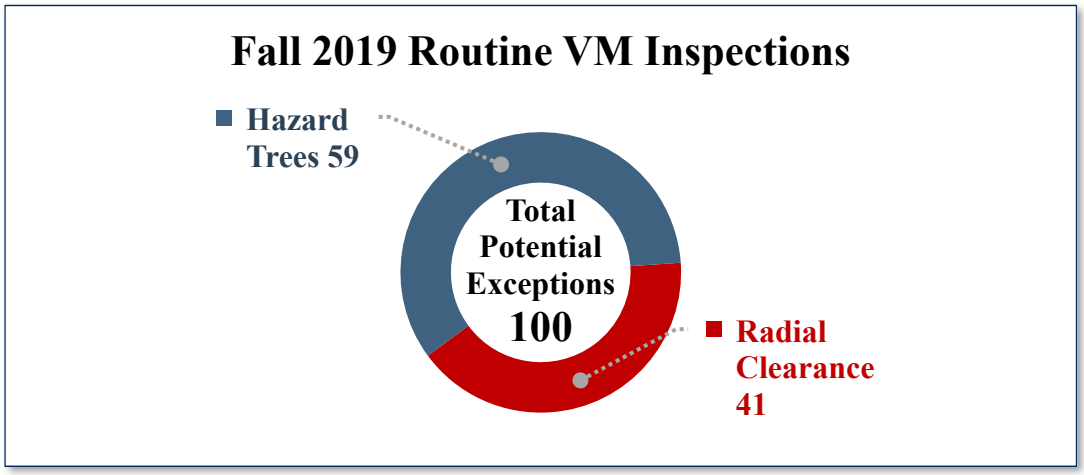
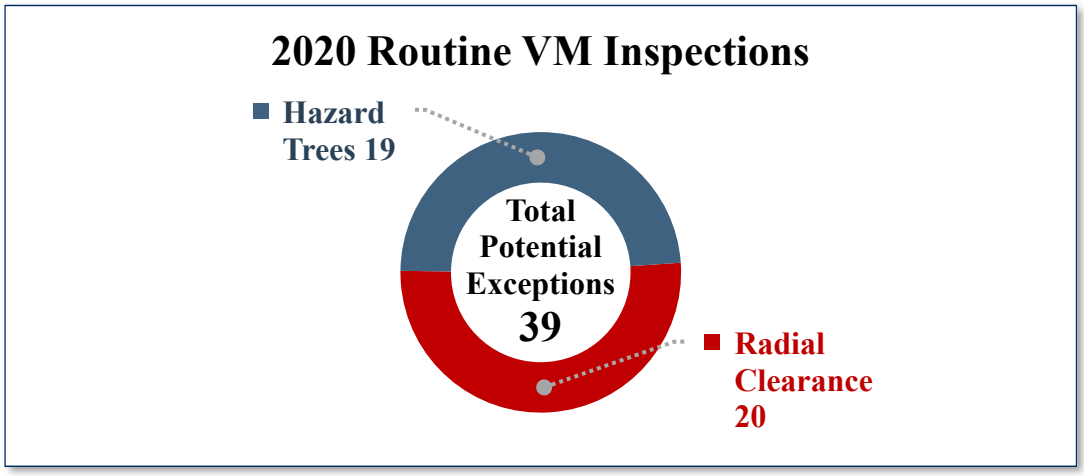
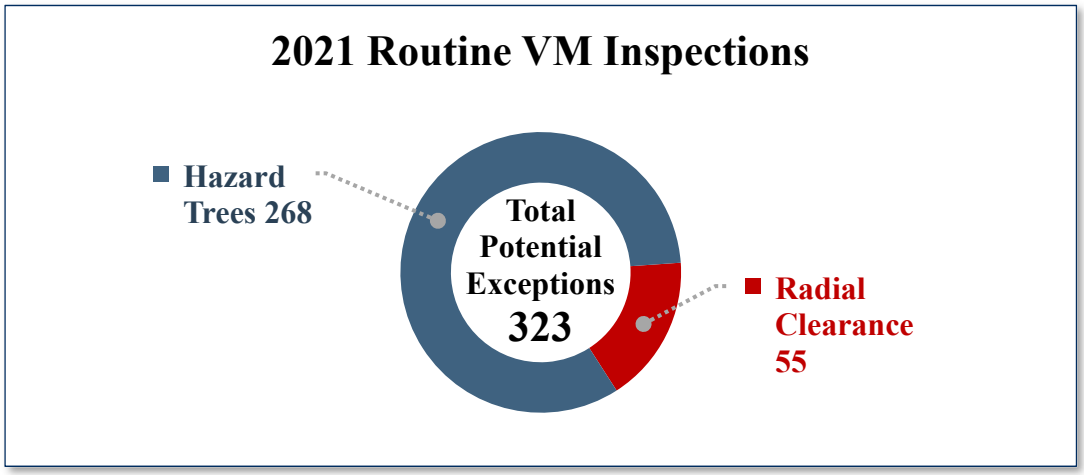


EXHIBIT 5: ROUTINE VM INSPECTION STATISTICS

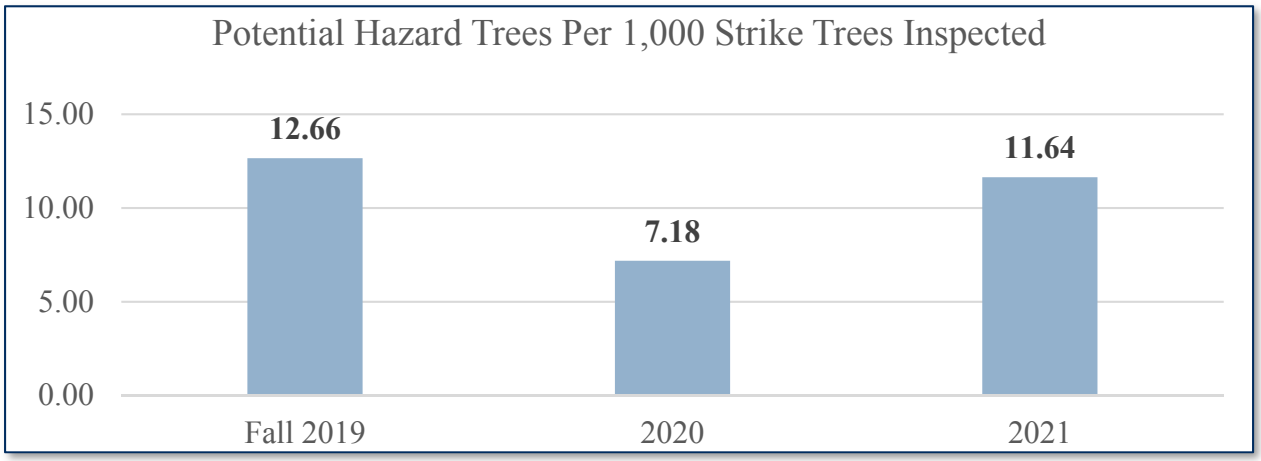
For Monitor team inspections of Routine VM areas from 2019-2021, the three graphs below show the number of potential exceptions observed.







For Monitor team inspections of Routine VM areas from 2019-2021, the first graph shows the number of potential hazard trees observed per 1,000 strike trees inspected, and the second graph shows the number of potential radial clearance issues observed per 1,000 strike trees inspected.



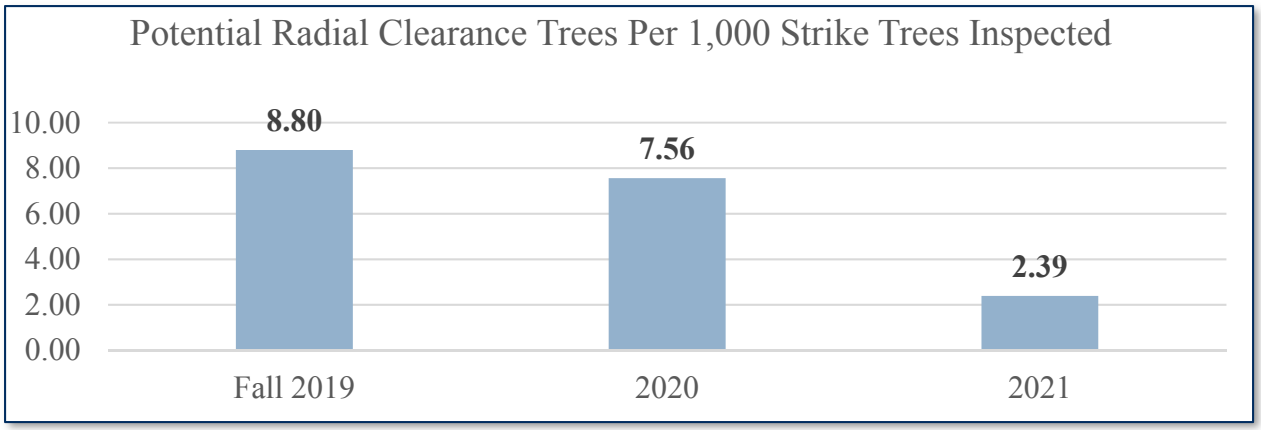


EXHIBIT 6: HAZARD TREES

Below is a hazard tree with fire damage identified by the Monitor team.





Below is a hazard tree that was dead or dying identified by the Monitor team.





Below is a hazard tree with decayed cavities identified by the Monitor team.



Below is a hazard tree with poor taper identified by the Monitor team.



Below is a hazard tree with branch dieback and decayed cavities identified by the Monitor team.





Below is a hazard tree with exposed roots identified by the Monitor team.



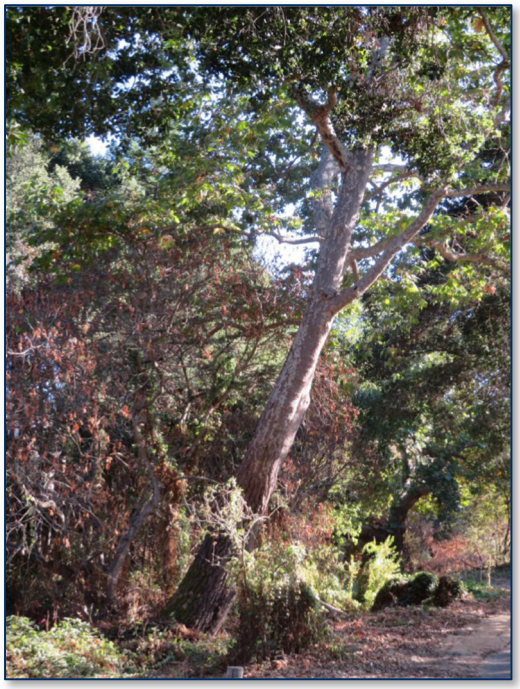


Below is a hazard tree with mechanical damage identified by the Monitor team





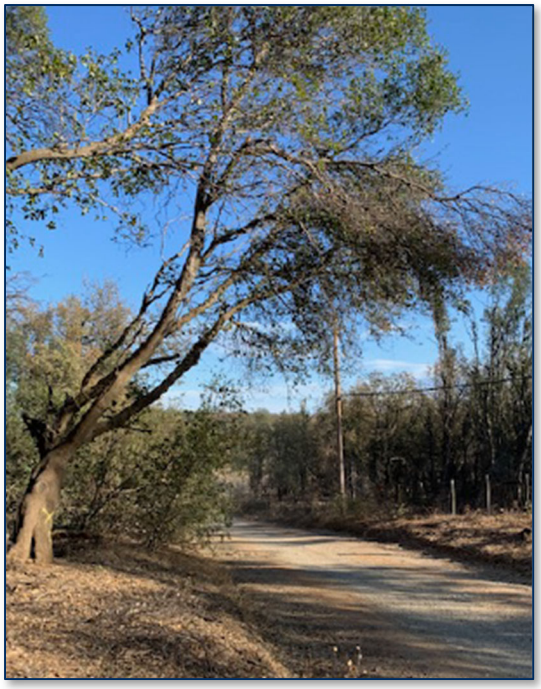
Below is a hazard tree uprooting at the base identified by the Monitor team.





Below is a hazard tree with cavities, heart rot, and cracking identified by the Monitor team.





Below is a hazard tree with cavities and rotting identified by the Monitor team.





Below is a hazard tree with severe lean towards primary conductor identified by the Monitor team.





EXHIBIT 7: VM RISK PRIORITIZATION STATISTICS

The chart below shows the percentage of EVM mileage in 2019-2021 completed in the top 10% of risk-ranked HFTD circuit miles, according to PG&E's stated risk models in those years.

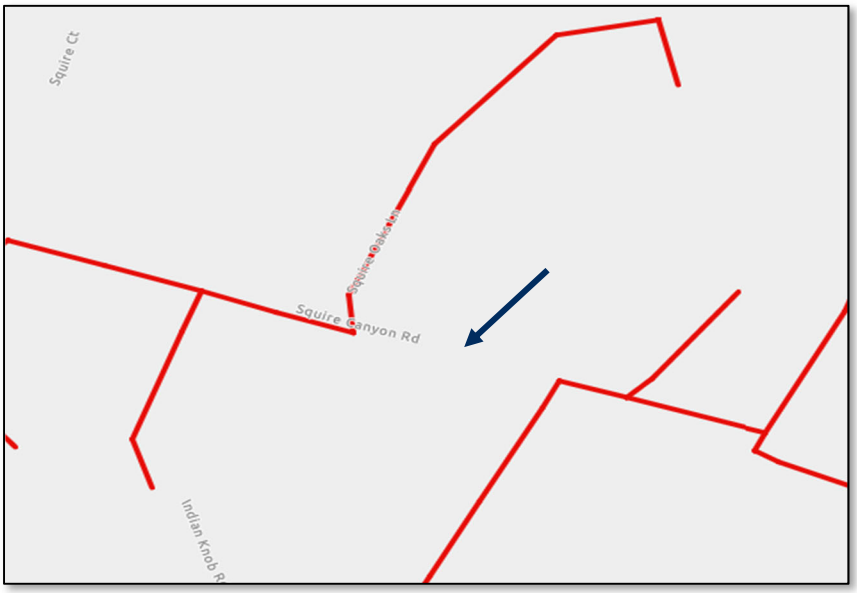
	2019	2020	2021 YTD
Total EVM Work Verification Pass Miles	2,499.29	1,877.94	1,303.96
EVM Work Verification Pass Miles Within the Top 10% of HFTD Miles on the Stated Risk Model	463.94	118.93	1,079.83
Percentage of EVM Work Verification Pass Miles Within the Top 10% of HFTD Miles on the Stated Risk Model	18.6%	6.3%	82.8%

EXHIBIT 8: VM MAP INACCURACIES

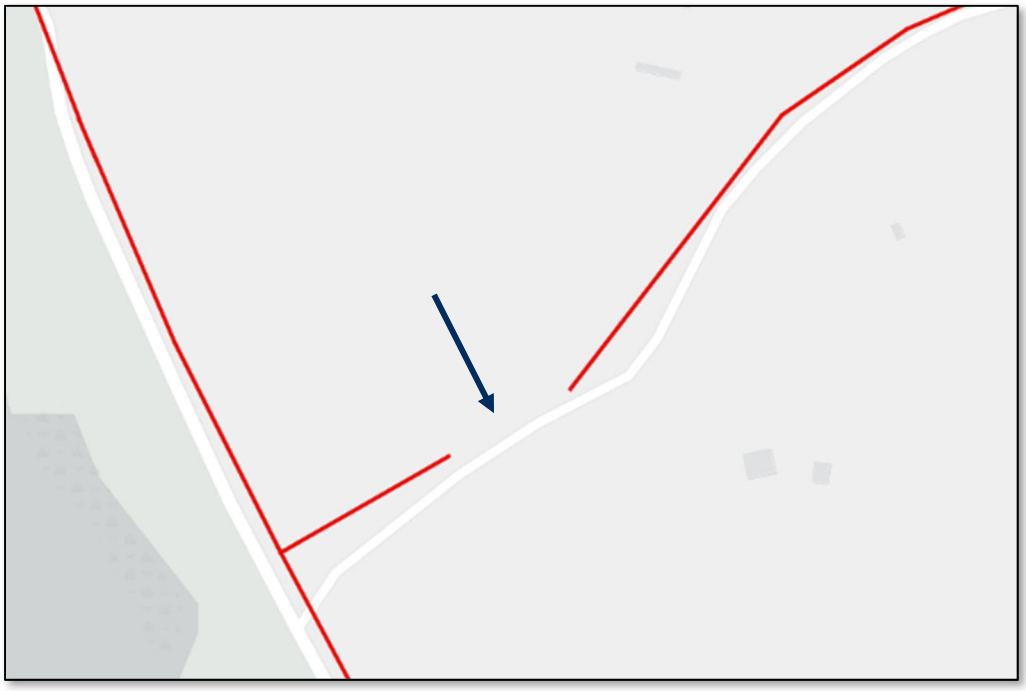
On CIP_BF126-A14_638206, the actual location of a pole (blue circle with white arrow) was ~200 feet away from the location of that pole on the Arc Collector map (red circle).



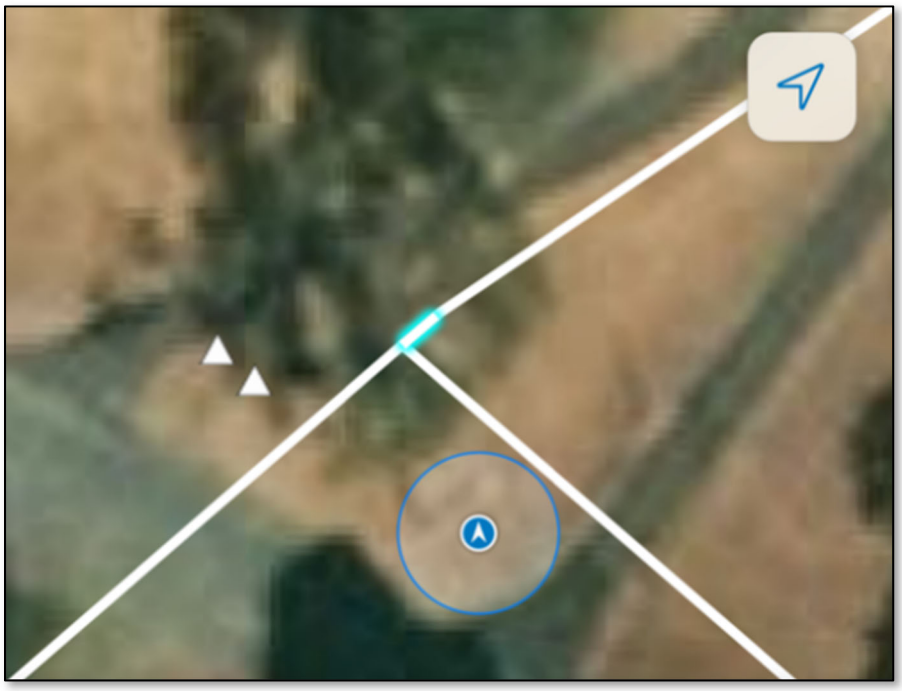
Near CIL_AY138-L08_143892, the Monitor team informed PG&E on 10/30/20 of a radial clearance issue on a segment that was missing from the Arc Collector map. That segment is still missing in 2021.



Near CIE_AJ120-I16_1746168, a segment was observed as missing from the Arc Collector map.



CIE_B127-B19_1727589 is a seven-foot long segment that does not correspond to a full span of primary conductor.



CIE_AO108-B15_1774125 (and the adjacent L-shaped segment) do not exist in the field.



CIE_AP120-K24_1757184 appears curved on Arc Collector, but the segment is a straight line in the field.

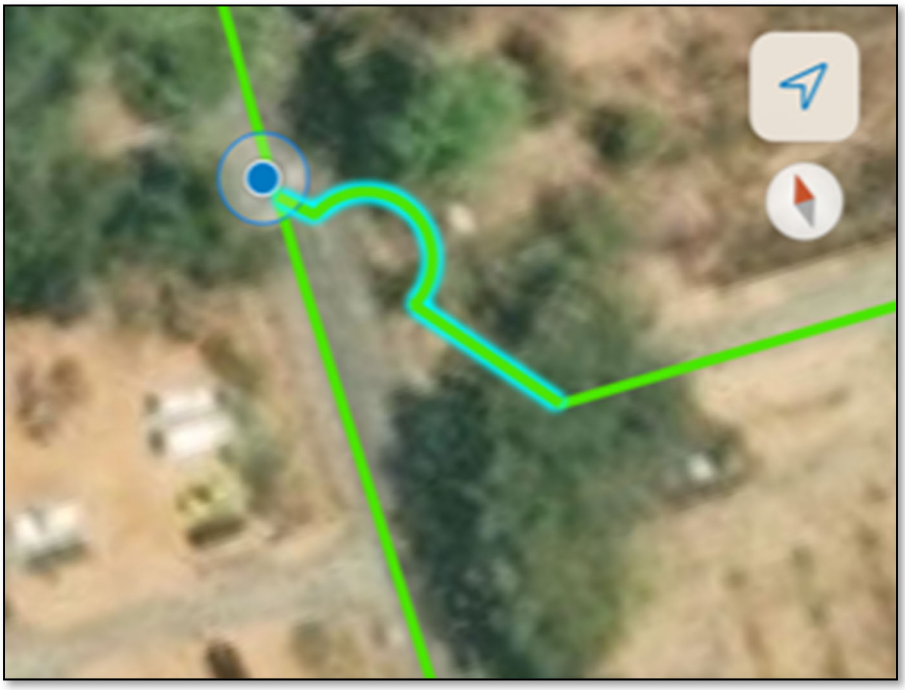
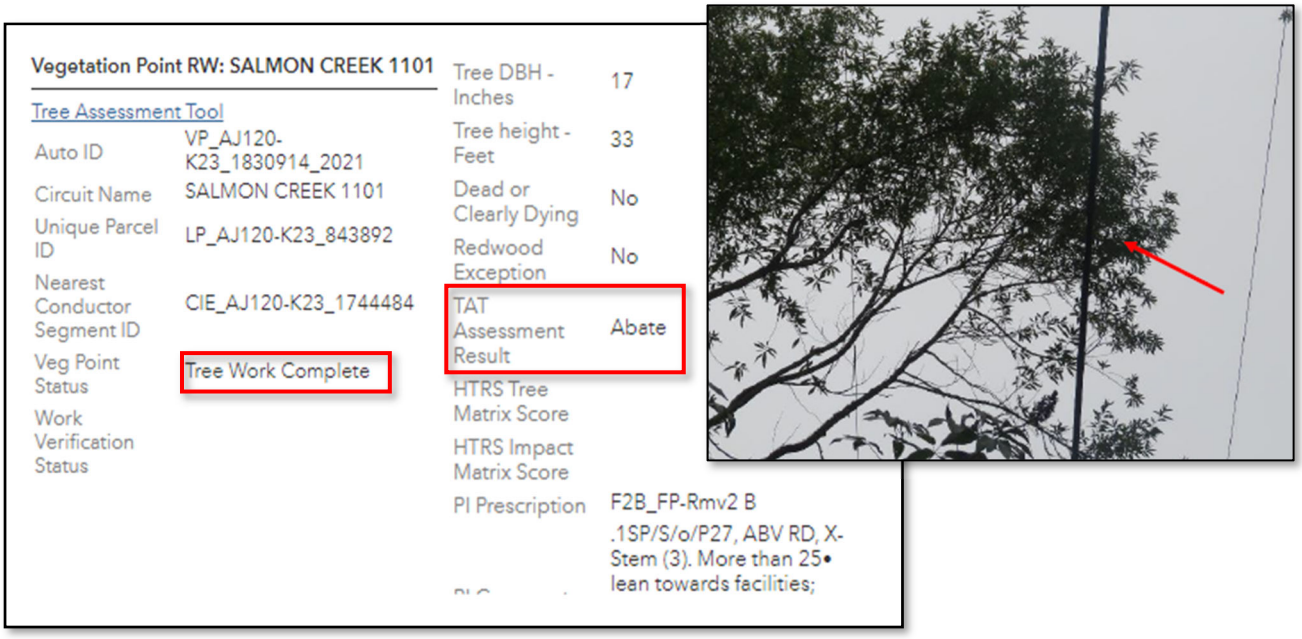


EXHIBIT 9: INCONSISTENT VM DATA

Near CIE_AJ120-K23_1744484, the Monitor team observed five trees that had been marked as "Tree Work Complete," but the Monitor team observed that the prescribed tree work had not been performed.

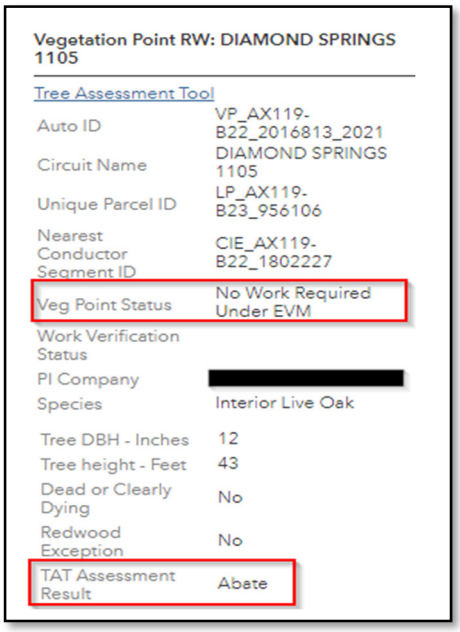


Vegetation Point RW: SALMON CREEK 1101

Tree Assessment Tool

Auto ID	VP_AJ120-K23_1830914_2021	Tree DBH - Inches	17
Circuit Name	SALMON CREEK 1101	Tree height - Feet	33
Unique Parcel ID	LP_AJ120-K23_843892	Dead or Clearly Dying	No
Nearest Conductor Segment ID	CIE_AJ120-K23_1744484	Redwood Exception	No
Veg Point Status	Tree Work Complete	TAT Assessment Result	Abate
Work Verification Status		HTRS Tree Matrix Score	
		HTRS Impact Matrix Score	
		PI Prescription	F2B_FP-Rmv2 B .1SP/S/o/P27, ABV RD, X-Stem (3). More than 25• lean towards facilities;

The below vegetation point record shows a tree with a Tree Assessment Tool result of "Abate" but a Status of "No Work Required Under EVM." The map shows 1,541 vegetation point records in Arc Collector with the same discrepancy between the Tree Assessment Tool result and the Status.



Vegetation Point RW: DIAMOND SPRINGS 1105

Tree Assessment Tool

Auto ID	VP_AX119-B22_2016813_2021
Circuit Name	DIAMOND SPRINGS 1105
Unique Parcel ID	LP_AX119-B23_956106
Nearest Conductor Segment ID	CIE_AX119-B22_1802227
Veg Point Status	No Work Required Under EVM
Work Verification Status	
PI Company	[redacted]
Species	Interior Live Oak
Tree DBH - Inches	12
Tree height - Feet	43
Dead or Clearly Dying	No
Redwood Exception	No
TAT Assessment Result	Abate

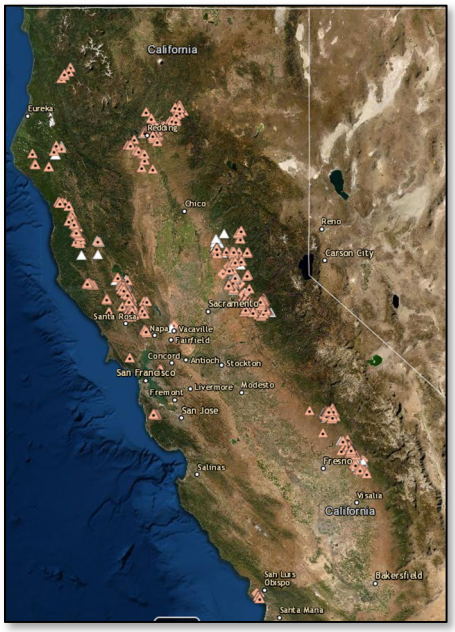
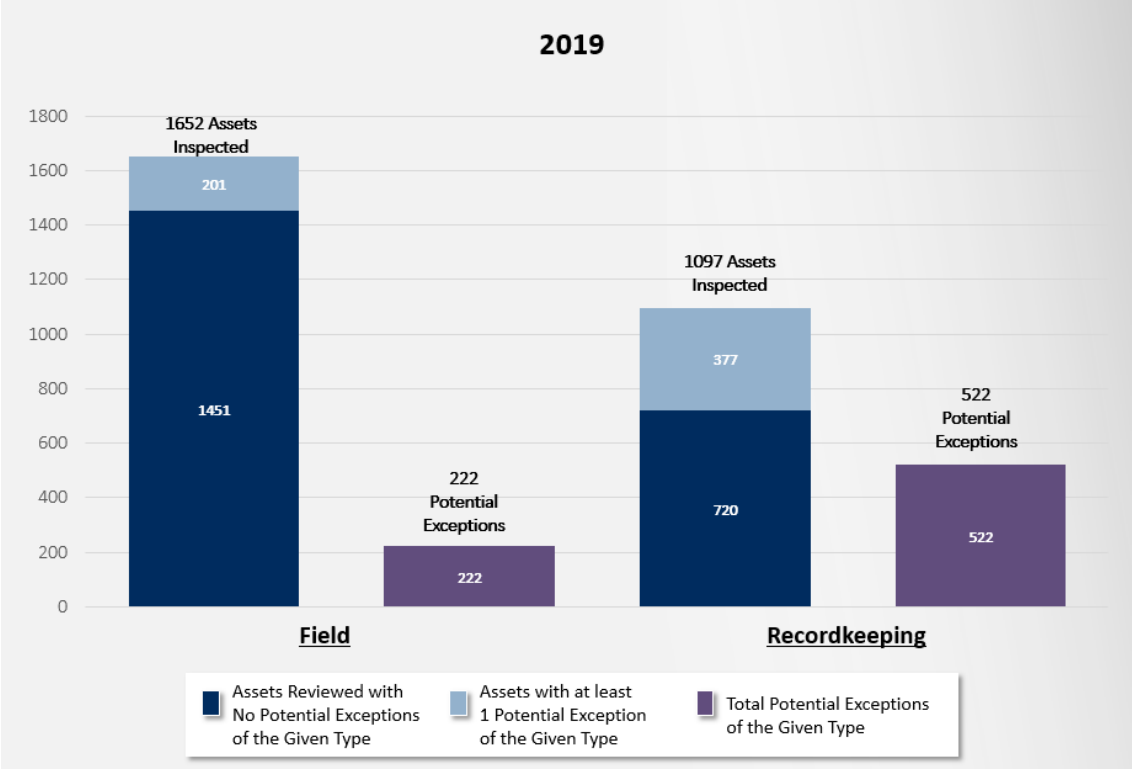
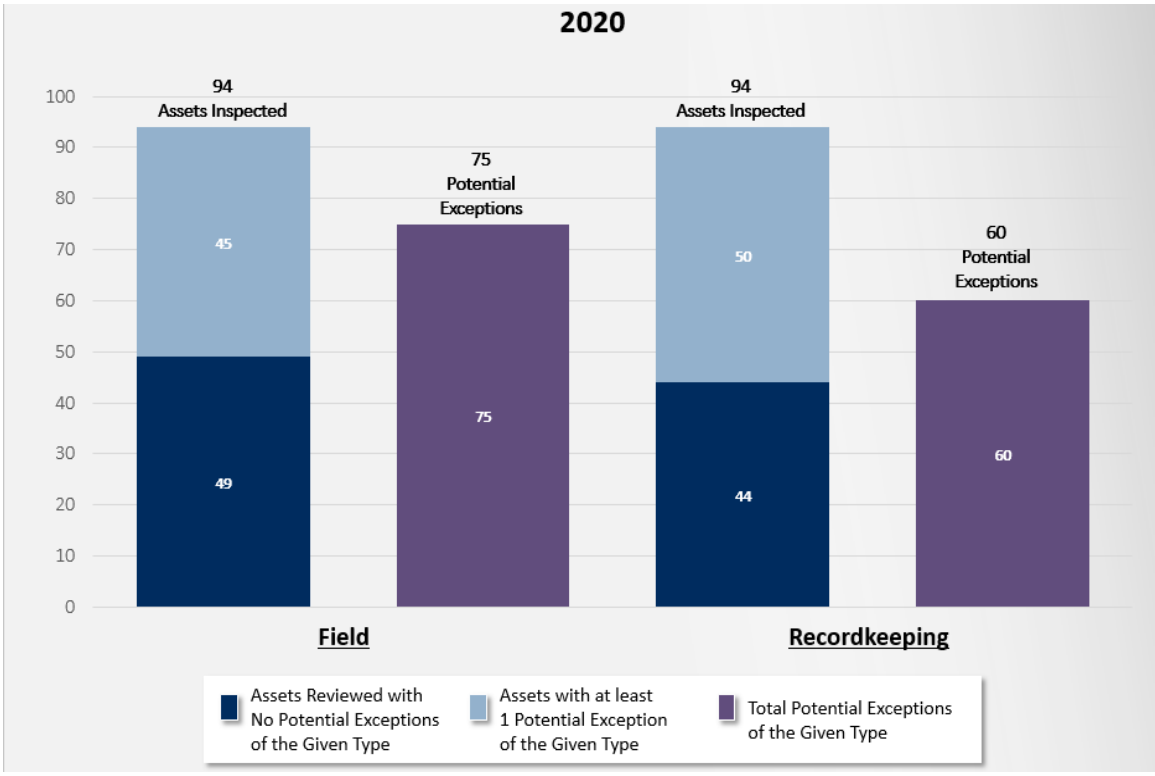
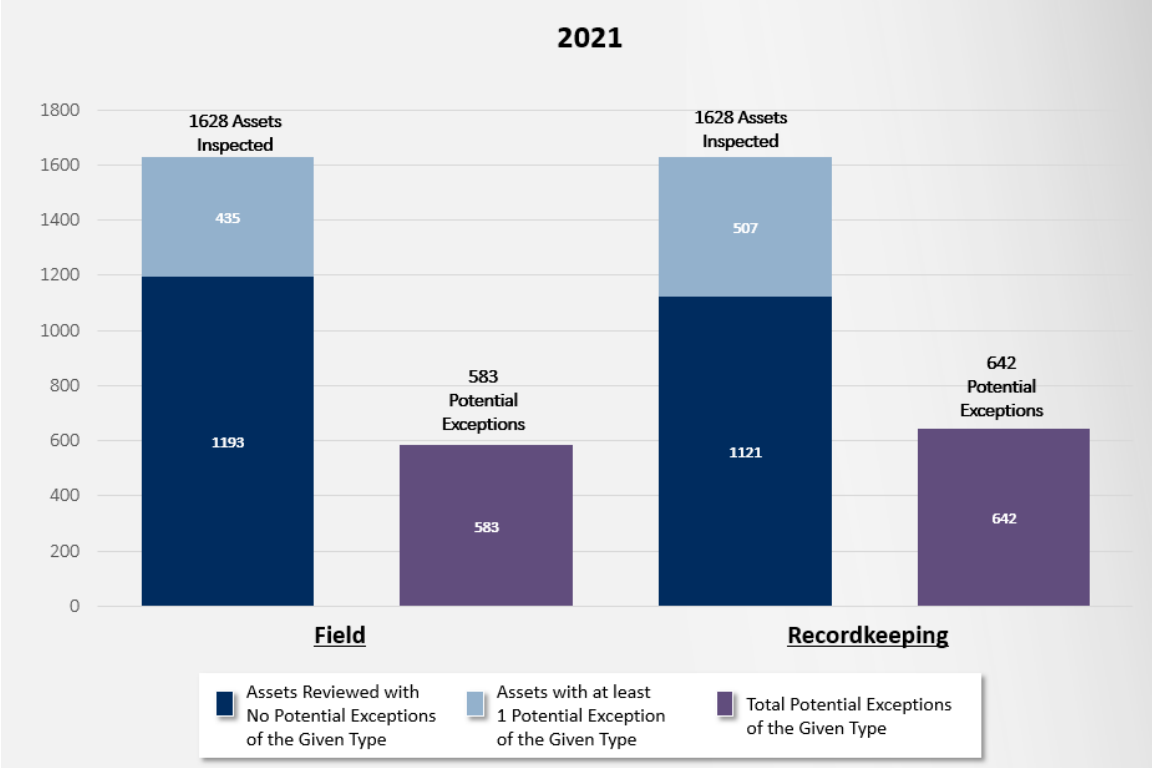


EXHIBIT 10: REVIEW OF DISTRIBUTION INSPECTION FINDINGS (2019 - 2021)

The graphics below show the number of distribution inspections reviewed by the Monitor team each year, as well as the number of potential exceptions recorded.




2020
94
Assets Inspected
45
49
75
Potential
Exceptions
75
94
Assets Inspected
50
44
60
Potential
Exceptions
60
100
90
80
70
60
50
40
30
20
10
0
Field
Recordkeeping
Assets Reviewed with No Potential Exceptions of the Given Type
Assets with at least 1 Potential Exception of the Given Type
Total Potential Exceptions of the Given Type


2021
1628 Assets
Inspected
435
1193
583
Potential
Exceptions
583
1628 Assets
Inspected
507
1121
642
Potential
Exceptions
642
1800
1600
1400
1200
1000
800
600
400
200
0
Field
Recordkeeping
Assets Reviewed with No Potential Exceptions of the Given Type
Assets with at least 1 Potential Exception of the Given Type
Total Potential Exceptions of the Given Type

The tables below show the number of potential exceptions recorded by the Monitor team for the most prevalent field conditions (i.e., those that should have been identified by an inspector per PG&E guidance) on distribution structures.

Top Field Conditions - 2019

Condition	# of Conditions Identified
Poles: Is pole damaged, broken, burnt, or showing signs of cracking or decay?	50
Guys/Anchors: Is guy/anchor broken, damaged, corroded, covered by vegetation, or overgrown; or is soil eroded, or guy/anchor graded or buried; or is there strain or abrasion?	36
Tree/Vine: Is there improper clearance on conductor, pole or cross arm due to vegetation?	28
Connector: Are mini-wedge or Insulink connectors used in primary conductors? Or is there an incorrect use of secondary connectors (mini-wedge or Insulink) in primary conductor?	14
Guys/Anchors: Does pole have any unbalanced or unsupported strain at primary or communication level? Are necessary guys missing or loose?	13

Top Field Conditions - 2020

Condition	# of Conditions Identified
Conductor: Conductor has splices tied in within 2' of insulator preventing free movement of splice with conductor	18
Structure: Pole broken, damaged, burnt, deformed, corroded, gunshot, or showing signs of cracking, rotten or decay	8
Anchor and Guys: Guy wire broken, damaged, clearance issues, corroded, covered by vegetation, overgrown, strain or abrasion	8
Hardware and Framing: Hardware Framing molding missing, broken, damaged, or loose	4
Vegetation: Tree causing strain or abrasion to secondary or service	4

Top Field Conditions - 2021

Condition	# of Conditions Identified
Structure: Pole broken, damaged, burnt, deformed, corroded, gunshot, or showing signs of cracking, rotten or decay	164
Vegetation: Support Structure with non-exempt equipment, has dried ground vegetation within 10' radius of Support Structure base	55
Conductor: Conductor has splices tied in proximity to insulator preventing free movement of splice with conductor	53
Anchor and Guys: Guy wire broken, damaged, clearance issues, corroded, covered by vegetation, overgrown, strain or abrasion	37
Hardware and Framing: Tap clamps installed incorrectly	34

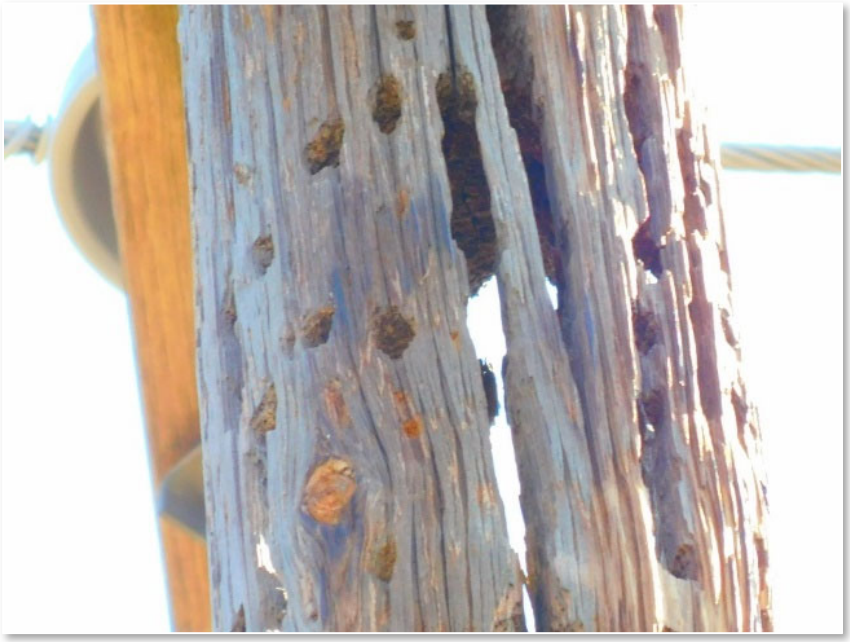
The graphics below show conditions identified by the Monitor team in its review of distribution inspections.

Below is a severely damaged crossarm the Monitor encountered in a Tier 3 HFTD. The Monitor team immediately reported this condition to PG&E, which then dispatched a field team that arrived on site within approximately two hours.



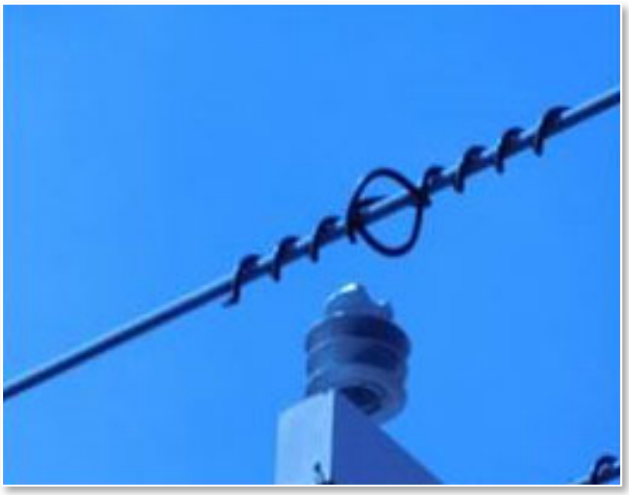
Below is a pole with severe cracking and decay that the Monitor team found in a Tier 2 area and immediately reported to PG&E. The Monitor team confirmed that PG&E replaced the pole the same day.





Below are floating conductors the Monitor team identified in Tier 3 areas and immediately reported to PG&E.

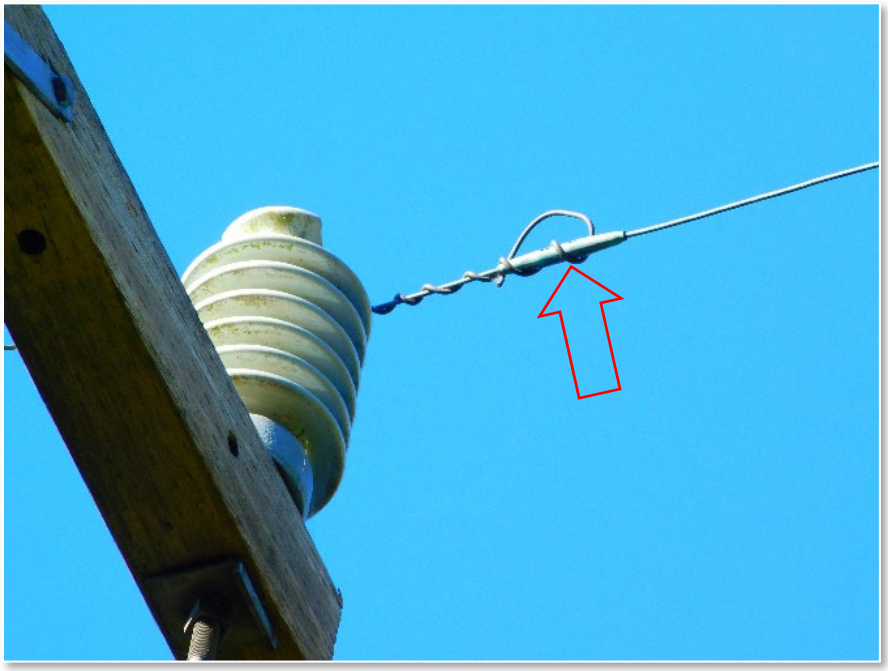






Below are conductors the Monitor team identified with splices tied in within 2’ of an insulator.





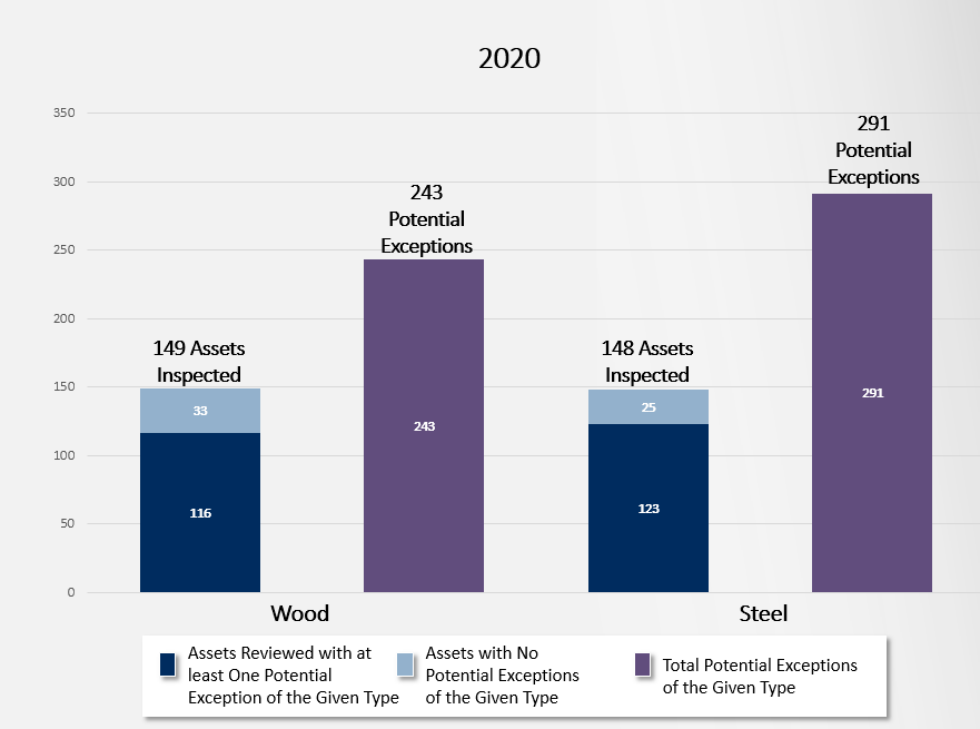
Below are examples found by the Monitor team where the guy wire was overgrown by vegetation.

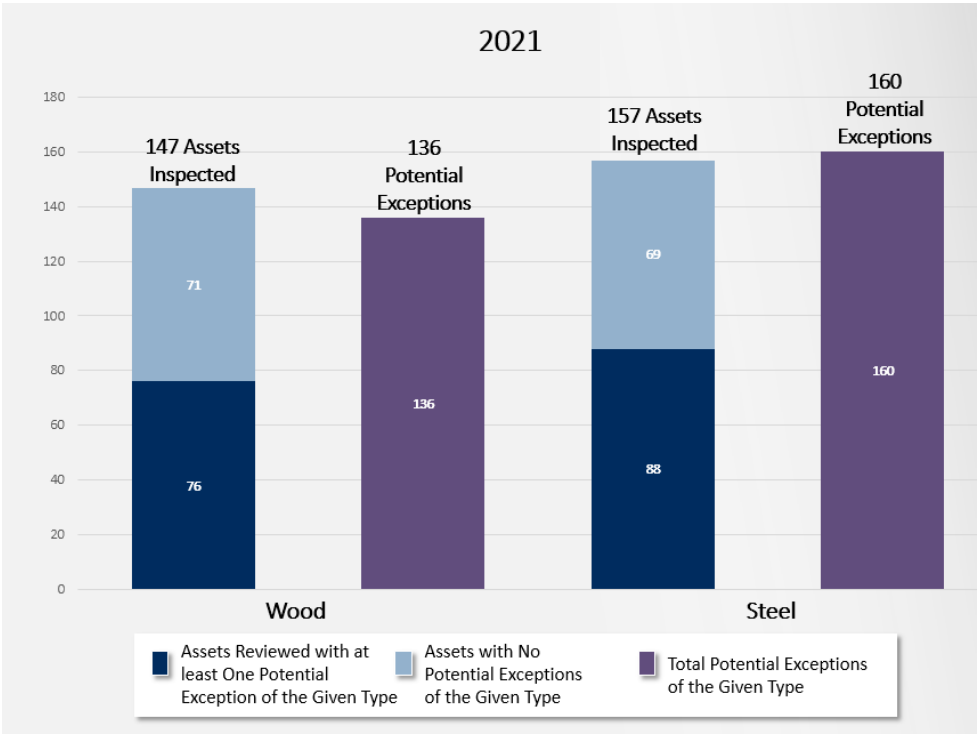




EXHIBIT 11: REVIEW OF TRANSMISSION INSPECTION FINDINGS (2020 - 2021)

The graphic below shows the number of transmission inspections reviewed by the Monitor team each year, as well as the number of potential exceptions recorded.





The tables below show the number of potential exceptions recorded by the Monitor team for the most prevalent conditions in transmission steel and wood structures in 2020 and 2021.

Top Steel Structure Conditions - 2020

Condition	# of Conditions Identified
Structure Location: Is the structure in a rural area and within 600 ft of a frequently traveled road/trail?	68
Structure Location: Is the structure in a rural area and within 600 ft of a dwelling or camp?	31
Steel Structure: Steel Structure Hardware Loose or missing	18
Insulators: Insulators' hardware cold-end in poor condition (e.g. C-hook)	17
Steel Structure: Insulator hanger (eye) plate in poor condition	13

Top Steel Structure Conditions - 2021

Condition	# of Conditions Identified
General: Rural area and structure within 600 ft of a frequently traveled road/trail	23
Conductors & Insulators: Is there OPGW or Shield Wire Present?	21
Steel Structure: Steel Structure hardware loose or missing (e.g vibrating members)	9
General: Vegetation present?	7
General: High voltage signs missing, damaged, or installed incorrectly (see E.D. 022168 further details see GO 95)	7

Top Wood Structure Conditions - 2020

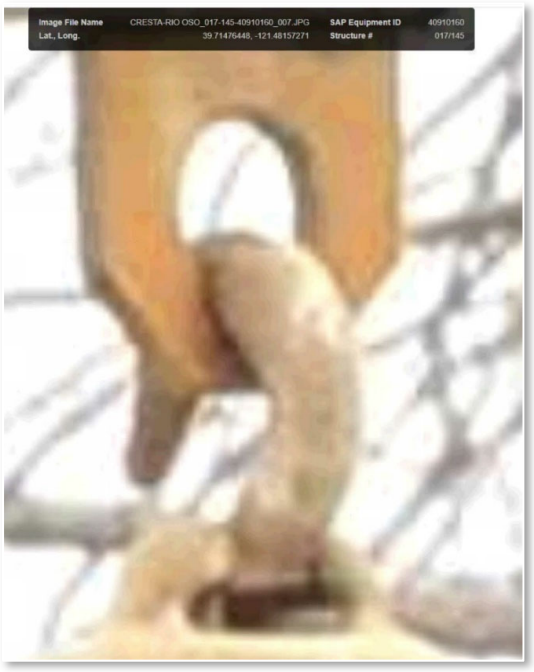
Condition	# of Conditions Identified
Structure Location: Is the structure in a rural area and within 600 ft of a frequently traveled road/trail?	58
Structure Location: Is the structure in a rural area and within 600 ft of a dwelling or camp?	31
Non-Steel Structure: Pole-top damage or split-top	22
Non-Steel Structure: Breaks or cracks or split in pole	18
Non-Steel Structure: Bird, animal or insect damage (e.g., woodpecker)	12

Top Wood Structure Conditions - 2021

Condition	# of Conditions Identified
General: Rural area and structure within 600 ft of a frequently traveled road/trail	29
General: Rural area and within 600 feet of a dwelling or camp	11
Non-Steel Structure: Does this structure have a guy?	11
General: High voltage signs missing, damaged, or installed incorrectly (see E.D. 022168 further details see GO 95)	10
Conductors & Insulators: Polymer	7
General: Distribution underbuilt present	7

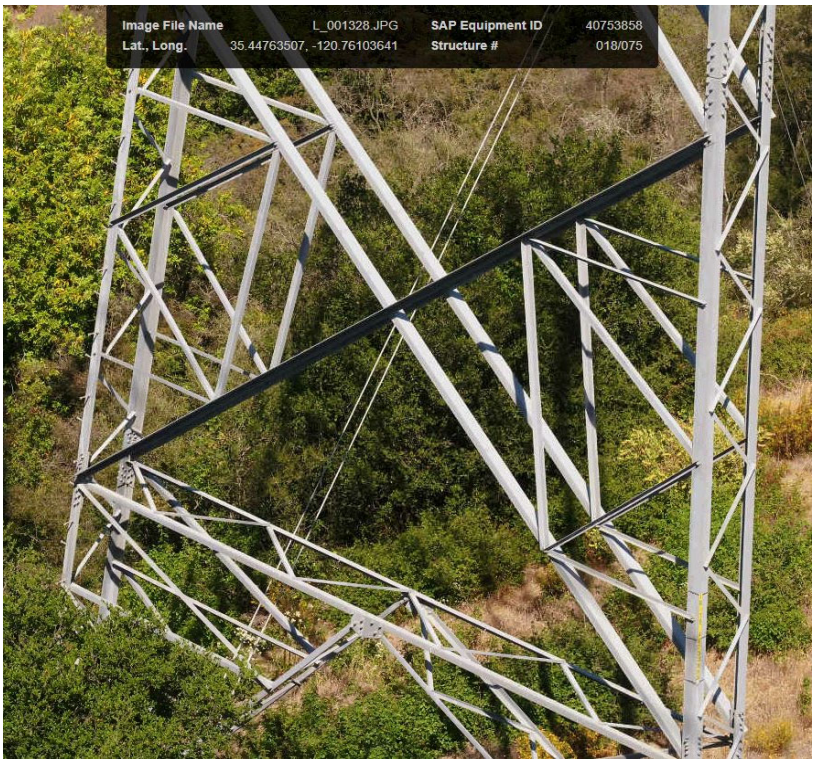
The graphics below show conditions identified by the Monitor team in its review of transmission inspections.

Below is a transmission structure on which the Monitor team observed a partially deteriorated C-hook and hanger plate.





Below are structures the Monitor team identified that appeared to have vegetation present where PG&E inspectors did not note it.



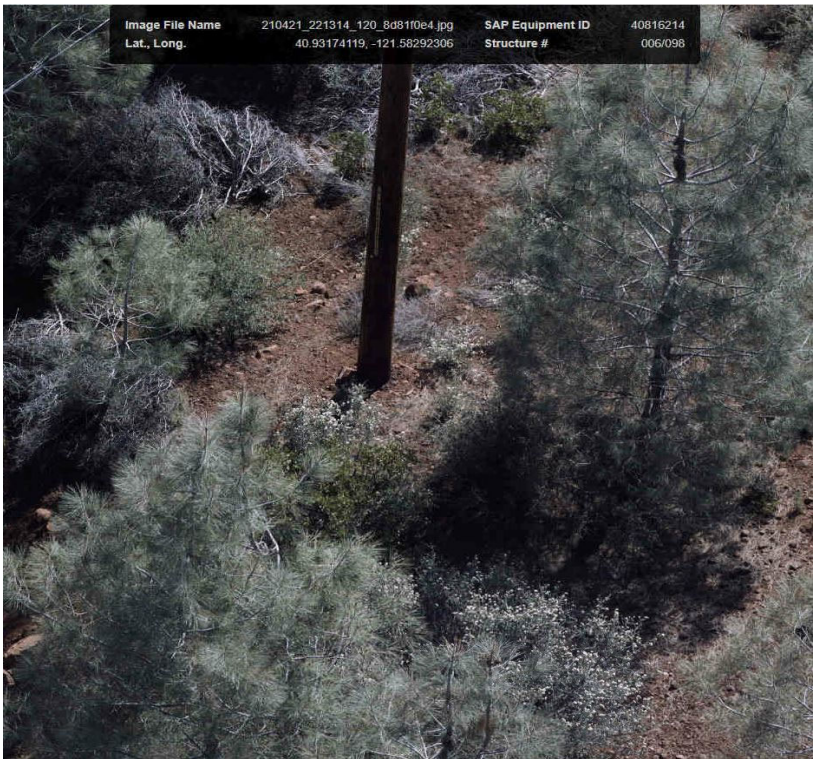


EXHIBIT 12: INCREASING BACKLOG OF INFRASTRUCTURE-RELATED REMEDIATION WORK

This graphic shows the increasing backlog of outstanding transmission and distribution tags through June 2021.

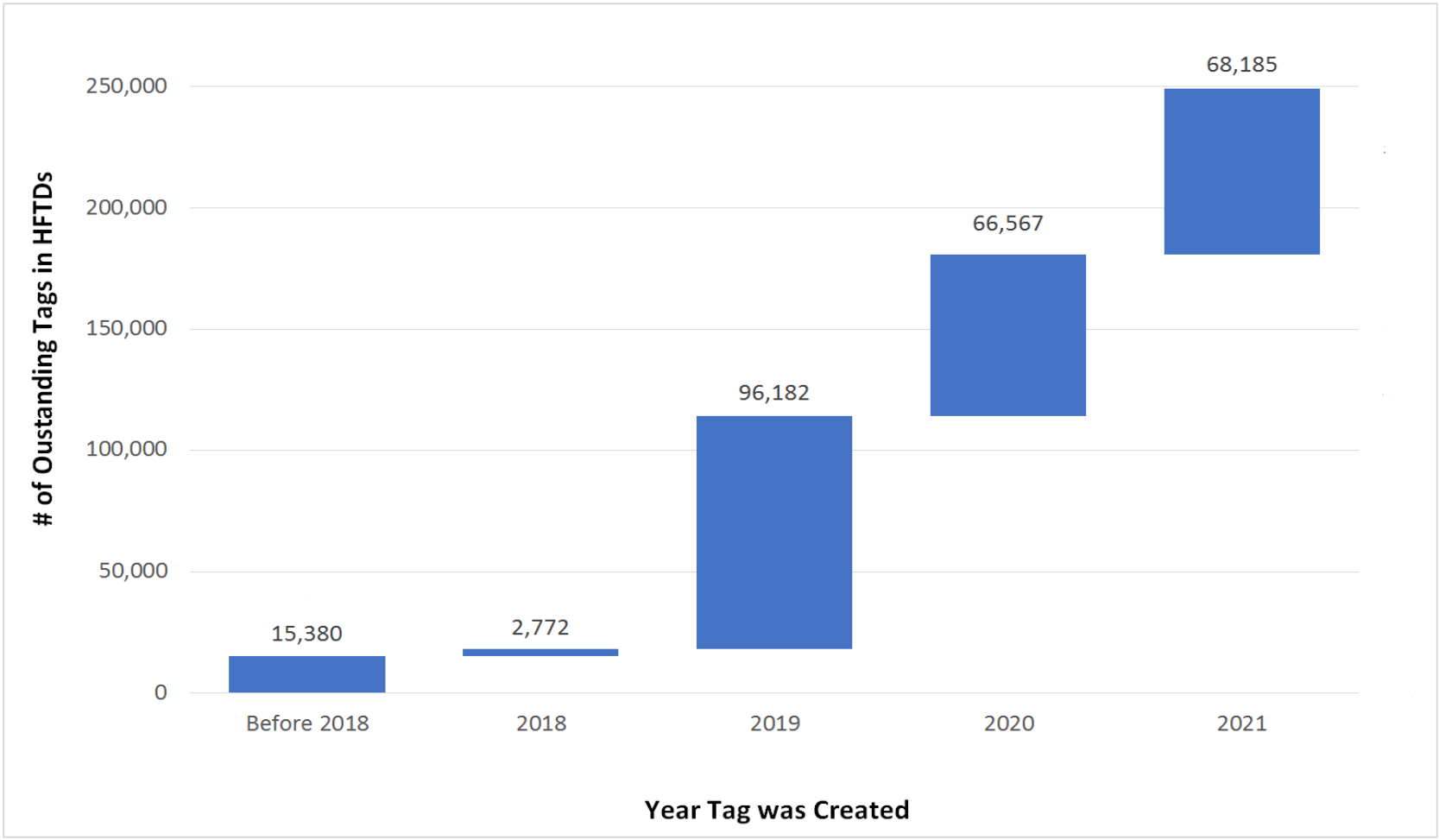


EXHIBIT 13: PENDING, UNRESOLVED INFRASTRUCTURE-RELATED TAGS

This table shows the pending, unresolved ("open") tags by repair tag priority that had not been addressed by June 30, 2021. Priority A tags are generated for conditions that require immediate mitigation and a full repair within 30 days. Priority B tags must be remediated within 90 days. Priority E and F tags must be remediated within one year (six months if in HFTD Tier 3) and five years, respectively. Priority H tags, which are only in distribution, refer to tags related to system hardening or proactive removal projects. WSIP refers to PG&E's 2019 Wildfire Safety Inspections Program, which was an accelerated ignition-based inspection program that evaluated every PG&E asset in areas of extreme (Tier 3) and elevate (Tier 2) wildfire risk, as defined by the CPUC HFTD map. Therefore, WSIP tags refer to tags identified through WSIP as opposed to PG&E's subsequent inspections.

Asset Type	Inspection Source [8,12]		Total Created Tags (21Q2)[1, 14] (carry-forward from Table 3)						Tags Closed (C) [13] (data as of 06/30/21)						Total Open Tags (O = 21Q2-C)[2] (data as of 06/30/21)					
			A[10]	B	E	F	H[11]	Sub-total	A[10]	B	E	F	H[11]	Sub-total	A[10]	B [15]	E	F	H[11]	Sub-total
Electric Distribution	HFTD	WISP	996	8,630	174,557	10,016	11,030	**205,229**	996	7,586	105,355	6,458	4,383	124,778	-	1,044	69,202	3,558	6,647	80,451
		Non-WISP	11,134	21,795	107,265	26,671	1,024	**167,889**	11,075	13,573	15,741	3,288	158	43,835	59	8,276	92,268	39,339	1,665	141,607
	Non-HFTD / Non-WSIP		35,713	32,126	139,956	49,444	46	**257,285**	35,602	28,501	29,736	4,038	6	97,883	111	3,665	110,936	113,575	59	228,346
	Subtotal		**47,843**	**62,551**	**421,778**	**86,131**	**12,100**	**630,403**	**47,673**	**49,660**	**150,832**	**13,784**	**4,547**	**266,496**	**170**	**12,985**	**272,406**	**156,472**	**8,371**	**450,404**
Electric Transmission	HFTD	WISP	69	4,344	42,992	5,186	-	**52,591**	69	4,336	40,972	3,869	-	**49,246**	-	8	2,020	1,317	-	**3,345**
		Non-WISP	688	3,453	20,125	12,920	-	**37,186**	688	2,696	8,568	3,851	-	**15,803**	-	758	11,819	9,091	-	**21,668**
	Non-HFTD / Non-WSIP		1,393	9,414	41,321	19,925	-	**72,053**	1,392	8,994	16,368	4,513	-	**31,267**	1	420	25,194	15,479	-	**41,094**
	Subtotal		2,150	17,211	104,438	38,031	-	**161,830**	**2,149**	**16,026**	**65,908**	**12,233**	**-**	**96,316**	**1**	**1,186**	**39,033**	**25,887**	**-**	**66,107**
Electric Substation	HFTD	WISP	107	728	2,828	-	-	**3,663**	107	728	2,791	-	-	**3,626**	-	-	37	-	-	**37**
		Non-WISP	509	1,894	6,266	119	-	**8,788**	508	1,620	3,924	15	-	**6,067**	1	274	2,343	117	-	**2,735**
	Non-HFTD / Non-WSIP		1,501	5,281	11,897	166	-	**18,845**	1,500	5,056	10,080	56	-	**16,692**	1	225	1,825	126	-	**2,177**
	Subtotal		2,117	7,903	20,991	285	-	**31,296**	2,115	7,404	16,795	71	-	**26,385**	**2**	**499**	**4,205**	**243**	**-**	**4,949**
Grand Total	HFTD	WISP	1,172	13,702	220,377	15,202	11,030	**261,483**	1,172	12,650	149,118	10,327	4,383	**177,650**	-	1,052	71,259	4,875	6,647	**83,833**
		Non-WISP	12,331	27,142	133,656	39,710	1,024	**213,863**	12,271	17,889	28,233	7,154	158	**65,705**	60	9,308	106,430	48,547	1,665	**166,010**
	Non-HFTD / Non-WSIP		38,607	46,821	193,174	69,535	46	**348,183**	38,494	42,551	56,184	8,607	6	**145,842**	113	4,310	137,955	129,180	59	**271,617**
	Subtotal		**52,110**	**87,665**	**547,207**	**124,447**	**12,100**	**823,529**	**51,937**	**73,090**	**233,535**	**26,088**	**4,547**	**389,197**	**173**	**14,670**	**315,644**	**182,602**	**8,371**	**521,460**

[12] W = WSIP, NW = Non-WSIP, NH/NW = Non-HFTD/Non-WSIP
[13] Closed tags include cancelled, deleted, or tags moved out of scope, in addition to physically completed work; reflects new tags closed since January 1, 2019.
[14] Created Tags reflects the summation of tags open and closed since January 1, 2019, consistent with prior quarterly reports, and not does reflect open tags created prior to 2019.
[15] All B tags initially identified through the WSIP were completed by year 2020; open WSIP B tags reflected below are tags that have had their priority upgraded since the tags were created.

Source: PG&E Q2 2021 Compliance Plan Quarterly Update, dated August 16, 2021

ATTACHMENT 5

PG&E RESPONSE TO TURN 10-9 AND ATTACHMENT 1 AND TURN 10-16A AND -16C FROM THE 2020 GRC



PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase I
Application 18-12-009
Data Response

PG&E Data Request No.:	TURN_010-Q09		
PG&E File Name:	GRC-2020-PhI_DR_TURN_010-Q09		
Request Date:	April 17, 2019	Requester DR No.:	010
Date Sent:	May 15, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:	Jeffrey Deal	Requester:	Marcel Hawiger

SUBJECT: EXHIBIT (PG&E-4) – ELECTRIC DISTRIBUTION, CHAPTERS 2A AND 6

PLEASE INTERPRET THE TERM "FIRE" BROADLY TO INCLUDE "WILDFIRE," "WILDLAND FIRE," "STRUCTURAL FIRE" OR "URBAN FIRE," AS THOSE TERMS ARE USED BY PG&E.

QUESTION 09

Regarding the Non-Exempt Surge Arrester Replacement program (MAT 2AR), PG&E states at p. 6-43:2-12,

> "PG&E has been collaborating with CAL FIRE and equipment manufacturers for several years to develop an exempt surge arrester because such a device could potentially reduce both fire risk and vegetation management costs. [citation omitted] … One vendor, Siemens, received the first ever CAL FIRE provisional certification for an exempt surge arrester in 2014 and received final certification in August of 2017. Another vendor, ABB, received provisional certification of an exempt surge arrester in January 2017."

Please provide the cost-benefit analysis that PG&E performed that compares the cost of replacing existing surge arresters with CAL FIRE-exempt surge arresters against the cost of retaining PG&E's current pole-related vegetation clearance requirements (as set forth in California PRC Sect. 1492). If none exists, please explain why PG&E believes it is not reasonable to compare the cost of vegetation management as a result of the minimum clearance requirements required for the presence of a non-exempt surge arrester against the cost of the replacement of non-exempt surge arresters?

ANSWER 09

It is not reasonable to simply compare the cost of non-exempt surge arrester replacement with on-going subject pole vegetation clearing costs. In the 2017 GRC PG&E presented the need to perform grounding modifications at surge arrester locations to bring the grounding systems up to current PG&E standards. In addition, the new exempt surge arresters provide superior technology that reduces fire risk. PG&E's economic analysis, attached as GRC-2020-PhI_DR_TURN_010-Q09Atch01, compares three alternatives to accomplishing the replacement of non-exempt surge arresters and performing surge arrester grounding modifications. Alternative A in the attached

analysis is PG&E's Non-Exempt Surge Arrester Replacement Program. This alternative is the least cost alternative which accomplishes both surge arrester grounding modifications and the replacement of non-exempt arresters.

Economic Evaluation Over 20-Year Study Period ($000)

Surge Arrester and Ground Repair Analysis

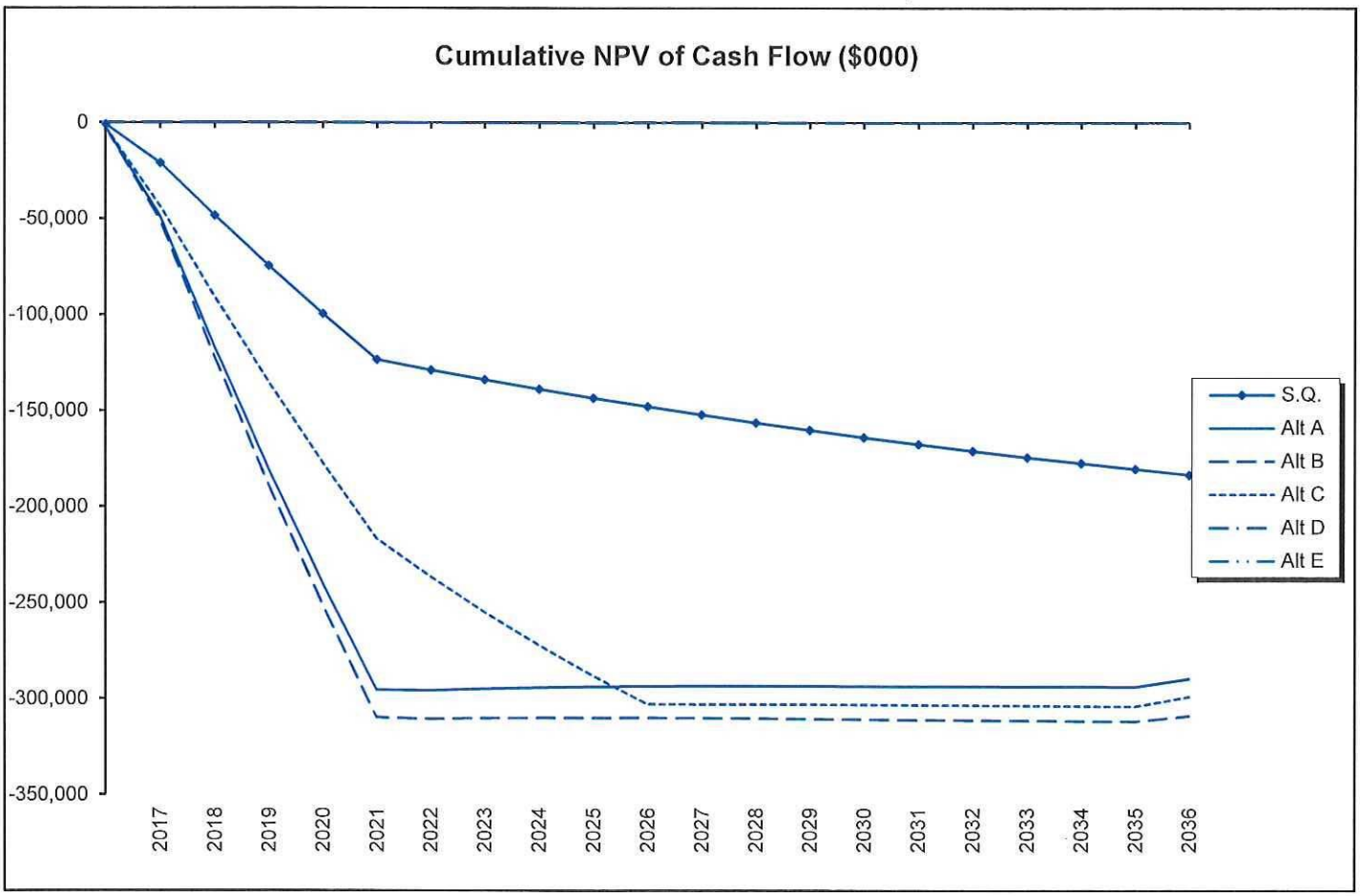
DRAFT - NOT APPROVED

Study Period:	20 years	First Year of Study:	2017	Name of Analyst, Phone #	
Discount Rate:	7.0%	Cost Estimate Year:	2017	EASOP 2018 MaxCap Edition	

Alternatives (enter titles to see financial results)	Cash Flow Measures NPV	ROE	Payback	B/C Ratio	PVRR
Status Quo	-183,155	-	-	-	254,324
A. SA's and Grounds Replaced at same time by 2022	-289,326	n/a	never	0.3	401,750
B. SA's and Grounds Replaced Separately by 2022	-308,742	n/a	never	0.3	428,711
C. 8900 SA Units Per 10-Year, Grounds Replaced by 2022	-298,765	n/a	never	0.3	414,857
D.					
E.					

Net present value and present value of revenue requirements are the primary financial measures.

Return on equity, payback period, and benefit-cost ratio are measured relative to status quo.



Surge Arrester and Ground Repair Analysis
DRAFT - NOT APPROVED

Annual Cash Flow ($000)

End of Year *	S.Q.	Alt A	Alt B	Alt C	Alt D	Alt E
Initial Expenditures	-730	-2,143	-2,249	-2,249	0	0
2017	-21,635	-49,889	-52,025	-44,093	0	0
2018	-31,231	-77,624	-81,151	-53,932	0	0
2019	-32,012	-77,884	-81,636	-54,440	0	0
2020	-32,812	-77,916	-81,958	-54,973	0	0
2021	-33,632	-77,995	-82,311	-55,527	0	0
2022	-7,942	-287	-988	-29,569	0	0
2023	-8,141	1,442	607	-29,497	0	0
2024	-8,345	1,069	332	-29,424	0	0
2025	-8,553	727	79	-29,349	0	0
2026	-8,767	432	-140	-29,256	0	0
2027	-8,986	203	-314	-393	0	0
2028	-9,211	38	-443	95	0	0
2029	-9,441	-67	-529	-98	0	0
2030	-9,677	-115	-575	-261	0	0
2031	-9,919	-154	-614	-398	0	0
2032	-10,167	-193	-655	-510	0	0
2033	-10,421	-235	-697	-600	0	0
2034	-10,682	-277	-741	-667	0	0
2035	-10,949	-320	-785	-715	0	0
2036	-11,222	16,446	11,086	19,301	0	0

* Project expenditures are assumed to occur beginning of year, so shown at end of the previous year.
Annual operating expenses and revenues are assumed to occur at the end of the year.

Earnings Available for Common Stock ($000) *

Calendar Year	S.Q.	Alt A	Alt B	Alt C	Alt D	Alt E
2017	-7,750	-7,020	-7,750	-7,750	0	0
2018	-21,810	-7,176	-21,791	-21,525	0	0
2019	-31,411	-6,142	-30,178	-30,511	0	0
2020	-32,196	-5,053	-29,689	-30,651	0	0
2021	-33,001	-3,905	-29,158	-30,779	0	0

* Earnings are estimated using simplified accounting assumptions and **no cost recovery**.
Earnings estimates for projects over $100 million should be reviewed by Economic and Project Analysis.

Surge Arrester and Ground Repair Analysis
DRAFT - NOT APPROVED
Status Quo

Project Expenditures Over 20 Years (2017-2036) in $000 *

Year	Description	Cost	Esc%	Type	Life	Salvage% Input	Salvage% Calcd	Escalated Cost	NPV
2017	Repair Grounds 617 Locations	1,014	2.5	exp		0		1,014	-730
2018	Repair Grounds 12,043 Locations	19,799	2.5	exp		0		20,294	-13,659
2019	Repair Grounds 19,323 Locations	31,767	2.5	exp		0		33,375	-20,994
2020	Repair Grounds 19,323 Locations	31,767	2.5	exp		0		34,210	-20,111
2021	Repair Grounds 19,323 Locations	31,767	2.5	exp		0		35,065	-19,265
2022	Repair Grounds 19,323 Locations	31,767	2.5	exp		0		35,941	-18,455
			2.5			0		0	0
			2.5			0		0	0
			2.5			0		0	0

Surge Arrester and Ground Repair Analysis
DRAFT - NOT APPROVED
Alternative A - SA's and Grounds Replaced at same time by 2022

Project Expenditures Over 20 Years (2017-2036) in $000 *

Year	Description	Cost	Esc%	Type	Life	Salvage% Input	Salvage% Calcd	Escalated Cost	NPV
2017	Replace 617 Locations	2,143	2.5	ed	40	0		2,143	-2,004
2018	Replace 12,043 Locations	41,825	2.5	ed	40	0		42,871	-37,391
2019	Replace 19,323 Locations	67,109	2.5	ed	40	0		70,506	-57,319
2020	Replace 19,323 Locations	67,109	2.5	ed	40	0		72,269	-54,734
2021	Replace 19,323 Locations	67,109	2.5	ed	40	0		74,076	-52,237
2022	Replace 19,323 Locations	67,109	2.5	ed	40	0		75,928	-49,821
			2.5			0		0	0
			2.5			0		0	0
			2.5			0		0	0

Surge Arrester and Ground Repair Analysis
DRAFT - NOT APPROVED
Alternative B - SA's and Grounds Replaced Separately by 2022

Project Expenditures Over 20 Years (2017-2036) in $000 *

Year	Description	Cost	Esc%	Type	Life	Salvage% Input	Salvage% Calcd	Escalated Cost	NPV
2017	Replace Arresters	1,519	2.5	ed	40	0		1,519	-1,421
2017	Repair Grounds	1,014	2.5	exp		0		1,014	-730
2018	Replace Arresters	29,650	2.5	ed	40	0		30,391	-26,507
2018	Repair Grounds	19,799	2.5	exp		0		20,294	-13,659
2019	Replace Arresters	47,573	2.5	ed	40	0		49,981	-40,633
2019	Repair Grounds	31,767	2.5	exp		0		33,375	-20,994
2020	Replace Arresters	47,573	2.5	ed	40	0		51,231	-38,800
2020	Repair Grounds	31,767	2.5	exp		0		34,210	-20,111
2021	Replace Arresters	47,573	2.5	ed	40	0		52,512	-37,030
2021	Repair Grounds	31,767	2.5	exp		0		35,065	-19,265
2022	Replace Arresters	47,573	2.5	ed	40	0		53,824	-35,318
2022	Repair Grounds	31,767	2.5	exp		0		35,941	-18,455
			2.5			0		0	0
			2.5			0		0	0
			2.5			0		0	0

Surge Arrester and Ground Repair Analysis
DRAFT - NOT APPROVED
Alternative C - 8900 SA Units Per 10-Year, Grounds Replaced by 202

Project Expenditures Over 20 Years (2017-2036) in $000 *

Year	Description	Cost	Esc%	Type	Life	Salvage% Input	Salvage% Calcd	Escalated Cost	NPV
2017	Replace Arresters	1,519	2.5	ed	40	0		1,519	-1,421
2017	Repair Grounds	1,014	2.5	exp		0		1,014	-730
2018	Replace Arresters	21,912	2.5	ed	40	0		22,460	-19,589
2018	Repair Grounds	19,799	2.5	exp		0		20,294	-13,659
2019	Replace Arresters	21,912	2.5	ed	40	0		23,021	-18,715
2019	Repair Grounds	31,767	2.5	exp		0		33,375	-20,994
2020	Replace Arresters	21,912	2.5	ed	40	0		23,597	-17,871
2020	Repair Grounds	31,767	2.5	exp		0		34,210	-20,111
2021	Replace Arresters	21,912	2.5	ed	40	0		24,187	-17,056
2021	Repair Grounds	31,767	2.5	exp		0		35,065	-19,265
2022	Replace Arresters	21,912	2.5	ed	40	0		24,791	-16,267
2022	Repair Grounds	31,767	2.5	exp		0		35,941	-18,455
2023	Replace Arresters	21,912	2.5	ed	40	0		25,411	-15,504
2024	Replace Arresters	21,912	2.5	ed	40	0		26,046	-14,765
2025	Replace Arresters	21,912	2.5	ed	40	0		26,698	-14,047
2026	Replace Arresters	21,912	2.5	ed	40	0		27,365	-13,351
2027	Replace Arresters	21,912	2.5	ed	40	0		28,049	-12,675
			2.5			0		0	0
			2.5			0		0	0
			2.5			0		0	0

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase I
Application 18-12-009
Data Response

PG&E Data Request No.:	TURN_010-Q16		
PG&E File Name:	GRC-2020-PhI_DR_TURN_010-Q16		
Request Date:	April 17, 2019	Requester DR No.:	010
Date Sent:	May 8, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:	Jeffrey Deal	Requester:	Marcel Hawiger

SUBJECT: EXHIBIT (PG&E-4) – ELECTRIC DISTRIBUTION, CHAPTERS 2A AND 6

PLEASE INTERPRET THE TERM "FIRE" BROADLY TO INCLUDE "WILDFIRE," "WILDLAND FIRE," "STRUCTURAL FIRE" OR "URBAN FIRE," AS THOSE TERMS ARE USED BY PG&E.

QUESTION 16

At p. 6-43:13-19, PG&E states,

> "PG&E has an estimated 90,788 non-exempt surge arresters in its service territory. PG&E plans, through the new Non-Exempt Surge Arrester Replacement Program described here, to replace these non-exempt surge arresters with new exempt surge arresters at the same time it performs the corrective grounding work previously forecast as part of the Surge Arrester Grounding Program discussed in the 2017 GRC."

a. Within the 90,788-pole population of locations with non-exempt surge arresters, how many have non-exempt equipment and/or scheme types (e.g., non-exempt line junction) by each of the following types of equipment and scheme types? (Please provide a separate count for each of the following items and disaggregate each count between locations that are within (1) Tier 2 HFTD areas, (2) Tier 3 HFTD areas, and (3) outside of Tier 2 and Tier 3 HFTD areas.)
   i. Fuses
   ii. Disconnects
   iii. Transformers
   iv. Hot tap clamps
   v. Split-bolt and/or other types of connectors
   vi. Grasshopper air switches
   vii. Other equipment that is subject to the clearance requirements of California PRC 4292 but not exempt by CAL FIRE
   viii. Line junction or dead end or corner pole, etc.

b. How many of the poles that PG&E identifies in each subpart of part (a) of this question will PG&E endeavor to replace non-exempt equipment or scheme (e.g., non-exempt line junction), such that CAL FIRE would exempt the specified piece of equipment or line scenario from the clearance requirements set forth in California PRC 4292 (as permitted by CCR Title 14, Section 1255) and any relevant local pole-related clearance requirements, as of the end of the GRC period (i.e., 2020)? Please provide a count for each subpart of part a, disaggregated by locations that are within (1) Tier 2 HFTD areas, (2) Tier 3 HFTD areas, and (3) outside of Tier 2 and Tier 3 HFTD areas.

c. How many of the 90,788 locations that have non-exempt surge arresters does CAL FIRE consider to be subject to the clearance distance required by California PRC 4292 (i.e., poles associated with

> "electrical … distribution line upon any mountainous land, or forest-covered land, brush-covered land, or grass-covered land … during such times and in such areas as are determined to be necessary by the director or the agency which has primary responsibility for fire protection of such areas… " (emphasis added)).

To the extent that PG&E has fewer than 90,788 surge arresters that CAL FIRE has determined to be subject to California PRC 4292 clearance requirements, please explain why PG&E's replacement program includes the replacement of surge arresters on poles that fall outside of the scope of California PRC 4292, as determined by CAL FIRE?

Please note: TURN is interested in the clearance requirements under California PRC 4292 related to equipment locations with respect to mountainous and/or vegetated terrain, not in whether locations do or do not have exempted equipment (under CCR Title 14, Section 1255).

d. How many of the 90,788 non-exempt surge-arrester locations are in (i) Tier 2 HFTD areas (please disaggregate the counts in Tier 2 by Low, Medium, and High fire risk areas, as identified on p. 6-48:14-16), (ii) Tier 3 HFTD areas (please disaggregate the counts in Tier 3 HFTD areas by Low, Medium, and High fire risk areas, as identified on p. 6-48:14-16, if such designations exist for poles in Tier 3 HFTD areas), and (iii) Tier 1 areas that are outside of both Tier 2 and Tier 3 areas?

e. If applicable:

   i. Why does PG&E's proposal to replace non-exempt surge arresters include locations that are outside of Tier 2 or Tier 3 HFTD areas?

   ii. Why does PG&E's proposal to replace non-exempt surge arresters include locations that are outside of Tier 1, Tier 2 and Tier 3 HFTD areas?

f. Did PG&E install any non-exempt surge arresters between the years, 2015-2019 (inclusive)? If so:

   i. Why did PG&E install non-exempt surge arresters during this period, given that CAL FIRE gave a provisional certification for an exempt surge arrester to Siemens in 2014?

ii. How many non-exempt surge arresters did PG&E install in each year, if any and regardless of the program (e.g., routine maintenance, emergency maintenance, etc.), and what was the total cost of doing so in each year, 2015-2018 (inclusive)?

iii. Please disaggregate the data requested in part f.ii between such surge arresters that PG&E installed in either Tier 2 or 3 HFTD areas and those that fall outside of those areas.

iv. Please disaggregate the data requested in part f.ii between such surge arresters that were installed on target poles (i.e., those for which CAL FIRE has determined that California PRC 4292 clearance requirements apply because of mountainous terrain and vegetation considerations, not because of whether poles have nonexempt equipment, or not), and those locations in which CAL FIRE has determined that California PRC 4292 clearance requirements do not apply.

g. How many exempt surge arresters did PG&E install, if any, regardless of the program (e.g., routine maintenance, emergency maintenance, etc.), and what was the total cost of doing so in each year, 2014-2018 (inclusive)? Please disaggregate the requested data between such surge arresters that PG&E installed in either Tier 2 or 3 HFTD areas and those that fall outside of those areas.

ANSWER 16

a. PG&E cannot provide the exact information requested because it requires correlating data sets collected to support the needs of two different programs, which are not easily cross-referenced. However, PG&E will provide information to the extent it is available.

The estimate of 90,788 non-exempt surge arresters in PG&E's service territory referenced in the question is based on a location survey, originally conducted for PG&E's surge arrester grounding program, which only captured locations where grounding work might be required because transformers and surge arresters existed on the same pole. The location survey's scope of work did not include capturing other non-exempt equipment asset information.

PG&E does have some data concerning how many poles in HFTD areas have both surge arresters and other equipment. PG&E's Vegetation Management program maintains a database of all poles which are subject to California Public resources Code (PRC) 4292 because of the presence of non-exempt equipment on the poles, including a description of which types of non-exempt equipment are on the pole. This database also contains a field for GIS coordinates and, to the extent possible, PG&E has recently mapped the poles in this database to the HFTDs based on each pole's GIS coordinates. However, this mapping may not be completely accurate because GIS information is not necessary to the operation of the Vegetation Management pole clearing program, so some records show GIS information for the location where information about the pole was entered into the database (information was sometimes collected on paper and entered after the fact into the database). In addition, a small number of poles have no associated GIS information. Also, some of the poles identified in this database may not be part of

the 90,788 locations identified since there may not be a transformer at all poles identified in the subject pole database.

The table below shows the number of poles in the Vegetation Management subject pole database with both a surge arrester and another piece of non-exempt equipment with GIS locations in the database that correspond to HFTD Zone 1, Tier 2, or Tier 3.

With Surge Arresters	Zone 1	Tier 2	Tier 3
Universal Fuse	16	1,585	420
Open Link Fuse	11	4,942	1,081
Hot Tap Clamp	1	72	12
Split Bolt Connector	2	311	76
Other Miscellaneous Equipment	-	83	30
Solid Blade Disconnect	7	278	122
In Line Disconnect	1	106	24
Transmission Switch	-	1	-
Total	38	7,378	1,765

b. The primary goals of the non-exempt surge arrester replacement program are: (1) to bring the grounding for surge arresters located on the same pole as a distribution transformer up to PG&E's current engineering standard; and (2) to use the opportunity provided by the need to do the grounding work to also replace non-exempt surge arresters in those locations in order to reduce fire risk. PG&E did not identify other non-exempt equipment as part of the original inventory of surge arrester locations and the program is not designed with the goal of removing all non-exempt equipment located on the same pole as the surge arresters that will be replaced. However, when replacing non-exempt surge arresters, PG&E is also replacing some minor non-exempt equipment (i.e., hot tap clamps and/or split bolt connectors) when it is found and is the only other non-exempt equipment on the pole, which will eliminate the clearance requirements of PRC 4292 for those poles. Outside of this minor equipment and surge arresters, no other non-exempt equipment is being replaced as part of the surge arrester program.

c. PG&E objects that this request is vague and ambiguous. PG&E further objects to this request to the extent that it seeks what Cal FIRE "considers" or "determine[d]" with regard to the applicability of certain statutory requirements. PG&E cannot respond on behalf of Cal FIRE. Subject to and notwithstanding these objections, PG&E responds as follows:

TURN notes in its question that it is interested in the clearance requirements "under California PRC 4292 related to equipment locations with respect to mountainous and/or vegetated terrain, not in whether locations do or do not have exempted equipment." But California PRC 4292 only applies to poles in mountainous and/or vegetated terrain (i.e. State Responsibility Areas) to the extent that those poles have non-exempt equipment on them.

For the reasons discussed in PG&E's response to part a, above, PG&E does not have precise information about which of the locations identified in its surge arrester inventory are subject to California PRC 4292 requirements. The primary goals for the surge arrestor program are described in subpart b. The locations that require grounding modification are found throughout PG&E's system, not just in the State Responsibility Areas subject to PRC 4292. PG&E is replacing non-exempt surge arresters at all locations where grounding work is also being performed, to take advantage of the efficiency of bundling the two types of work, and to reduce fire risk.

d. PG&E cannot provide the exact information requested by this question for the reasons explained in subpart a. PG&E will provide information to the extent it is available. Based on a mapping of the GIS coordinates of locations identified in PG&E's surge arrester inventory to the boundaries of the HFTD areas, PG&E provides the following estimate, by HFTD area, of remaining locations forecast to be worked in 2019-2022: Tier 2 - 26,020 locations, Tier 3 – 11,846 locations. There are another estimated 42,781 locations outside of HFTD Tier 2 and Tier 3 areas that require work; PG&E expects a small number of these will be in Zone 1 of the HFTD – which represents less than 0.5 percent of the total HFTD[1] – but has not separately calculated that number.

The Low, Medium and High fire risk assessment identified on p. 6-48:14-16 is an assessment of vegetation-related fire risk at the base of individual subject poles that has historically been performed by Vegetation Management pre-inspectors and entered into Vegetation Management's subject pole database. The designations, which are based on an evaluation of terrain, slope and vegetation characteristics, pre-date the creation of HFTD boundaries. Based on the recent mapping of subject pole locations to the HFTD boundaries described in the response to part a, above (and subject to the same caveats), the table below shows the Low/Medium/High designation of poles with non-exempt surge arresters in HFTD Zone 1, Tier 2, and Tier 3:

Zone 1			Tier 2			Tier 3		
High	Medium	Low	High	Medium	Low	High	Medium	Low
34	102	88	8,955	12,139	9,431	5,369	4,849	3,382

e.

i. Please see PG&E's response to part b, above explaining PG&E's rationale for replacing non-exempt surge arresters in all locations where grounding modification work is required.

ii. PG&E assumes TURN is inquiring about Zone 1 of the HFTD when referring to Tier 1 of the HFTD. Please see PG&E's response to part b, above explaining PG&E's rationale for replacing non-exempt surge arresters in all locations where grounding modification work is required.

f. Yes, PG&E did install some non-exempt surge arresters between 2015 and 2019.

---

[1] See Ex. (PG&E-4), Chapter 2A and 2A-16, lines 9-13.

i. Although CAL FIRE gave provisional certification for an exempt Siemens arrester in 2014, PG&E's pilot evaluation of the exempt Siemens arrester identified material and design issues which made the Siemens arrester incompatible with PG&E's distribution system except in certain limited circumstances. Another vendor designed an exempt arrester around PG&E's requirements and received CAL FIRE certification in 2017. PG&E began installing this second vendor's exempt arresters in 2017 and continues to use them for the program.

ii. PG&E objects to this question on the grounds that the question asks for actual 2018 data while PG&E's 2020 GRC forecast uses a base year of 2017 recorded data in accordance with the Commission's Rate Case Plan. Notwithstanding the foregoing, and without waiving PG&E's right to object to the admissibility of the requested information into evidence, PG&E responds as follows:

The table below shows the number of non-exempt surge arresters installed as replacements between 2015 and 2018 as part of the PG&E's routine maintenance program. PG&E began installing exempt surge arresters during 2017. The values shown below for 2017 and 2018 represent the total number of surge arresters replaced during routine maintenance. Without performing a field inspection, PG&E cannot validate with 100% certainty whether the arresters installed in 2017 and 2018 outside of the Non-Exempt Surge Arrester replacement program utilized exempt or non-exempt arresters:

Year	Cost to Replace Surge Arrester	Replacement Volume
2015	$1,111,289	369
2016	$760,737	334
2017	$854,614	361
2018	$870,264	284
Total	**$3,596,904**	**1,348**

iii. The CPUC designated HFTDs as part of Decision Adopting Regulations to Enhance Fire Safety in High Fire Threat Districts (D.17-12-024) near the end of 2017. Therefore, PG&E did not start tracking installations in terms of whether they were located in Tier 2 or Tier 3 HFTD areas until 2018. The table below shows the 2018 data from the table above, by HFTD area:

2018	Cost to Replace Surge Arrester	Replacement Volume
	$625,541	207
Tier 2	$134,238	46
Tier 3	$110,485	31
Total	**$870,264**	**284**

iv. PG&E did not track whether the replacements were made on poles subject to California PRC 4292 vegetation clearance requirements.

g. PG&E did not begin installing exempt surge arresters until 2017. The number of exempt arrester locations installed exclusively through the dedicated surge arrester replacement program (MAT 2AR) in years 2017 and 2018 was 619 and 12,615 respectively. As noted in the response to part f.iii, PG&E captured the HFTD information for the pole locations of replacements beginning for 2018. The recorded costs for the MAT 2AR program during this time frame were $4.474 million in 2017 and $45.419 million in 2018. The replacement volume for 2018, sorted by HFTD tier, is shown in the table below (PG&E does not have a breakdown of cost by HFTD tier for the MAT 2AR Program for 2017):

2018	Replacement Volume
	8,148
Tier 2	4,143
Tier 3	324
Total	**12,615**

In addition, PG&E has identified 8 exempt surge arresters that were installed as part of the routine maintenance program in 2018. The location and cost of these replacements are shown in the table below:

2018	Cost to Replace Surge Arrester	Replacement Volume	Replacement Unit Cost
	$18,131	5	$3,626
Tier 2	$1,762	1	$1,762
Tier 3	$6,695	2	$3,347
Total	**$26,588**	**8**	**$3,323**

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase I
Application 18-12-009
Data Response

PG&E Data Request No.:	TURN_010-Q16		
PG&E File Name:	GRC-2020-PhI_DR_TURN_010-Q16Rev01		
Request Date:	April 17, 2019	Requester DR No.:	010
Date Sent:	May 8, 2019 (Original) May 9, 2019 (Revised)	Requesting Party:	The Utility Reform Network
PG&E Witness:	Jeffrey Deal	Requester:	Marcel Hawiger

SUBJECT: EXHIBIT (PG&E-4) – ELECTRIC DISTRIBUTION, CHAPTERS 2A AND 6

PLEASE INTERPRET THE TERM "FIRE" BROADLY TO INCLUDE "WILDFIRE," "WILDLAND FIRE," "STRUCTURAL FIRE" OR "URBAN FIRE," AS THOSE TERMS ARE USED BY PG&E.

QUESTION 16

At p. 6-43:13-19, PG&E states,

> "PG&E has an estimated 90,788 non-exempt surge arresters in its service territory. PG&E plans, through the new Non-Exempt Surge Arrester Replacement Program described here, to replace these non-exempt surge arresters with new exempt surge arresters at the same time it performs the corrective grounding work previously forecast as part of the Surge Arrester Grounding Program discussed in the 2017 GRC."

a. Within the 90,788-pole population of locations with <u>non-exempt</u> surge arresters, how many have non-exempt equipment and/or scheme types (e.g., non-exempt line junction) by each of the following types of equipment and scheme types? (Please provide a separate count for each of the following items and disaggregate each count between locations that are within (1) Tier 2 HFTD areas, (2) Tier 3 HFTD areas, and (3) outside of Tier 2 and Tier 3 HFTD areas.)
   i. Fuses
   ii. Disconnects
   iii. Transformers
   iv. Hot tap clamps
   v. Split-bolt and/or other types of connectors
   vi. Grasshopper air switches
   vii. Other equipment that is subject to the clearance requirements of California PRC 4292 but not exempt by CAL FIRE
   viii. Line junction or dead end or corner pole, etc.

b. How many of the poles that PG&E identifies in each subpart of part (a) of this question will PG&E endeavor to replace non-exempt equipment or scheme (e.g., non-exempt line junction), such that CAL FIRE would exempt the specified piece of equipment or line scenario from the clearance requirements set forth in California PRC 4292 (as permitted by CCR Title 14, Section 1255) and any relevant local pole-related clearance requirements, as of the end of the GRC period (i.e., 2020)? Please provide a count for each subpart of part a, disaggregated by locations that are within (1) Tier 2 HFTD areas, (2) Tier 3 HFTD areas, and (3) outside of Tier 2 and Tier 3 HFTD areas.

c. How many of the 90,788 locations that have non-exempt surge arresters does CAL FIRE consider to be subject to the clearance distance required by California PRC 4292 (i.e., poles associated with

> "electrical … distribution line upon any mountainous land, or forest-covered land, brush-covered land, or grass-covered land … during such times and in such areas as are determined to be necessary by the director or the agency which has primary responsibility for fire protection of such areas… " (emphasis added)).

To the extent that PG&E has fewer than 90,788 surge arresters that CAL FIRE has determined to be subject to California PRC 4292 clearance requirements, please explain why PG&E's replacement program includes the replacement of surge arresters on poles that fall outside of the scope of California PRC 4292, as determined by CAL FIRE?

Please note: TURN is interested in the clearance requirements under California PRC 4292 related to equipment locations with respect to mountainous and/or vegetated terrain, not in whether locations do or do not have exempted equipment (under CCR Title 14, Section 1255).

d. How many of the 90,788 non-exempt surge-arrester locations are in (i) Tier 2 HFTD areas (please disaggregate the counts in Tier 2 by Low, Medium, and High fire risk areas, as identified on p. 6-48:14-16), (ii) Tier 3 HFTD areas (please disaggregate the counts in Tier 3 HFTD areas by Low, Medium, and High fire risk areas, as identified on p. 6-48:14-16, if such designations exist for poles in Tier 3 HFTD areas), and (iii) Tier 1 areas that are outside of both Tier 2 and Tier 3 areas?

e. If applicable:

   i. Why does PG&E's proposal to replace non-exempt surge arresters include locations that are outside of Tier 2 or Tier 3 HFTD areas?

   ii. Why does PG&E's proposal to replace non-exempt surge arresters include locations that are outside of Tier 1, Tier 2 and Tier 3 HFTD areas?

f. Did PG&E install any non-exempt surge arresters between the years, 2015-2019 (inclusive)? If so:

   i. Why did PG&E install non-exempt surge arresters during this period, given that CAL FIRE gave a provisional certification for an exempt surge arrester to Siemens in 2014?

ii. How many non-exempt surge arresters did PG&E install in each year, if any and regardless of the program (e.g., routine maintenance, emergency maintenance, etc.), and what was the total cost of doing so in each year, 2015-2018 (inclusive)?

iii. Please disaggregate the data requested in part f.ii between such surge arresters that PG&E installed in either Tier 2 or 3 HFTD areas and those that fall outside of those areas.

iv. Please disaggregate the data requested in part f.ii between such surge arresters that were installed on target poles (i.e., those for which CAL FIRE has determined that California PRC 4292 clearance requirements apply because of mountainous terrain and vegetation considerations, not because of whether poles have nonexempt equipment, or not), and those locations in which CAL FIRE has determined that California PRC 4292 clearance requirements do not apply.

g. How many exempt surge arresters did PG&E install, if any, regardless of the program (e.g., routine maintenance, emergency maintenance, etc.), and what was the total cost of doing so in each year, 2014-2018 (inclusive)? Please disaggregate the requested data between such surge arresters that PG&E installed in either Tier 2 or 3 HFTD areas and those that fall outside of those areas.

ANSWER 16 REVISED 01

g. PG&E did not begin installing exempt surge arresters until 2017. The number of exempt arrester locations installed exclusively through the dedicated surge arrester replacement program (MAT 2AR) in years 2017 and 2018 was 619 and 12,615 respectively. As noted in the response to part f.iii, PG&E captured the HFTD information for the pole locations of replacements beginning for 2018. The recorded costs for the MAT 2AR program during this time frame were $4.474 million in 2017 and $45.419 million in 2018. The replacement volume for 2018, sorted by HFTD tier, is shown in the table below (PG&E does not have a breakdown of cost by HFTD tier for the MAT 2AR Program for 2017):

2018	Replacement Volume
	8,148
Tier 2	4,143
Tier 3	324
Total	**12,615**

As noted in the response to part f.ii, PG&E can not determine with certainty the replacements outside of the Surge Arrester Replacement Program.

ATTACHMENT 6

EXCERPT OF THE DIRECT TESTIMONY (EX. TURN-3) AND ATTACHMENTS (EX. TURN-3-ATCH1) OF GARRICK F. JONES FROM PG&E'S 2017 GRC (REGARDING THE SURGE ARRESTER GROUNDING (SAG) PROGRAM)



Exhibit Number TURN-3

Testimony of Garrick F Jones in Pacific Gas and Electric Company's 2017 Test Year General Rate Cases

Prepared testimony of
Garrick F Jones

JBS Energy, Inc.
311 D Street
West Sacramento
California, USA 95605
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On behalf of
The Utility Reform Network (TURN)

California Public Utilities Commission
Docket # A.15-09-001

April 29, 2016

Revised May 24, 2016

1. Overhead Preventive Maintenance (MAT KA)

a. Surge Arrestor Grounding (MWC KAR)

i. Introduction

The SAG Project, is a new, proactive O&M program where PG&E's stated goal is to replace all common grounds between transformer secondary neutrals and the transformers' associated surge arrestors (also called lighting arrestors) where the transformer's secondary neutral is single-grounded.[20] PG&E claims, "This will reduce the risk of equipment and property damage and will ensure PG&E's compliance with current regulatory guidance."[21]

The Test Year forecast is $20.502 million, which equates to $81.503 million for the GRC period; PG&E estimates that the entire length of the program would cost $105.3 million over six years.[22]

It is questionable that ratepayers should pay for any of this program, which will be fleshed out the testimony that follows.

Briefly, there are two types of surge arrestor configurations: 1) tank-mounted and 2) non-tank-mounted. PG&E received an interpretation from CPUC staff in 1974 wherein staff agreed that G.O. 95 allows for non-tank-mounted arrestors to be ground in common[23] with the transformer's neutral ground. The CPUC staff's interpretation did not cover tank-mounted arrestors, but PG&E changed the engineering documents related to tank-mounted arrestors anyway and is now asking for funding for corrections for both tank- and non-tank-mounted arrestor configurations.

Furthermore, G.O. 95 allows for common grounds between arrestors in either of the configurations described above when the transformer's neutral is grounded as part of a common-ground system, as opposed to configurations using a single-ground that is not connected to the grounds of other transformers. The survey PG&E performed to

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[20] Ex. PG&E-4, p. WP 6-33.

[21] Ex. PG&E-4, p. 6-35 (lines 28-30).

[22] Ex. PG&E-4, p. WP 6-3.

[23] i.e., have spark-gap between grounds removed.

ascertain how many ground configurations it would need to correct did not differentiate between those configurations where the neutral is in a common-ground system from those that are in a single-ground configuration. Therefore, PG&E's forecast, which is based on this survey, includes configurations which do not need to be replaced and is, by definition, too high.

Any ratepayer funding that the Commission authorizes for this program should be part of a balancing account to protect ratepayers from PG&E's forecasting error. If the Commission does not remove all ratepayer funding for this program, TURN's primary recommendation is that the Commission adopt a limited program that lengthens the period of the program from six to twelve years; uses a balancing account to ensure that ratepayer will not have to pay for the over-forecasted configurations that do not need replacement; removes the over collection for the incorrectly forecasted configurations where the transformer is part of a common-ground system and do not need to be replaced; and removes the configurations that involve tank-mounted surge arrestors because PG&E never received a staff interpretation confirming G.O. 95 permits common grounding of such surge-arrestor configurations and should not have changed these in the first place. PG&E should charge all tank-mounted surge arrestor corrections below the line. Also, the Commission should order that 20% of each correction involving non-tank-mounted surge-arrestor configurations should be charged below the line, given that this is a program to solve a problem created by PG&E's own proposal.

ii. Analysis

- Terminology and Technical Overview

PG&E states:

> The Surge Arrestor Grounding program is a new maintenance program for which PG&E seeks funding in this GRC. Surge arrestors, also known as lightning arrestors, lessen the risk of PG&E equipment failure and consequent customer property damage due to overvoltage events such as lightning strikes. Surge arrestors are connected to earth via a ground wire and ground rods.
>
> …
>
> Prior to 1974, PG&E's practice was to interconnect the grounds of the transformer secondary neutral and surge arrestors through a spark gap, effectively creating two separate grounds. …Between 1974 and 2008,

> when surge arrestors were installed in the same location as distribution transformers, PG&E often used a shared ground wire and ground rods to ground both the surge arrestors and the transformers.
>
> …
>
> In 2008, PG&E revised its work standards to require separate grounding in new installations of surge arrestors and distribution transformers."[24]

It will help the reader to follow the testimony below a little better, however, with some more terminology and explanation.

First, there are two types of relevant transformer secondary neutrals that are associated with surge arrestors on PG&E's system.

One is a secondary neutral that is part of a common-neutral system. Rule 33.3 in General Order (G.O.) 95 allows such secondary neutrals to be grounded in common with an associated surge arrestor because it has the benefit of being connected to the grounds of the other secondary neutrals in the common-neutral *system*.

The other is a single-grounded secondary neutral, which, by definition, has one ground and has not benefit of being part of a *system*. This is the type of secondary neutral that Rule 33.3 in G.O. 95 does not allow to be grounded in common (i.e., not separately grounded) with the ground of the associated surge arrestor.

Second, surge arrestors, themselves, are either tank-mounted—i.e., mounted on the side of a transformer—or non-tank-mounted. The latter are usually attached on the crossarms of the distribution pole. This is important because the CPUC staff expressed an interpretation that common grounds were allowed on one type of surge arrestor mounting but not the other, even though PG&E changed the engineering drawings for both, as we will see below.

- History

It is important to have a firm understanding of the history of surge-arrestor grounding configuration at PG&E in order to effectively evaluate this program.

[24] Ex. PG&E-4, p. 6-35 (lines 15-28).

Before 1974, PG&E's engineering drawings required that the company install the grounds for all surge arrestors separately from the secondary neutrals of any pole-mounted secondary transformers that they were associated with.[25]

In 1974, PG&E developed a proposal to modify Drawing No. 015229 as it pertained to lighting arrestors, including how they are grounded; the company shared the proposal with CPUC staff on January 23 of that year, and PG&E sought "clarify[ication] of the intent of General Order No. 95, Rule 33.3(b)."[26] PG&E has no idea why it made the proposal to change its engineering drawings.[27]

The following is the exact wording from PG&E's February 1, 1974 memorandum regarding the meeting with CPUC staff:

> The summary listed below is an interpretation for General Order No. 95 when applied to lighting arresters.
>
> It was agreed that the isolating gap presently used on transformer installations protected by lighting arresters, that are not tank-mounted, should be eliminated, and the arrester ground connected solidly to the transformer neutral ground. The neutral ground is considered part of the circuit protected by the lighting arrester and, therefore, the interconnection is permitted under Rule 33.3(b) of General Order No. 95.
>
> The isolating gap will continue to be installed on the transformer tank when arresters are tank-mounted, in accordance with P.G. and E. Drawing No. 015229, Sheet 9.[28]

The following happened after the January meeting.

- On May 21, 1974, PG&E revised sheets 8 and 9 of Drawing No. 015229 to eliminate the spark gap,[29] despite CPUC staff's 1974 "interpretation"[30] that Rule

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[25] Id., p. WP 6-33.

[26] PG&E, Memorandum to the File (February 1, 1974) regarding a January 23, 1974 meeting between PG&E and CPUC staff. Provided in Atch02 of the response to TURN DR 9-3.

[27] TURN DR 69-25.d.

[28] PG&E, Memorandum to the File (February 1, 1974) regarding a January 23, 1974 meeting between PG&E and CPUC staff.

[29] TURN DR 69-22.a.i.

[30] PG&E refers to the interpretation of G.O. 95 interchangeably as "interpretation" (see PG&E's response to TURN DR 69-19) and "guidance" (see Ex. PG&E-4, p. 6-35).

33.3(b) from G.O. 95 explicitly allows only the change as it involves the configuration in Sheet 8.[31] PG&E, therefore, begins to install all surge-arrestor groundings in common with the groundings of the secondary neutrals of pole-mounted transformers.

- Fast forward to 2007, when PG&E again asked CPUC staff for clarification regarding the permissibility (by G.O. 95) of common-grounding of surge arrestors and secondary neutrals when the neutral is single-grounded (as opposed to in a common-ground system). This time, as correspondence with the staff indicates, a CPUC staff member said that the common-grounding practice is never allowed under G.O. 95 unless the secondary neutral is in a common neutral system.[32] Of note, the Commission did not order PG&E to make any corrections of common-ground configurations.[33]

- Also in 2007, PG&E discovered that neither San Diego Gas & Electric (SDG&E) nor Southern California Edison (SCE) uses common-ground practices when the neutral is single grounded.[34]

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[31] PG&E now claims that "[g]iven that both sheets 8 and 9 of engineering document 015229 were revised on May 21, 1974 and that PG&E had discussed the elimination of isolating gaps with the CPUC earlier that year, [the company] assumes the changes were made as a result of the interpretation received from the CPUC staff at that time" (TURN DR 69-22.a.ii) Besides this guess, PG&E has no basis for changing Sheet 8—the sheet that pertains to tank-mounted surge arrestors, however, as shown in PG&E's 1974 memo, included above. While an interpretation of CPUC Staff memo regarding the same meeting (CPUC, Memorandum of Hearing or Conference (February 4, 1974) regarding Proposed Elimination of Spark Gap device from Lighting Arrestors on Transformers – G.O. 95; provided in Atch01 of the response to TURN DR 9-3) could be that G.O. 95 permits the removal of spark gaps from all arresters associate with pole-mounted transformers—even where tank-mounted arrestors are implicated—it is clear from PG&E's memorandum of the same event that the Commission's interpretation of G.O. 95—or at least PG&E's interpretation of the Commission's interpretation—was applicable only to arrestors that are not tank-mounted.

[32] Letter from Mr. Julien Ajello, CPUC Gas and Electric Safety to Mr. Pat Geoffry, PG&E, dated October, 12, 2007. Provided in Atch02 of the response to TURN DR 9-2.

[33] TURN DR 9-4.c.

[34] Internal PG&E emails regarding SDG&E's (October 16, 2007, furnished in TURN DR 69-22 Atch. 09) and SCE's (May 31, 2007, Id., Atch. 03) practices. Furthermore, a PG&E employee relayed the following a conversation with SDG&E: "[SDG&E doesn't] usually have [surge arrestors] and transformers on the same pole (other than transformers with provisions for tank

- In 2008, PG&E changed its engineering drawings for new, single-grounded transformer-surge-arrestor combinations[35] presumably on the basis of the 2007 clarification. This change reversed the decision to remove the spark gap (made in 1974) by reinserting the spark gap into the engineering drawings.

- Also in 2008, PG&E began the process of replacing common grounds with separate grounds during the course of regular maintenance.[36]

- In 2010, PG&E re-evaluated its plan to replace grounds during the course of regular maintenance.[37]

- PG&E waited until 2014 to begin proactive replacements[38]—through the SAG Project, which it estimates will cost $105.3 million over six years, as noted above.

- PG&E states at the end of 2015: "[c]ommon grounding of surge arrestors and transformers is not a significant cause of PG&E equipment failure, so…has not performed…analysis…of damage to customer property due to "common grounding" of surge arrestors and transformers."[39]

- Frequency and consequences of surge-arrestor failure

PG&E was aware of no incidents of property damage where the company considered common grounds as the root cause of a given failure or a contribution to a given instance of property damage as of 2008.[40] It appears that, as a result, PG&E was not terribly concerned about the common-ground issue even after becoming aware of the inconsistency. Indeed, the company's first plan (in 2008) was to correct the

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mounted arrestors) so [the SDG&E employee] wasn't sure how often it comes up. I got the impression that they use a lot of L.A.'s in San Diego" (TURN DR 69-22 Atch. 09).

[35] Ex. PG&E-4, p. WP 6-33.

[36] Id.

[37] *Surge Arrester Grounding, Briefing for SED* (04/22/14), p. 2. PUC Legal Division provided the document to TURN on March 11, 2016 in response to Public Records Act Request (PRAR), Ref. No. PRA #1913.

[38] Ex. PG&E-4, pp. WP 6-33 – 6-34.

[39] TURN DR 9-2.a and TURN DR 9-2.b.

[40] TURN DR 69-4.b.

inconsistency as employees found them on the system through regular maintenance,[41] although PG&E completed only "very few units."[42] PG&E estimated that there were 89,000 such locations in 2010 and now has 95,000 actual, surveyed locations.[43] The fact that PG&E has only completed "very few units" through the course of regular maintenance would seem to indicate a low priority for this activity. In fact, as of November 4, 2016, PG&E believes "[c]ommon grounding of surge arrestors and transformers is not a significant cause of PG&E equipment failure, so…has not performed…analysis…of damage to customer property due to "common grounding" of surge arrestors and transformers."[44]

Despite the fact that PG&E has given this activity very low priority and does not believe the issue is a significant cause of equipment failure, PG&E has now decided upon a large-scale, $105 million SAG Project without any analysis regarding risk of failure or resulting property damage.[45]

PG&E was served a lawsuit by a customer whose residence suffered a fire in 2010 that he or she alleged was the result of a failed surge arrestor in combination with the combined ground.[46] Although the suit settled in 2014 through mediation, PG&E's initial investigation concluded that the house fire was likely caused by something other than a failed surge arrestor,[47] and PG&E did not determine the root cause of the surge arrestor

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[41] Ex. PG&E-4, p. 6-33.

[42] TURN 9-5.c.

[43] TURN 9-5.a.

[44] TURN DR 9-2.a and TURN DR 9-2.b.

[45] TURN DR 9-2.

[46] TURN DR 9-6.c.

[47] Id. PG&E's full response: "PG&E initially became aware of the homeowner's claim that PG&E's equipment might have played a role in the house fire in 2010 when PG&E was contacted by the homeowner's attorney. However, PG&E's initial investigation concluded that the house fire was likely caused by something other than a failed surge arrestor. The homeowner and his insurance company subsequently filed a lawsuit against PG&E. The parties attended a confidential pre-mediation conference in late 2013 at which plaintiffs' expert presented a case for how a surge arrestor could have caused the house fire. After that meeting, and into early 2014, PG&E reviewed the evidence before ultimately settling the lawsuit through mediation on January 31, 2014. PG&E filed its final Electric Incident Report on February 7, 2014."

failure or if it led to the fire as part of the settlement.[48] Ultimately the settlement cost PG&E the relatively small sum of $402,500.[49]

TURN can understand that PG&E may be concerned about further lawsuits related to the surge arrestors, but a single law suit where no technical determination of root cause was made cannot be the impetus for a 6-year, $105 million program, particularly given the fact PG&E itself has treated this issue as low priority and does not believe that the issue is a significant cause of property damage.

- PG&E's mistaken interpretation of G.O. 95 and the question of ratepayer responsibility

PG&E's support for assigning ratepayer responsibility to the SAG Program consists apparently of the company's introduction and framing of the 1974 "guidance" it received from Commission staff regarding the consistency of its standards change with G.O. 95. In particular, TURN asked PG&E to explain why it began the practice of interconnecting the single-grounded transformer neutrals and surge arrestor grounds; the company responded, "PG&E began the practice…based on the interpretation received from Commission staff that interconnection is permitted under Rule 33.3 (b) of General Order (GO) 95." However, PG&E's response does not actually respond to the question posed regarding why it initially began the practice.[50]

It was PG&E who proposed the practice in the first place; Commission staff offered an interpretation in response to PG&E's proposal that said G.O. 95 permitted the practice. Furthermore, as we saw above, the other major IOUs in the state, SDG&E and SCE, do

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[48] In fact, PG&E does not know whether the surge arrestor failed or even what caused the fire, saying in particular: "During the investigation of the fire, multiple potential ignition sources were identified. PG&E discovered a failed ceramic lightning arrestor which had been on the pole serving the structure that burned. PG&E does not know the root cause of the surge arrestor failure, or whether it caused the house fire." (TURN DR 9-6.g) Moreover, PG&E was not able to do a forensic investigation on the lighting arrestor because it did not retain possession of it (TURN DR 9-6 SuppAtch. 02)—instead the customer's lawyer retained it (TURN. Finally, PG&E has no record of a lightning strike on house's circuit on the date (November 1, 2010) of the fire (Id.).

[49] TURN DR TURN DR 9-6.i.

[50] TURN received a subsequent data response (TURN DR 99-8) that acknowledged PG&E does not know why the company proposed the common grounding of single-grounded secondary neutrals from transformers with tank-mounted surge arrestors.

not practice the common-grounding of single-grounded neutrals with surge arrestors PG&E, however, is downplaying its own responsibility for its practices and is attempting to place all culpability on the Commission's staff. In doing so, the company seeks to assign all of the cost responsibility to ratepayers.

PG&E's position is that it should be excused from the ramifications of an engineering change that the company, itself, made—one which in turn yielded incorrect installations for more than 40 years. However, the fact is that it was PG&E who pushed for this change should give the Commission concern, especially as it relates to ratepayer responsibility. It is not reasonable that ratepayers should be responsible for any or all of the costs for an error in judgment by PG&E. Regardless of the Commission staff's original interpretation of G.O. 95, it was PG&E who proposed the change to its engineering drawings and chose to ground surge arrestors in this fashion and also chose not to place a high priority with respect to addressing the problem when it first became aware of it in 2008. Therefore, ratepayers should not be held wholly responsible even if the Commission were to determine that the staff's original interpretation was on balance more to blame for PG&E's mistake than PGE&E's own action in proposing the changes in the first place.

PG&E must bear some responsibility to correctly interpret its governing orders and implement its construction in conformance with the correct interpretation. Indeed, PG&E is paid a rate return to make correct interpretations and construct its system in accordance with all regulations. The regulated rate of return is intended to account for the risks that PG&E may face for regulatory interpretations and changes at the Commission. The book rate of return should therefore be considered at risk in cases where PG&E fails to make or obtain correct interpretations and/or fails to comply with the correct interpretations. Put another way, it is not reasonable to make ratepayers at all or completely responsible for the incorrect interpretations of general orders whose compliance with the company has the responsibility.

- PG&E's failure to properly comply with the "guidance" it did obtain from Commission staff

As noted in Footnote 31 of this testimony, PG&E changed its standards in cases where arrestors are tank-mounted, even though it had no interpretation from Commission staff

affirming that such practice does not contravene G.O. 95.[51] As such, any tank-mounted arrestor that has a common ground with a single-grounded transformer neutral represents a grounding reconfiguration that should never have been constructed without a spark gap in the first place, as the evidence in this case shows.

The implication of this observation is that, even if the Commission were to decide that ratepayers should be partly or wholly responsible for the corrections at locations that are consistent with the 1974 CPUC staff interpretation, it is not reasonable for the Commission to make ratepayers responsible for those locations for which the staff did not provide an interpretation and which PG&E should not have modified. Indeed, if PG&E had properly followed the Commission's guidance, it at least would not have to now change out common grounds where the arrestor is tank-mounted. The problem, however, is that PG&E has no idea of how many combinations involving tank-mounted arrestors are on its system.[52] Therefore, it impossible to know or estimate how many locations were included in the staff's 1974 interpretation as compared to those locations for which the interpretation had not relevance.[53]

- Forecasting Error

PG&E undertook (and completed) a survey of its system to ascertain the number of common grounds that would require replacement, as noted above. However, the

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[51] The only piece of evidence (i.e., PG&E-issued February 1, 1974 memo) that PG&E was able to produce that directly and specifically spoke to what the Commission's mindset was, says, "It was agreed that the isolating gap presently used on transformer installations protected by lighting arresters, that are not tank mounted, should be eliminated. … The isolating gap will continue to be installed on the transformer tank when arresters are tank-mounted, in accordance with P.G. and E. Drawing No. 015229, Sheet 9." 1974 was indeed a long time ago and a time of poorer records-management capabilities generally, but it is still PG&E's burden to prove that its expressed, 1974 interpretation regarding the applicability—or lack thereof, in this case—of spark gaps to tank-mounted arrestors is not correct and durable. Given that PG&E is not able to produce evidence as to why it may have chosen to or whether the Commission indeed gave it guidance to remove the spark gap from tank-mounted arrestor-transformer combinations, the Commission should assume that CPUC staff gave no such guidance regarding tank-mounted arrestor-transformer combinations.

[52] PG&E did not determine the count through the survey (TURN DR 69-31.d). Furthermore, PG&E does not know how many of each were installed in any year, 1965-2015 (TURN DR 99-1) and does not have any basis to make a general estimate (e.g., say, a 40/60% split, or what have you) because it does not have an asset database with surge-arrestor types (TURN DR 99-3).

[53] TURN DR 69-31.d.

company directed its contractors to count the number of locations where they encountered a common ground, regardless of the secondary-neutral configuration.[54] Any count that results from the contractors' work will, by program design, be an over-estimate of the actual replacement count that PG&E will ultimately execute, given that some portion of the locations with common-ground systems do not actually need to be modified.

It is interesting to note that the surveyors were not instructed to differentiate between types of transformers while surveying, despite the fact that PG&E would not have to correct common-grounds where the transformer neutral is part of a common-ground system. If the Commission were to adopt PG&E's forecast in this case, the company would pocket the money for all locations where the survey (upon which the forecast is based[55]) counted a problematic location, but where in fact the neutral was in a common-neutral system and would need no replacement. There is little comfort in PG&E's assurance that it "does not intend to install separate grounds at these locations."[56] Given that the forecast for this program clearly overestimates problematic locations, any locations that do not need corrective maintenance will be a complete windfall against the test-year forecast for this program.

Furthermore, PG&E did not determine how many locations had tank-mounted vs. how any had arrestors that were not tank-mounted.[57] PG&E does not know, either, how many tank-mounted or non-tank-mounted lighting arrestors it has on its system as a whole, regardless of the grounding configuration.[58] As explained above, this complicates the calculation of any ratepayer responsibility that the Commission may

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[54] TURN DR 69-31.d.

[55] The survey found 95,659 locations with common grounds (TURN DR 9-5.a); PG&E's six-year replacement program, which it uses to determine the 2017 forecast, contains 90,725 replacements (Ex. PG&E-4, p. WP 6-34). The only reason that the GRC forecast is based on a number of replacements that is less than the locations found in the survey is that PG&E made the GRC forecast before completing the survey (Id.).

[56] Id.

[57] TURN DR 69-31.e.

[58] TURN DR 69-22.h. In fact, PG&E cannot even provide estimates (TURN DR 69-9 and TURN DR 69-10).

want to assign, given that it is not reasonable to make ratepayers pay for replacements where the common ground is associated with a tank-mounted transformer.

iii. Recommendations

It would be reasonable for the Commission to remove all funding for this program and any other activities (e.g., corrective steps that are taken through the normal, non-programmatic maintenance), based on the fact that this is a problem of PG&E's making.

However, TURN recommends that the Commission adopt a $4.1 million forecast and subject the costs to a one-way balancing account with certain restrictions regarding the costs that can be booked to the account.

Specifically, PG&E should slow the program so that it corrects common grounds on a 12-year term, rather than a 6-year term. This serves to cut the average annual correction count in half (from 15,131 to 7,566). The forecast should be further reduced by half (to 3,783 corrections) to account for the fact that some—PG&E does not know how many—of the locations that PG&E found through the survey will not actually need correction because the secondary neutrals will be in a common-ground system.[59] With PG&E's unit cost forecast of $1,077, the total forecast would be $4.100 million after rounding. Furthermore, TURN recommends that any costs for correcting a tank-mounted arrestor configuration be excluded from recovery through the balancing account, and should rather be booked below the line. Finally, 80% of the cost of any correction that is allowed in the balancing account—i.e., those where the transformer's secondary neutral is single-grounded and where the arrestor configuration is not tank-mounted—should also be booked above the line. The other 20% should be booked below the line and not included in the balancing account. This last recommendation reflects the fact that this is a problem of PG&E's making.

In sum, any annual costs that are above the one-way balancing account limit in any year and 20% of the cost of any given balancing account-allowed project should be booked below the line.

[59] Fifty percent is a reasonable approximation, given that PG&E has does not know, but could have found out through the survey, how many of the survey results will need correction.

Table 1 provides a breakdown of the mechanics of this calculation.

Table 1: Breakdown of TURN's Recommendation for the SAG Program

15,131	Avg. annual correction count over 6 years (PG&E's assumption)
7,566	Avg. annual installation over 12 years (TURN's assumption, results in 50% of PG&E's average annual annual count.
3,783	50% of annual installations to account for the fact that some of the secondary neutrals will be in common-ground systems and will not need correction; PG&E does no t know how many this is, so an estimate of 50% is reasonable.
$1,077	Unit Cost (Ex. PG&E-4, p. WP 6-9)
$4,100,000	Recommended test-year funding level (rounded from $4.07MM). Only non-tank-mounted-configuration grounding corrections can be booked here, and the cost of the non-tank-mounted conficuation can only be booked at 80% of the actual cost of the correction.

Finally, if the Commission adopts any non-zero forecast for this subprogram, whether it's TURN's or another, it should order PG&E to account for any spending in one-way balancing account that sets a cap and refunds any unspent funds to ratepayers.

D. Electric Distribution Reliability (Chapter 9)

1. Base Reliability (MWC 08) and Circuit/Zone Reliability (MWC 49)

PG&E forecasts Test Year 2017 spending of $131.2 million for reliability-related programs, or $407.6 million over the three-year, rate-effective period,[60] which is an average of $135.9 per year. ORA recommends that the Commission not take any adjustment to the Reliability program.[61]

TURN recommends a reduction of $14.265 million for MWC 08 and $20.780 million for the test year as follows:

[60] Calculated from PG&E-4 WPs, p. WP 15-4 (line 5).

[61] Ex. ORA-11, p. 3.

Testimony of Garrick F Jones in Pacific Gas and Electric Company's 2017 Test Year General Rate Cases

Attachments to Testimony

Prepared testimony of
Garrick F Jones

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On behalf of
The Utility Reform Network (TURN)

California Public Utilities Commission
Docket # A.15-09-001

April 29, 2016

Revised May 24, 2016

C. Electric Distribution Issues: Electric Distribution Maintenance (Chapter 6)

TURN DR 9-2.
TURN DR 9-2 Atch. 02
TURN DR 9-3 Atch. 01
TURN DR 9-3 Atch. 02
TURN DR 9-5.
TURN DR 9-6
TURN DR 9-6 Supp. Atch. 02
TURN DR 28-1
TURN DR 69-4
TURN DR 69-9
TURN DR 69-10
TURN DR 69-19
TURN DR 69-22
TURN DR 69-22 Atch. 03
TURN DR 69-22 Atch. 09
TURN DR 69-25
TURN DR 69-31
TURN DR 99-1
TURN DR 99-3

Additional Documents Relied Upon
Surge Arrester Grounding, Briefing for SED (04/22/14), p. 2. PUC Legal Division provided the document to TURN on March 11, 2016 in response to Public Records Act Request (PRAR), Ref. No. PRA #1913.

PACIFIC GAS AND ELECTRIC COMPANY
2017 General Rate Case Phase I
Application 15-09-001
Data Response

PG&E Data Request No.:	TURN_009-Q02		
PG&E File Name:	GRC-2017-PhI_DR_TURN_009-Q02		
Request Date:	October 21, 2015	Requester DR No.:	009
Date Sent:	November 4, 2015	Requesting Party:	The Utility Reform Network
PG&E Witness:	Greg Kiraly	Requester:	Hayley Goodson

EXHIBIT REFERENCE: PG&E-4, CHAPTER 6 (ELECTRIC DISTRIBUTION MAINTENANCE)

SUBJECT: SURGE ARRESTOR GROUNDING PROGRAM

QUESTION 2

Referencing PG&E's statement on p. 6-35 of the testimony, "This will reduce the risk of equipment and property damage and will ensure PG&E's compliance with current regulatory guidance."

a. Please provide any and all reports, analysis, etc., that qualify and/or quantify the risk (both in frequency and magnitude of the consequences) of PG&E equipment failure caused by "common grounding" of surge arrestors and transformers.

b. Please provide any and all reports, analysis, etc., that qualify and/or quantify the reduction in risk (in frequency and magnitude of consequences) of PG&E equipment failure caused by separately grounding surge arrestors and transformers.

c. Please provide documentation of the "current regulatory guidance" to which PG&E refers in this statement.

ANSWER 2

a. Common grounding of surge arrestors and transformers is not a significant cause of PG&E equipment failure, so PG&E has not performed the analysis described. PG&E interprets this question as requesting reports, analysis, etc. that qualify and/quantify the risk (both in frequency and magnitude of the consequences) of damage to customer property due to "common grounding" of surge arrestors and transformers.

   PG&E objects to this question on the grounds that it requests documents covered by the attorney-client privilege and/or attorney work product doctrine. Subject to and notwithstanding that objection, PG&E is producing a PowerPoint from 2010 titled "Identifying and Correcting Surge Arrester Grounding" which contains a discussion of risks. See attachment GRC-2017-PhI_DR_TURN_009-Q02Atch01.

b. Common grounding of surge arrestors and transformers is not a significant cause of PG&E equipment failure, so PG&E has not performed the analysis described. PGE

interprets this question as requesting reports, analysis, etc. that qualify and/quantify the reduction in risk (both in frequency and magnitude of the consequences) of damage to customer property due “common grounding” of surge arrestors and transformers.

PG&E objects to this question on the grounds that it requests documents covered by the attorney-client privilege and/or attorney work product doctrine. Subject to and notwithstanding that objection, PG&E is producing a PowerPoint from 2010 titled “Identifying and Correcting Surge Arrester Grounding” which contains a discussion of risks. See attachment GRC-2017-PhI_DR_TURN_009-Q02Atch01.

c. The “current regulatory guidance” PG&E referred to in testimony is the Commission’s interpretation of Rule 33.3B of General Order No. 95 contained in an October 12, 2007 letter from Commission to PG&E. See attachment GRC-2017-PhI_DR_TURN_009-Q02Atch02.

ATTACHMENT 7

TURN'S CALCULATION OF HELICOPTER COST, NORMALIZED OVER THE TOTAL NUMBER OF FORECASTED POLE REPLACEMENTS IN 2023 AND PG&E'S RESPONSE TO TURN DR 21-2 AND ATTACHMENT 1 FROM THE 2020 GRC



Calculation of Helicopter Cost, Normalized Over the Total Number of Forecasted Pole Replacements in 2023.

Line	Category	Values	Equations	Sources and Assumptions
(a)	2023 Pole Replacement Unit Count Forecast	15,964		Ex. PG&E-4, WP 12-22:16.
(b)	Net Pole Replacement Unit Count in Rugged Terrain	1,498		Average number of replacements in rugged terrain in 2018-2021 (i.e., 2,144), net of the average in 2016-2017 (i.e., 647), per TURN DR 180-1b.
(c)	Cost / Flight hr.	$8,599		Per-flight-hour cost charged to LOBs in 2017 for PG&E-owned helicopter, escalated to 2023$. Includes fixed and variable costs. Based on rate PG&E provided in TURN DR 21-2-Atch01, provided in the 2020 GRC, escalated to 2023$ using information in TURN DR 21-10-Atch01 in the instant case. Note: cost in 2017$ is $7,004.
(d)	Hours of flight time per pole	0.50		Judgemental Assumption -- based on a conservatively applying industry experience. French Broad Electric Membership Coop set 12 poles and attached the wire in just over 3 hours, which calculates to no more than 0.25 hours per pole (i.e., 3 / 12). TURN's assumption of 1/2 hour per pole is conservative, therefore. *See* source-company video at www.youtube.com/watch?v=RlCAw7V3cKk (at 0:28 and 5:24).
(e)	Cost of helicopter use per pole in Rugged Terrain	$4,299	(f) = (d) / (e)	
(f)	Cost of Helicopter Use, Normalized Across Systemwide Pole-Replacement Forecast per pole	$403	(g) = (f) x [(c) / (a)]	

The table relies upon PG&E's response to TURN DR 21-2 and Attachment 1 from the 2020 GRC, which are included in the pages that follow this page.

PACIFIC GAS AND ELECTRIC COMPANY
2020 General Rate Case Phase I
Application 18-12-009
Data Response

PG&E Data Request No.:	TURN_021-Q02		
PG&E File Name:	GRC-2020-PhI_DR_TURN_021-Q02		
Request Date:	May 8, 2019	Requester DR No.:	021
Date Sent:	May 30, 2019	Requesting Party:	The Utility Reform Network
PG&E Witness:	James Kent	Requester:	Marcel Hawiger

SUBJECT: SHARED SERVICE AND INFORMATION TECHNOLOGY EXHIBIT (PG&E-7)

Transportation and Aviation Services (Chapter 2)

QUESTION 02

Re. Table 2-12 on p. 2-31:

a. Please disaggregate each of the Usage costs in Table 2-12 on p. 2-31 of the testimony into Usage costs for (i) chargebacks to PG&E LOBs and (ii) reimbursements from CAL FIRE for utilizing the helicopters.

b. Please provide evidence that PG&E netted out the historical operational and rental costs associated with heavy lift helicopter from forecasted costs for the LOBs with forecasted chargeback-related costs.

c. What is/are the reason(s) for the difference in the Operating Costs between Aircraft #1 and Aircraft #s 2-4?

d. Why are the Usage values equal among the four aircraft, given that PG&E expects to be the sole user of one aircraft and provide CAL FIRE with utilization of three helicopters during the fire season?

ANSWER 02

a. See attachment GRC-2020-PhI_DR_TURN_021-Q02Atch01.

   i. See columns P through R of the attachment for PG&E chargebacks.

   ii. See columns T through V of the attachment for revenue from CAL FIRE for utilizing the helicopters.

b. The PG&E chargeback cost forecast is based on the historic contract cost of helicopter usage. See columns P through R of attachment GRC-2020-PhI_DR_TURN_021-Q02Atch01.

c. Aircraft #1 is staffed 365 days per year, Aircrafts #2, #3 and #4 are staffed 215 days per year, or 7 days a week starting on May 1 through November 30 for fire season

coverage.

d. PG&E does not expect to be the sole user of any one of the aircrafts. Helicopter availability is based on the total number of helicopters and not by specific tail number. All four helicopters will be used by PG&E for construction and restoration work throughout the year. During fire season, between May 1 to November 30, PG&E intends to make at least 3 helicopter assets available to CAL FIRE to assist with fire response, subject to PG&E's construction and restoration efforts during this time. PG&E believes that this will provide helicopter asset coverage while accounting for scheduled and unscheduled maintenance. For maintenance and budgeting reasons, PG&E intends to keep the aircrafts close in total number of flight hours per year. The aircrafts will be rotated to ensure consistent hours are applied to each aircraft.

Annual Heavy Lift Helicopters

(In Thousands

Line No		Availability (Will-call) (Fixed)			Overall Flight Hours (Variable)		
1							
2	**Aircraft**	**Days**	**Daily Contract Rate[1]**	**Cost**	**Hours[3]**	**Hourly Contract Rate[1]**	**Cost**
3	Aircraft #1	365	$7.8	$2,845	300	$2.7	$797
4	Aircraft #2	215	$7.8	$1,676	300	$2.7	$797
5	Aircraft #3	215	$7.8	$1,676	300	$2.7	$797
6	Aircraft #4	215	$7.8	$1,676	300	$2.7	$797
7	Hangar						
8	**Total**	**1,010**		**$7,873**	**1,200**		**$3,186**
9							
10	Notes:						
11	[1]The daily contract rate was the preliminary contract rate provided by the vendor during contract negotiations.						
12	[2]Assumed annual cost of Phase 2 inspections that occur every 530 flight hours.						
13	[3]PG&E assumed a usage of 300 hours per aircraft for a total of 1,200 total hours per year. The usage between PG&E and CAL FIRE was allocated						
14	[4]The rate was calculated by taking the average price PG&E paid historically to vendors for heavy lift helicopters and escalated by 3% (see comm						
15	[5]CAL FIRE "Call When Needed" contract payment to PG&E was assumed to be $9.3K/hr at the time of the forecast.						
16							
17	**Heavy Lift Helicopters - Contract Average Rate / Hour**						
18							
19	**Year**	**Cost**	**Flight Hours**	**Avg Rate**			
20	2015 - Recorded	$604	86	$7.0/FH			
21	2016 - Recorded	$586	92	$6.3/FH			
22	2017 - Recorded	$2,835	411	$6.9/FH			
23	**Total**	**$4,024**	**589**	**$6.8/FH**			
24	Note: The average actual rate for 2015 - 2017 of $6,832 was escalated by 3% ($7,037). This rate is used to estimate PG&E chargeback and CAL F						

(Black Hawk) Operating Cost Forecast

s of Nominal Dollars)

Other Fixed Costs[2]	Total Operating Costs	PG&E Chargeback Hrs[3]	PG&E Chargeback Rate[4]	PG&E Chargeback Cost	CAL FIRE Revenue Hrs[3]	CAL FIRE Revenue Rate[5]	CAL FIRE Revenue Cost	Chargeback + Revenue	Total Operating Costs - (Chargeback + Revenue)
$39	$3,680	125	$7	$876	175	$9.3	$1,622	$2,498	$1,183
$39	$2,511	125	$7	$876	175	$9.3	$1,622	$2,498	$13
$39	$2,511	125	$7	$876	175	$9.3	$1,622	$2,498	$13
$39	$2,511	125	$7	$876	175	$9.3	$1,622	$2,498	$13
	$52								$52
$155	**$11,265**	**500**		**$3,502**	**700**		**$6,489**	**$9,991**	**$1,274**

d based on judgement and historic use.

ents in line 27).

IRE revenue amount in the table above.

ATTACHMENT 8

EXCERPT OF THE DIRECT TESTIMONY OF GARRICK F. JONES (EX. TURN-03) FROM PG&E'S 2017 GRC (REGARDING THE CIRCUIT BREAKER AND SWITCHGEAR REPLACEMENT PROGRAMS)



Exhibit Number TURN-3

Testimony of Garrick F Jones in Pacific Gas and Electric Company's 2017 Test Year General Rate Cases

Prepared testimony of
Garrick F Jones

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tel. 916.372.0534

On behalf of
The Utility Reform Network (TURN)

California Public Utilities Commission
Docket # A.15-09-001

April 29, 2016

Revised July 27, 2016

PG&E requested 175.0 million for the test year of the 2014 GRC and forecasted at total of $554.3 million for the 2014 GRC rate-effective period,[179] and the Commission authorized its test year request. The ORA had recommended a forecast of $142.6 million for 2014. PG&E actually spent just $100.0 million in 2014[180] (and $133.1 million in 2015), and expects to spend just $376.1 million during 2014-2016.[181]

The Commission should not continue to rely on PG&E's excessive forecasts for SAM spending. PG&E has overforecast and underspent significantly in 2011-2016. The Commission should not continue to let PG&E get the benefit of excessive forecasts embedded in revenue requirements. In the event that PG&E does ultimately pick up the spending pace for the SAM program, it will be able to roll in all reasonable capital spending into rate base in the 2020 GRC rate period.

3. Replace Substation Equipment (MWC 48)

a. Switchgear Replacement (MAT Code 48F)

i. Introduction

PG&E forecasts $63.1 million for the Test Year;[182] ORA does not recommend a reduction.

PG&E attempts another reset to this program, claiming a new, "current approach to switchgear projects [that] incorporates lessons learned from completed projects… ."[183] However, PG&E also "rescheduled switchgear projects originally forecast in the 2011 GRC… [in order] to leverage lessons learned… ." PG&E also claims that some of the projects forecasted for 2014 were "not completed as originally forecast in order to fund higher priority work."[184]

The following contains a more detailed history.

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[179] 2014 GRC, Ex. PG&E-4, p. WP 13-8 (WP 13-8).

[180] Ex. PG&E-4, p. WP 12-11 (WP Table 12-9).

[181] Id.

[182] Ex. PG&E-4, p. WP 12-22 (WP Table 12-18).

[183] Id., p. 12-5 (lines 24-25).

[184] Id., p. 12-16 (lines 15-17).

ii. History of underspending

The Commission adopted[185] PG&E's entire Test Year 2014 forecast of $43.0 million in the last rate case;[186] however, the 2014 recorded expenditure was $19.4 million and PG&E spent even less in 2015 ($28.3 million) than it forecasted in this 2017 GRC filing ($35.4 million). PG&E had forecast total spending of $166.4 million for 2014-2016 in the last rate case, but PG&E now expects to have spent just $104.9 million in 2014-2016.[187] Even that figure is likely much to high, since PG&E forecasts spending $23.9 million in 2016, while average spending in 2014-2015 was $23.9

Indeed, ORA recommended $33.6 million for the 2014 test year in the last rate case, and the average 2014-2015 recorded spending was just $23.9 million, almost $10 million less than ORA's forecast. ORA stated in part the following to support its forecast in the last GRC:

> In the 2011 GRC, PG&E sought to undertake 14 switchgear replacement projects over the period 2009 through 2013. In the current 2014 GRC, PG&E states in its testimony that only two of the switchgear projects proposed during the last GRC were actually completed.[Footnote omitted] Indeed, a close inspection of the projects proposed (and authorized) in the 2011 GRC shows that 11 of the replacement projects are being requested again in the current GRC. In its testimony, PG&E states that it decided to reschedule the original 2011 switchgear projects so that it could apply lessons learned from the two projects that it did complete.[Footnote omitted] More specifically, PG&E states that rather than pursuing multiple switchgear projects simultaneously as originally planned in the 2011 GRC, it decided to wait to complete and learn from the Mission Substation project, and then leverage lessons learned from that project to the other switchgear projects.
>
> …
>
> For 2014, PG&E is proposing to work on 13 switchgear projects simultaneously. This request is ambitious. PG&E's 2014 forecast of $42.962 million is more than 50% higher than the previous largest recorded expenditure ($28.125 million in 2011). In DRA's judgment, a

[185] D.14-08-032, p. 225.

[186] 2014 GRC, Ex. PG&E-4, p. WP 13-14 (WP Table 13-12).

[187] $104.9 million = $19.4 million + $28.3 million + $57.2 million, the arguments of which come, respectively from PG&E-4 (p. 12-22), ORA Oral 25 Atch01, and Ex. PG&E-4 (p. 12-22).

> more reasonable forecast for 2014 is the $33.588 million forecast proposed by PG&E (and accepted by DRA) for 2013.[188]

In D.14-08-032, the Commission disagreed with ORA, stating:

> We conclude that PG&E's forecast for SAS capital expenditures is appropriate and is adopted. We appreciate DRA's concern that the scope of the project appears overly ambitious. We agree with PG&E, however, that beginning work on these three additional projects in 2014 is appropriate because it takes several years to develop and execute a switchgear project. PG&E's forecast will allow a balance of switchgear projects in various phases of the project cycle so that PG&E can better plan and manage resources to efficiently execute switchgear projects going forward. PG&E decided to reschedule most of the switchgear projects originally forecast in the 2011 GRC until it had completed the Mission substation project in order to leverage lessons learned from that project. The project work scheduled for 2014 to 2015 reflects those lessons learned.[189]

As noted, PG&E is again, at least implicitly in the current GRC, using "lessons learning" as an excuse for not undertaking the switchgear projects it has forecasted in earlier GRCs. However, while PG&E talks about "lessons learned" in the past tense in this application, the company spent just $28.3 million in 2015, the year PG&E spoke of its "current approach", which was based on those "lessons learned".

On the other hand, PG&E may well have had to delay some of the project work on the basis of higher priority work, as the company indicates. However, this excuse appears strained, given that PG&E also states regarding its postponement of circuit breaker projects (discussed below), "…circuit breaker projects were rescheduled and/or reprioritized in the 2015 to 2019 timeframe to focus on completing switchgear projects."[190]

Either way, the lack of spending suggests that ORA was correct when it said that PG&E's 2014 switchgear forecast was ambitious. Instead of the 13 projects that PG&E

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[188] 2014 GRC, Ex. ORA-7, pp. 46 (starting at line 12) – 47.

[189] D.14-08-032, p. 225.

[190] Ex. PG&E-4, p. 12-17 (lines 22-24).

said it would work on in 2014 alone[191], or even the 10 that ORA's 2014 forecast implied,[192] PG&E has thus far only completed three in the 2014 GRC period.[193]

iii. Recommendation

Until PG&E shows that it has the capacity to manage and implement switchgear-replacement projects on the scale it proposes in this GRC, the Commission should limit the GRC forecast. TURN recommends that the Commission adopt a 2017 forecast of $27.344 million, which is the average of the last six years (i.e., 2010-2015). If PG&E ultimately has the capacity to undertake a more ambitious program such spending will be rolled into rate base. This corresponds to a reduction of $35.740 million.

b. Circuit Breaker Replacement (MAT 48D)

i. Analysis

PG&E forecasted and the Commission adopted[194] $9.0 million for test year 2014 to replace 30 breakers (equal to $27.0 million for the rate-effective period, not including escalation);[195] PG&E recorded just $4.4 million in 2014, and expects to record just $16.6 million in 2014-2016, which is $9.4 million less than authorized.

PG&E states that "circuit breaker projects were rescheduled and/or reprioritized in the 2015 to 2019 timeframe to focus on completing switchgear projects."[196] However, PG&E spent just $4.359 million in 2014 (before the alleged focus on switchgear), and, as discussed above, PG&E spent less than half of its authorized forecast in 2014-2015 on switchgear projects and claimed that "some of the switchgear projects originally forecast

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[191] 2014 GRC, Ex. PG&E-4, p. WP 13-19.

[192] Id., Ex. DRA-7, pp. 46 (lines 24-25) – 47 (lines 3-5 and 9-10).

[193] As of September 15, 2015, when PG&E filed its testimony. While PG&E lists five completed switchgear in Ex. PG&E-4 (p. WP 12-28) of the instant case, PG&E had completed two of them (i.e., Mission Substation and Oakland C Substation) as of the 2014 GRC filing (2014 GRC, Ex. PG&E-4, p. WP 13-19).

[194] D.14-08-032, p. 225.

[195] 2014 GRC, PG&E-4, p. 13-11 (lines 7-10).

[196] Ex. PG&E-4, p. 12-17 (lines 22-24).

in the 2014 GRC were not completed as originally forecast in order to fund higher priority work."[197]

ii. Recommendation

The six-year average forecast is close to PG&E's forecast for this subprogram.[198] Therefore, TURN has not monetary recommendation. Rather, we emphasize problems with PG&E's historical spending. The Commission should consider the fact that PG&E apparently blames its underperformance within the Circuit Breaker Replacement program on a "focus on completing switchgear projects," as we have already covered, when PG&E spent less than half of its authorized forecast in 2014 and 2015 on switchgear projects and claimed that "some of the switchgear projects originally forecast in the 2014 GRC were not completed as originally forecast in order to fund higher priority work."[199] This is one example of the greater problem with "reprioritization" and deferred maintenance.

c. Animal Abatement (MAT 48X)

i. Introduction and Analysis

PG&E forecasts $2.1 million for Animal Abatement;[200] ORA accepts the forecast.

In the last rate case the Commission authorized $3.6 million per year in funding to do this work, but PG&E spent just $2.554 million in 2014 and 439k in 2015, and forecasts spending $165k in 2016.[201] In response to TURN's data request asking PG&E to explain why the 2014 GRC-cycle animal-abatement activity was lower than authorized, the company states:

> PG&E slowed implementation rates in 2015 and 2016 because fewer remaining sites were left to abate that had a prior animal contact. The Animal Abatement initiative originally began targeting substations that experienced any animal contacts resulting in substation related outages in 2009. ... During this time, PG&E revised its engineering standards to

[197] Ex. PG&E-4, p. 12-16 (lines 15-17).

[198] The six-year (2010-2015) average is $6.9 million. Calculated from PG&E-4, p. WP 12-22.

[199] Ex. PG&E-4, p. 12-16 (lines 15-17).

[200] Ex. PG&E-4, p. WP 12-22.

[201] Ex. PG&E-4, p. WP 12-22 and ORA ORAL 25 Atch01.

ATTACHMENT 9

PG&E DATA RESPONSES EXPLICITLY RELIED UPON FROM THE 2023 GRC



PACIFIC GAS AND ELECTRIC COMPANY
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Data Response

PG&E Data Request No.:	CalAdvocates_117-Q15		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_117-Q15		
Request Date:	October 21, 2021	Requester DR No.:	PubAdv-PG&E-117-GAW
Date Sent:	November 5, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Mark Esguerra	Requester:	Greg Wilson

SUBJECT: POLE ASSET MANAGEMENT QUESTIONS

Cal Advocates is seeking clarity and additional information regarding various aspects of PG&E's Pole Asset Management testimony. Please provide the following information:

QUESTION 15

On lines 13 through 15 of page 12-28 of exhibit PG&E-4, PG&E states the following regarding the need to hire outside contractors:

> PG&E has had to hire additional contractors from outside the Company to execute the growing volume of pole replacements, which increases overall program costs.

The following questions are designed to provide additional information in order to improve Cal Advocates' understanding of the above quotation:

a. In PG&E's recent Wildfire Mitigation and Catastrophic Event (WMCE) proceeding (A.20-09019), PG&E testified that outside contractors worked on a "6/12 schedule," meaning that contractors were available to work 6 days per week, 12 hours per day. Do the outside contractors in this current PG&E GRC proceeding also work on a 6/12 schedule?

b. If PG&E's answer to Question 15.a is "No," please provide information regarding the days/hours typically worked.

c. Based on the quotation provided above, it is apparent that additional outside contractors caused an increase in the overall pole replacement costs. Please quantify the total additional costs (as compared to the total costs that would have been incurred had extra outside contractors not been needed) that were incurred due to the necessity of hiring these extra outside contractors.

ANSWER 15

a. No, the forecast does not include an assumption regarding a specific work schedule. PG&E's pole replacement program forecast costs are based on the volume of poles to be replaced in each division multiplied by the average division unit costs. The average division unit costs are based on the prior three-year average (2018 to 2020). PG&E's forecast costs are not broken down by internal and external contract labor.

b. The forecast does not include an assumption regarding a specific work schedule.

c. The costs incurred with hiring external contractors are incorporated into the overall costs for the individual pole replacements. PG&E does not separately track costs for pole replacements performed by internal labor vs. external labor, so cannot quantify additional costs incurred by hiring extra outside contractors.

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PG&E Data Request No.:	CalAdvocates_173-Q05		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_173-Q05		
Request Date:	November 30, 2021	Requester DR No.:	PubAdv-PG&E-173-GAW
Date Sent:	December 14, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Mark Esguerra	Requester:	Greg Wilson

SUBJECT: FOLLOW-UP TO PG&E'S RESPONSES TO DATA REQUEST PUBADV-PG&E-117-GAW

Cal Advocates is seeking additional information regarding several of the responses that PG&E previously provided to data request PubAdv-PG&E-117-GAW. Please provide the following information:

QUESTION 05

In PG&E's response to data request Question 15.a of data request PubAdv-PG&E-117-GAW, PG&E states that "*The average division unit costs are based on the prior three-year average (2018 to 2020).*" In PG&E's workpapers for Chapter 12 of Exhibit PG&E-4, PG&E has provided Workpaper Table 12-20 on page WP 12-20. That table appears to show the details for the calculation of pole replacements, broken down into the costs for each division. However, Cal Advocates has not been able to calculate the forecast unit costs for each division using recorded data from 2018 to 2020. Stated another way, it does not appear that the divisional unit costs shown on that table are based on the prior three-year average (2018 to 2020).

a. For each of the years 2021, 2022 and 2023, please provide and explain the calculations that are necessary to derive the forecasts for "Units" and "Dollars" for each of the Divisions listed in Workpaper Table 12-20.

b. If these calculations require the use of various assumptions and/or various escalation rates, please provide those assumptions and rates.

ANSWER 05

a. For the 2021 forecast, PG&E used the 2017-2019 divisional averages. For the 2022 and 2023 forecasts, PG&E used the 2018-2020 divisional averages. The 2019 and 2020 unit costs were higher due to contractor costs, acceleration of work in High Fire Threat Districts and unanticipated adders (e.g. required use of a helicopter, crane or other heavy equipment to set a new pole) and overtime. In efforts to minimize adders and gain efficiencies due to higher forecast units,

PG&E decreased the divisional averages. In addition, PG&E considered the Electric Distribution escalation rates detailed in subpart b (below).

b. See response to subpart a (above). In addition, PG&E considered the Electric Distribution escalation rates as follows:
   - 2021 = 2.8%
   - 2022 = 2.6%
   - 2023 = 2.7%

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PG&E Data Request No.:	CalAdvocates_173-Q07		
PG&E File Name:	GRC-2023-PhI_DR_CalAdvocates_173-Q07		
Request Date:	November 30, 2021	Requester DR No.:	PubAdv-PG&E-173-GAW
Date Sent:	December 14, 2021	Requesting Party:	Public Advocates Office
PG&E Witness:	Mark Esguerra	Requester:	Greg Wilson

SUBJECT: FOLLOW-UP TO PG&E'S RESPONSES TO DATA REQUEST PUBADV-PG&E-117-GAW

Cal Advocates is seeking additional information regarding several of the responses that PG&E previously provided to data request PubAdv-PG&E-117-GAW. Please provide the following information:

QUESTION 07

In PG&E's response to data request Question 15.c of data request PubAdv-PG&E-117-GAW, PG&E states:

c. The costs incurred with hiring external contractors are incorporated into the overall costs for the individual pole replacements. PG&E does not separately track costs for pole replacements performed by internal labor vs. external labor, so cannot quantify additional costs incurred by hiring extra outside contractors.

MAT	Year	Contract Unit Cost	Units	Total Dollars	Increase in 2019 Cost
07D	2018	$22,133	5690	$ 125,937,895	
07D	2019	$54,348	1663	$ 90,380,471	**$53,572,963**
07O	2018	$28,488	33	$ 940,088	
07O	2019	$36,495	14	$ 510,931	**$112,106**
17B	2018	$11,795	218	$ 2,571,326	
17B	2019	$18,132	180	$ 3,263,739	**$1,140,626**
2AA	2018	$8,775	3586	$ 31,466,724	
2AA	2019	$12,803	7640	$ 97,818,213	**$30,778,121**
2AB	2018	$3,240	36	$ 116,627	
2AB	2019	$19,501	5	$ 97,507	**$81,309**
2AF	2018	$5,659	265	$ 1,499,604	
2AF	2019	$14,439	37	$ 534,237	**$324,858**

**For 2019, units and dollars are reflective of only the incremental work completed for MATs 07D, 07O, 17B, 2AA, 2AB, and 2AF*

As shown in the first two lines in the above Excel table, PG&E was able to quantify how the "Contract Unit Cost" (shown in the third column) changed from 2018 to 2019 for MAT 07D. The fourth column also shows the number of "Units" that were undertaken by the contractors.

a. Please explain why PG&E was able to determine "Contract Unit Costs" for its WMCE proceeding but cannot do so in this current proceeding.

b. Please explain why PG&E was able to determine the number of MAT 07D pole replacements undertaken by contractors for its WMCE proceeding but cannot do so in this current proceeding.

ANSWER 07

a. PG&E determined the volume of pole replacements executed in 2020 in MAT 07D that were performed by Contractors. The details are in the table below:

MAT	Year	Contract Unit Cost	Units	Total Dollars
07D	2020	$ 26,399	6,538	$ 175,730,422

b. See response to subpart a (above).

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PG&E Data Request No.:	TURN_021-Q02		
PG&E File Name:	GRC-2023-PhI_DR_TURN_021-Q02		
Request Date:	September 21, 2021	Requester DR No.:	TURN-PG&E-21
Date Sent:	October 5, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Hayley Goodson

SUBJECT: POLE MANAGEMENT

QUESTION 02

Re. Excel WP Table 12-20:

a. Please add a column which identifies whether each "division" (column B) is primarily located in a Tier 1 HFTD, Tier 2 HFTD, or non-HFTD area.

b. Please create a copy of this Table in Excel that includes just units and costs recorded by PG&E to its WMPMA in 2020 and for which the utility seeks recovery in Chapter 12, Attachment A (shown in Table 12-1 on p. 12-AtchA-4). Please provide all supporting workpapers in Excel.

ANSWER 02

a. Please see attachment titled, "GRC-2023-PhI_DR_TURN_021-Q02Atch01"

   Per CPUC Decision 17-12-024 (Fire Safety Rulemaking), the High Fire Threat Districts (HFTDs) are designated as Tier 2 and Tier 3. There does not exist a Tier 1 HFTD. All areas that are not Tier 2 or Tier 3 are designated non-HFTD. PG&E will use non-HFTD, Tier 2 HFTD and Tier 3 HTFD nomenclature in this response.

   PG&E has approximately 2.3 million wood poles located throughout northern and central California. The term "primarily" is ambiguous and not defined. PG&E has provided pole count information per Division and non-HFTD, Tier 2 HFTD and Tier 3 HTFD from the Electric Distribution Geographic Information System (EDGIS) as of Thursday, September 23, 2021.

b. Based upon the October 1, 2021 Scoping Memo for this proceeding, the reasonableness reviews of costs recorded to the WMPMA and FRMMA has been moved from Track 1 to Track 2. As a result, this request is outside the scope of Track 1. PG&E will address questions pertaining to Track 2 after the initiation of Track 2.

Division	Non-HFTD	Tier 2 HFTD	Tier 3 HFTD	Total Pole Count	Non-HFTD %	Tier 2 HFTD %	Tier 3 HFTD %
Cental Coast	92,779	19,773	19,486	132,038	70%	15%	15%
De Anza	37,916	4,003	6,153	48,072	79%	8%	13%
Diablo	49,745	6,906	2,685	59,336	84%	12%	5%
East Bay	49,755	6,666	2,409	58,830	85%	11%	4%
Fresno	245,633	18,173	805	264,611	93%	7%	0%
Humboldt	61,744	56,156	8,949	126,849	49%	44%	7%
Kern	135,559	2,751	0	138,310	98%	2%	0%
Los Padres	68,116	29,237	5,857	103,210	66%	28%	6%
Mission	50,569	4,083	2,299	56,951	89%	7%	4%
North Bay	50,437	11,248	16,004	77,689	65%	14%	21%
North Valley	121,075	72,192	27,316	220,583	55%	33%	12%
Peninsula	53,138	8,806	2,352	64,296	83%	14%	4%
Sacramento	105,909	3,460	0	109,369	97%	3%	0%
San Francisco	31,425	0	0	31,425	100%	0%	0%
San Jose	55,295	5,012	842	61,149	90%	8%	1%
Sierra	83,455	85,744	49,333	218,532	38%	39%	23%
Sonoma	53,498	19,194	16,536	89,228	60%	22%	19%
Stockton	113,749	35,384	14,798	163,931	69%	22%	9%
Yosemite	178,208	49,930	19,002	247,140	72%	20%	8%
Total Pole Counts	**1,638,005**	**438,718**	**194,826**	**2,271,549**			
	72%	19%	9%				

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PG&E Data Request No.:	TURN_021-Q10		
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Date Sent:	October 5, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Hayley Goodson

SUBJECT: POLE MANAGEMENT

QUESTION 10

In Excel, please provide escalation rates to 2020 for capital costs from 2016-2019, annually.

ANSWER 10

See attachment GRC-2023-PhI_DR_TURN_021-Q10Atch01.

Line No.	Year	Electric Dist.
1	2016	1.60%
2	2017	3.30%
3	2018	3.10%
4	2019	5.80%
5	2020	3.30%
6	2021	2.80%
7	2022	2.60%
8	2023	2.70%

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PG&E Data Request No.:	TURN_024-Q03		
PG&E File Name:	GRC-2023-PhI_DR_TURN_024-Q03		
Request Date:	September 21, 2021	Requester DR No.:	TURN-PG&E-24
Date Sent:	October 5, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Hayley Goodson

SUBJECT: PG&E-4 (ELECTRIC DISTRIBUTION), CHAPTER 13 (ASSET MANAGEMENT & RELIABILITY)

QUESTION 03

Data Requests – PG&E-4, Chapter 13 (OH and UG Asset Management and Reliability)

Re. p. 13-40 (lines 2-4), PG&E states, "There were approximately 459 reports of failed LBOR oil switches between 2000 and 2017, some of which were reported to have high-energy failures."

a. Please define "high-energy failures" as used by PG&E here.

b. Please identify the number of reported failed LBOR oil switches in each year, 2000-2021 (year to date), disaggregated between those that were and were not of a "high-energy" nature.

c. Of the "high-energy" failures identified in Part a of this request, please indicate how many per year were associated with switches that were "manufactured in the 1970s or 1980s" (per p. 13-40, line 5).

d. Of the "high-energy" failures identified in Part a of this request, please indicate how many per year were associated with switches that were manufactured prior to 1975.

e. Please indicate how many of the failed LBOR oil switches between 2000 and 2021 were associated with pre-1975 switches without oil inspection sight glasses.

ANSWER 03

a. The term high-energy failure refers to the type of failure, which includes, but is not limited to explosion, fire, enclosure damage, or smoke.

b. PG&E objects to the request on the ground that it is overbroad as to time and unduly burdensome. In addition, PG&E objects to the request to the extent it seeks information beyond the scope of this proceeding. The testimony cited in the question provides background regarding LBOR switch replacements (MAT 56S) that has been undisputed and admitted into the evidentiary record in several past GRCs. As further discussed in testimony, PG&E agreed under the 2020 GRC Settlement Agreement (Settlement Agreement) to replace 90 pre-1975 LBOR switches per year

for the 2020 GRC period. The CPUC approved the Settlement Agreement in Decision (D.) 20-12-005. Consequently, PG&E's LBOR switch replacement activities under MAT 56S are necessary to comply with a regulatory requirement. Historical information regarding the number of failed LBOR switches per year and a disaggregation of the types of failures observed is not relevant to PG&E's GRC forecast for LBOR switch replacements, and would be provide little evidentiary value. Subject to and without waiving this objection, PG&E responds as follows:

PG&E does not possess information tracking the annual number and type (high-energy versus other failure mode) of LBOR switch failures dating back to 2000, and the information would be exceedingly difficult and time consuming to reconstruct. However, the background testimony cited above provides general information that there were approximately 459 reports of a failed LBOR switches over an 18-year period. Thus, it is reasonable to assume that there were about 25 failures per year, based on a simple 18-year average. As noted above, some of these annual failures are high-energy, involving such things as an explosion, fire, enclosure damage, or smoke. However, the high-energy failure distinction is largely irrelevant, as any frequency of high-energy failures poses a safety risk that PG&E is required to address.

c. See response to subpart (b). In addition, PG&E does not possess information tracking "how many [switch failures] per year were associated with switches that were 'manufactured in the 1970s or 1980s.'"

d. See response to subpart (b). In addition, PG&E does not possess information tracking "how many [switch failures] per year were associated with switches that were manufactured prior to 1975."

e. See response to subpart (b). In addition, PG&E does not possess information tracking "how many of the failed LBOR oil switches between 2000 and 2021 were associated with pre-1975 switches without oil inspection sight glasses."

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PG&E Data Request No.:	TURN_024-Q04		
PG&E File Name:	GRC-2023-PhI_DR_TURN_024-Q04		
Request Date:	September 21, 2021	Requester DR No.:	TURN-PG&E-24
Date Sent:	October 5, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Hayley Goodson

SUBJECT: PG&E-4 (ELECTRIC DISTRIBUTION), CHAPTER 13 (ASSET MANAGEMENT & RELIABILITY)

QUESTION 04

Data Requests – PG&E-4, Chapter 13 (OH and UG Asset Management and Reliability)

Regarding LBOR switches manufactured prior to 1975:

a. Please reconcile the following two statements:
   - "LBOR switches manufactured prior to 1975 lack oil inspection sight glasses." (p. 13-39, lines 29-30)
   - "As of January 1, 2015, PG&E identified approximately 2,500 LBOR switches on the system manufactured prior to 1975. Of the approximately 2,500 pre-1975 switches identified, and field inspected, nearly one-third were found not to have oil sight glasses." (p. 13-40, fn. 41)

b. Did PG&E field inspect all 2,500 LBOR switches manufactured prior to 1975 that were identified on the system as of January 1, 2015?

c. Does PG&E treat LBOR switches manufactured prior to 1975 with oil inspection sight glasses and without oil inspection sight glasses the same in terms of priority for replacement under the MAT 56S program? Why or why not?

ANSWER 04

During our preparation of this data response, PG&E found an inadvertent error in our testimony/workpaper. PG&E's response below provides the correction, which will also be included in our next submission of errata to the service list.

a. The sentence on p. 13-39, lines 29-30, should begin with "A number of…". PG&E did not intend to imply that all LBOR switches manufactured prior to 1975 lack oil inspection sight glasses. The sentence as revised aligns with the second statement.

b. As part of UG inspection cycle, PG&E inspects all equipment every 3 years. In so doing, PG&E would have inspected all LBORs installed in 1975 and earlier, which would include LBOR switches manufactured prior to 1975.

c. PG&E does not treat LBOR switches manufactured prior to 1975 with or without oil inspection sight glasses differently. PG&E MAT 56S program targets the removal of all antiquated LBOR switches.

PACIFIC GAS AND ELECTRIC COMPANY
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Data Response

PG&E Data Request No.:	TURN_024-Q05		
PG&E File Name:	GRC-2023-PhI_DR_TURN_024-Q05		
Request Date:	September 21, 2021	Requester DR No.:	TURN-PG&E-24
Date Sent:	October 5, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Hayley Goodson

SUBJECT: PG&E-4 (ELECTRIC DISTRIBUTION), CHAPTER 13 (ASSET MANAGEMENT & RELIABILITY)

QUESTION 05

Data Requests – PG&E-4, Chapter 13 (OH and UG Asset Management and Reliability)

Re. p. 13-40 (lines 7-10), PG&E states, "The MAT 56S replacement program began in 2014 and has completed 243 units through 2020. This does not include replacements performed under other programs such as emergency, reliability, and maintenance."

Please identify the number of LBOR switches that existed in PG&E's system when the LBOR Switch Replacement program began in 2014 and at the end of each year, 2014-2020 and currently year-to-date in 2021, disaggregated by switches that were manufactured prior to 1975 and all other LBOR switches.

ANSWER 05

PG&E objects to this question on the grounds that the question asks for actual 2021 data while PG&E's 2023 GRC forecast uses a base year of 2020 recorded data in accordance with the Commission's Rate Case Plan. Notwithstanding the foregoing, and without waiving PG&E's right to object to the admissibility of the requested information into evidence, PG&E responds as follows:

PG&E will provide 2021 data in March 2022.

There are currently approximately 15,124 installed LBORs in PG&E's system. Of those, approximately 1,579 have an installation date of 1975 or earlier.

In 2020 PG&E replaced 51 LBORs under 56S. Of the 51 LBORs replaced in 2020, 48 were confirmed to have been manufactured pre-1975.

PG&E does not possess the count/population of LBORs remaining at the end of each year for the time period between 2014-2019. Back calculating of the LBOR population does not work either, since there are other programs that also replace LBORs.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_040-Q02		
PG&E File Name:	GRC-2023-PhI_DR_TURN_040-Q02		
Request Date:	October 11, 2021	Requester DR No.:	TURN-PG&E-40
Date Sent:	October 25, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Hayley Goodson

SUBJECT: PG&E-4 (ELECTRIC DISTRIBUTION), CHAPTER 11 (SURGE ARRESTERS, CERAMIC INSULATORS)

QUESTION 02

Please identify the number of surge arresters that PG&E replaced in each year, 2010-2020 during the course of routine or any other coordinated or opportunistic maintenance (i.e., by any program other than the Non-Exempt Surge Arrester Replacement program).

ANSWER 02

The number of surge arresters that PG&E replaced in each year from 2010 to 2020 during the course of routine or any other coordinated or opportunistic maintenance (i.e., by any program other than the Non-Exempt Surge Arrester Replacement program):

- 2010 – 245
- 2011 – 409
- 2012 – 450
- 2013 – 507
- 2014 – 396
- 2015 – 378
- 2016 – 373
- 2017 – 337
- 2018 – 274
- 2019 – 299
- 2020 – 175
- 2010 to 2020 total – 3,843

PACIFIC GAS AND ELECTRIC COMPANY
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PG&E Data Request No.:	TURN_040-Q04		
PG&E File Name:	GRC-2023-PhI_DR_TURN_040-Q04		
Request Date:	October 11, 2021	Requester DR No.:	TURN-PG&E-40
Date Sent:	October 25, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Paul McGregor (a-g) Mark Esguerra (h-i)	Requester:	Hayley Goodson

SUBJECT: PG&E-4 (ELECTRIC DISTRIBUTION), CHAPTER 11 (SURGE ARRESTERS, CERAMIC INSULATORS)

QUESTION 04

In Footnote 12 on p. 11-23 of the 2020 RAMP report, PG&E states,

> "Non-Exempt Surge Arrester Replacement is a mitigation for two RAMP risks—Wildfire and Failure of Electric Distribution Overhead Assets—because it will reduce both ignitions and equipment failure. The primary benefit of the mitigation is to reduce Wildfire risk. PG&E calculated the aggregated risk reduction score for both risks and divided that score by the total cost of the mitigation to calculate the overall RSE for the mitigation."

PG&E further states at p. 11-39 (lines 12-18) of the 2020 RAMP report,

> "Non-Exempt Surge Arrester Replacement accounts for 45 percent of 2023-2026 spending on mitigations that are primarily focused on the Failure of DOH Assets risk. The program, which will be completed in 2023, has a relatively low 2023-2026 RSE of 0.02, but PG&E believes the grounding portion of the work is mandatory in order to bring surge arrester installation into compliance with GO 95 and that the simultaneous replacement of surge arresters is prudent asset management."

Finally, PG&E sets forth in the 2023 GRC an RSE of 0.1 for Non-Exempt Surge Arrester Replacement done for both Wildfire Risk (p. 3-30 (Table 3-3, line 4) of Ex. PG&E-4 in the instant GRC) and the Failure of Distribution Overhead Asset Risk (p. 3-37 (Table 3-4, line 3) of Ex. PG&E-4 in the instant GRC), which is substantially larger than the 0.02 that PG&E identified in the 2020 RAMP report.

a. Please provide the magnitude of the total reduction to the risk score (i.e., *not* the RSE, but the change to the numerator of the RSE), disaggregated by each risk (i.e., (i) wildfire ignitions and (ii) equipment failure), associated with the RSEs of 0.02 (from the 2020 RAMP) and 0.1 (from the 2023 GRC).

b. Please further disaggregate the total risk reduction score (i.e., *not* the RSE, but the change to the numerator of the RSE) that PG&E identifies in Part a of this request by the amounts owing to (i) surge-arrester replacement and (ii) correction of abnormal grounding conditions.

c. Please identify the magnitude of total risk reduction score (i.e., *not* the RSE, but the change to the numerator of the RSE) owing to the Non-Exempt Surge Arrester Replacement program for each of (i) Wildfire Risk and (ii) Failure of Distribution Overhead Asset Risk.

d. Please clarify whether the RSE of 0.02 (from the 2020 RAMP Report) represents the aggregate RSE for the combined program of replacing non-exempt surge arresters and correcting the non-compliant grounding. If yes, please disaggregate and provide the RSE separately for i) surge-arrester replacements and ii) correction of abnormal grounding conditions. Please provide these values for both Wildfire Risk and Failure of Distribution Overhead Asset Risk.

e. If the 0.02 RSE (from the 2020 RAMP Report) does not include the risk reduction attributable to the correction of non-compliant grounding conditions, please explain why PG&E did not include the risk-reduction of non-compliant grounding conditions in the 2020 RAMP RSE calculation and provide the RSE for the grounding correction work, disaggregated between Wildfire Risk and Failure of Distribution Overhead Asset Risk.

f. Please clarify whether the RSE of 0.1 (from the 2023 GRC) represents the aggregate RSE for the combined program of replacing non-exempt surge arresters and correcting the non-compliant grounding. If yes, please disaggregate and provide the RSE separately for i) surge-arrester replacements and ii) the correction of abnormal grounding conditions. Please provide these values for both Wildfire Risk and Failure of Distribution Overhead Asset Risk.

g. If the 0.1 RSE (from the 2023 GRC) does not include the risk reduction attributable to the correction of non-compliant grounding conditions, please explain why PG&E did not include the risk-reduction of non-compliant grounding conditions in the 2023 GRC, RSE calculation and provide the RSE for the grounding correction work, disaggregated between Wildfire Risk and Failure of Distribution Overhead Asset Risk.

h. Does PG&E believe that the Non-Exempt Surge Arrester Replacement program is justified in the hypothetical absence of the grounding-correction work. Please provide justification for the response, whether “yes” or “no”.

i. If the response to subpart (h) of this question is different with respect to locations in the HFTDs and non-HFTD, please so state and clarify and explain the justification for both i) HFTD and ii) non-HFTD locations.

ANSWER 04

a. PG&E filed a RAMP Errata on July 17, 2020, which included correction of the risk reduction and RSEs for Non-Exempt Surge Arrester Replacement program. This corrected an RSE of 0.02 to 0.16. The table below is based on the corrected RSEs from RAMP errata. The reduction to the risk score disaggregated by each risk associated with the RSEs of 0.16 (from the 2020 RAMP Errata) and 0.1 (from the

2023 GRC) are shown below. PG&E assumes wildfire ignitions and equipment failure to be the same as Wildfire Risk and Failure of Distribution Overhead Asset Risk.

	RSE RAMP (2023-2026)	NPV Risk Score Reduction RAMP (2023-2026)[1]	RSE GRC – Oct. 1 Correction (2023-2026)	NPV Risk Score Reduction GRC – Oct. 1 Correction (2023-2026)[2]
Wildfire Risk	0.07	2.79	0.09 (was 0.1 in GRC filing, 6/30/21)	11.99
Failure of Distribution Overhead Asset Risk	0.09	3.46	0.05	7.25

b. PG&E cannot differentiate between the risk reduction due to surge-arrester replacement and correction of abnormal grounding conditions because the program is designed to do both - the replacement of surge arrestor and correction of grounding - at the same time. The effectiveness of the program in the modeling takes into account both activities simultaneously because of the combined activity in the program.

c. Please see response to subpart (a), the last column in the table has the risk reduction scores for (i) Wildfire Risk and (ii) Failure of Distribution Overhead Asset Risk.

d. The RSE of 0.16 from the 2020 RAMP Errata represents the aggregate RSE for the combined program of replacing non-exempt surge arresters and correcting the non-compliant grounding. PG&E cannot differentiate between the RSE due to surge-arrester replacement and correction of abnormal grounding conditions because the program is designed to do both at the same time. The effectiveness of the program in the modeling takes into account both activities simultaneously because of the combined activity in the program.

e. Please see response to subpart (d).

f. Yes, 0.14 represents the aggregate RSE for the combined program of replacing non-exempt surge arresters and correcting the non-compliant grounding. PG&E cannot differentiate between the RSE due to surge-arrester replacement and correction of abnormal grounding conditions because the program is designed to do both the at the same time. The effectiveness of the program in the modeling takes into account both activities simultaneously because of the combined activity in the program.

g. Please see response to subpart (f).

[1] Note that the NPV was done to 2020 using 7.1% discount rate in RAMP.

[2] Note that the NPV was done to 2021 using 7% discount rate in GRC.

h. Yes, PG&E believes that the Non-Exempt Surge Arrester Replacement program is justified in the hypothetical absence of the grounding correction work. Surge arresters reduce the risk of ignition in both HFTD and non-HFTD areas.

i. The response to part h is not different with respect to locations in the HFTDs and non-HFTD, as non-exempt surge arresters are used to reduce ignition risk in all areas regardless of whether they are HFTD or non-HFTD.

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PG&E Data Request No.:	TURN_040-Q05		
PG&E File Name:	GRC-2023-PhI_DR_TURN_040-Q05		
Request Date:	October 11, 2021	Requester DR No.:	TURN-PG&E-40
Date Sent:	October 25, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Hayley Goodson

SUBJECT: PG&E-4 (ELECTRIC DISTRIBUTION), CHAPTER 11 (SURGE ARRESTERS, CERAMIC INSULATORS)

QUESTION 05

Please provide a histogram that depicts the age distribution of the current surge arrester deployment in five-year age increments (i.e., the number of arresters aged 0-5, 6-10, etc.).

ANSWER 05

PG&E tracks surge arresters in the GIS system with data needed to support operations; the tracked data does not include age and thus PG&E does not have the data requested available. Replacements of surge arresters are based on when the arresters "come into service" which means that there is an event that causes it to come to ground or if degraded conditions are observed during inspections. Age has not been a factor in the replacement of surge arresters; however, the current surge arrester replacement program has now started to record the install date of each unit installed.

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PG&E Data Request No.:	TURN_040-Q06		
PG&E File Name:	GRC-2023-PhI_DR_TURN_040-Q06		
Request Date:	October 11, 2021	Requester DR No.:	TURN-PG&E-40
Date Sent:	October 25, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Hayley Goodson

SUBJECT: PG&E-4 (ELECTRIC DISTRIBUTION), CHAPTER 11 (SURGE ARRESTERS, CERAMIC INSULATORS)

QUESTION 06

Please provide a histogram that depicts the distribution of the age at which the arresters that have been replaced since 2010 were replaced in five-year age increments (i.e., the number of arresters replaced at age 0-5, 6-10, etc.).

ANSWER 06

PG&E tracks surge arresters in the GIS system with data needed to support operations; the tracked data does not include age and thus PG&E does not have the data requested available. Replacements of surge arresters are based on when the arresters "come into service" which means that there is an event that causes it to come to ground or if degraded conditions are observed during inspections. Age has not been a factor in the replacement of surge arresters; however, the current surge arrester replacement program has now started to record the install date of each unit installed.

1. PACIFIC GAS AND ELECTRIC COMPANY
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PG&E Data Request No.:	TURN_040-Q10		
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Request Date:	October 11, 2021	Requester DR No.:	TURN-PG&E-40
Date Sent:	November 1, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Hayley Goodson

SUBJECT: PG&E-4 (ELECTRIC DISTRIBUTION), CHAPTER 11 (SURGE ARRESTERS, CERAMIC INSULATORS)

QUESTION 10

Re. WP 11-43, Workpaper Table 11-39:

a. For each year included in the table, please separate the annual, recorded and forecasted cost and unit count by HFTD and non-HFTD replacements.

b. Please disaggregate the total cost for the Non-Exempt Surge Arrester Replacement program represented in the referenced table between the cost of the (i) surge arrester replacements and (ii) G.O.95-related, grounding compliance work.

c. Please identify the cost for the Non-Exempt Surge Arrester Replacement program, were PG&E to replace Non-Exempt Surge Arresters and correct G.O. 95-related grounding work separately (with no synergies between the program implementations assumed, similar to the way costs were disaggregated for separate programs in PG&E's response to TURN 10-9 in A.18-12-009, PG&E's 2020 GRC).

d. Please state PG&E's rationale for substantially reducing the replacement count in 2022 and 2023 (relative to 2021).

e. Please state PG&E's rationale for substantially augmenting the replacement count in 2024 (relative to 2023).

ANSWER 10

a. PG&E does not disaggregate cost based on HFTD classification. This data is not available. Work is planned based upon seeking efficient ways to execute – e.g. proximity of locations, availability of crew within a geography, etc. Recorded and forecast costs are listed on page WP 11-43, lines 12,14 15 and 17.

   The following table shows the unit split between HFTD and non-HFTD for recorded actuals for the years 2017 – 2020 and forecast units for the years 2021 - 2026. During the preparation of this data response, PG&E found an inadvertent

error in the 2018 completed units in the workpapers; the correct total is 12,857. This correction will be included in an upcoming submission of errata to the service list

Year	Non-HFTD (Units)	HFTD (Units)
2017 (Actuals)	619	0
2018 (Actuals)	8,402	4,455
2019 (Actuals)	0	4,602
2020 (Actuals)	4,099	10,263
2021 (Forecast)	0	20,837
2022 (Forecast)	3,841	0
2023 (Forecast)	3,913	0
2024 (Forecast)	3,848	0
2025 (Forecast)	7,360	0
2026 (Forecast)	7,237	0

b. PG&E does not disaggregate the forecast or recorded costs between Surge Arrester replacement and Grounding Compliance work. This data is not available.

c. Please see (b) above.

d. PG&E's GRC forecast prioritized surge arrester replacement work in HFTD locations ahead of non-HFTD locations; the forecast envisioned completing all HFTD locations in 2021. PG&E does now expect some carryover of HFTD locations into 2022. Locations planned for 2023 and beyond are all in non-HFTD locations; that work is prioritized with other non-HFTD maintenance work and will be done at a slower pace.

e. See answer to (d) above. PG&E expects more resources to be available for non-HFTD work in 2024, 2025 and 2026. The forecast reflects this assumption.

PACIFIC GAS AND ELECTRIC COMPANY
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Data Response

PG&E Data Request No.:	TURN_040-Q14		
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Request Date:	October 11, 2021	Requester DR No.:	TURN-PG&E-40
Date Sent:	October 25, 2021	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Hayley Goodson

SUBJECT: PG&E-4 (ELECTRIC DISTRIBUTION), CHAPTER 11 (SURGE ARRESTERS, CERAMIC INSULATORS)

QUESTION 14

Is PG&E aware of any structural fires that were the direct result of single-grounded transformer-surge arrester systems since November 4, 2015? If yes, please identify each structural fire by date and provide a brief description of the circumstances that PG&E believes caused the fire and qualification of the consequences of the fire.

ANSWER 14

PG&E is not aware of any structure fires resulting in ignition from surge arresters since November 4, 2015.

PACIFIC GAS AND ELECTRIC COMPANY
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Data Response

PG&E Data Request No.:	TURN_094-Q007		
PG&E File Name:	GRC-2023-PhI_DR_TURN_094-Q007		
Request Date:	January 20, 2022	Requester DR No.:	TURN-PG&E-094
Date Sent:	February 16, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Maria Ly	Requester:	Katy Morsony

SUBJECT: PG&E-4 (ELECTRIC DISTRIBUTION), CHAPTER 15

QUESTION 007

Data Requests – Substation Asset Management (PG&E-4, Chapter 15)

At p. 15-6:14-17, PG&E states, "PG&E is working towards guard rail replacement rates for transformers and circuit breaker replacements within the context of the Electric Operations (EO) prioritization framework." Please:

a. Define, "guard rail replacement rates."

b. Identify the guard-rail replacement rate for (i) transformers and (ii) circuit breakers.

c. Provide the analysis that PG&E executed to support the rates identified in subpart b, including but not limited to any Excel-formatted files with working cells and any assumptions identified and justified.

ANSWER 007

a. Guard rail replacement rates are the minimum number of replacements recommended to reach a steady state replacement rate for a specific asset fleet based on the Institute of Asset Management's (IAM) guard rail formula:

$$\frac{1}{x}(asset\ population) = steady\ state\ units/year$$

$$x = expected\ lifespan\ of\ the\ asset\ type$$

where the asset population for each asset type is defined by the available asset inventory and the expected lifespan for a given asset type refers to the average age of decommissioned assets and is based on the historic asset failure data.

b. The guard rail replacement rate at the time of the filing was (i) 30 transformers per year and (ii) 82 circuit breakers per year.

c. GRC-2023-PhI_DR_TURN_094-Q007Atch01 shows the analysis used to support the replacement rates identified in subpart b. The supporting detail in the spreadsheet was used as inputs for the circuit breaker and transformer guard rail calculations. The tabs contain: (1) the inventory of circuit breakers and transformers, (2) a list of circuit breaker and transformer ages at the time of failure for the select

years tracked, and (3) application of the IAM guard rail formula to the inventory and failure data.

(Note that the guard rail replacement rate shown in the spreadsheet differs slightly from the rate shown in part b because the current analysis includes 2021 data.)

Interrupting Medium	Breaker Population	Average Age of Failure (2017- EOY 2021)	Guard Rail Analysis	Assumptions
OIL	358	50.5	7.1	Air and SF6 breakers were excluded from the guard rail analysis because there have not been any AIR CB failures and only a single SF6 CB failure in the last five years. Additional the pupulation of AIR and SF6 breakers represents approximately 4% of the CB pupulation.
VAC	2,544	33.7	75.5	
Total Count	2,902		82.6	

Failure Year	Description	Age
2021	Stone Corral: Replace CB 1108	49
2021	Cottonwood: Replace CB 1101 and 1103	17
2021	Cottonwood: Replace CB 1101 and 1103	17
2021	Madison: Replace CB 1105/2	55
2021	Swift CB 2109	49
2021	Llagas:Replace CB 2103	49
2021	Placerville: Replace CB 2106	40
2021	Kanaka: Repl CB 1101	57
2021	Daly City: Replace 12kV CB1200/2	19
2021	ALTO: REPLACE CB 1124	50
2021	Zaca:Emerg repl CB 1102	47
2021	Figarden Sub:EM Repl 21kV 125VDC CB 2109	24
2021	DUNBAR: REPL CB 1103	46
2021	STELLING: EM Replace CB1103	10
2021	MCKEE: EM Replace CB1104	55
2021	CAMP EVERS: EM Rep 21KV CB2106	50
2021	MCCALL: REP EM CB 1500/2	46
2021	CHOLAME: EM REP CB 1101/2	35
2021	CUYAMA: EM CB 1104 FAILED	48
2021	TRIMBLE: EM REPL CB 1107	40
2021	Elk: EM REPL CB 1101	18
2021	MONTE RIO: REPLACE CB 1113	36
2020	Fort Bragg A: Repl CB1103	18
2020	Paso Robles: Replace CB 1108	21
2020	Woodland: Replace Circuit Breaker 1103/2	53
2020	Willows A: Replace CB1103	27
2020	Watsonville: Replace CB 414	22
2020	Belmont: Replace CB 1300	23
2020	Paul Sweet: Replace CB 2107	32
2020	Piercy: Replace CB 5	20
2020	Whisman: Replace CB 1109	24
2020	Panorama: Replace CB1102	32
2020	Britton: Replace CB 1300	38
2020	Silverado: Replace CB2105	31
2020	Belle Haven: Replace CB 1103	30
2020	Apple Hill: Replace CB 2102	39
2020	Orick: EM Replace CB 1102	26
2020	Paradise: EM CB 1104	22
2020	Jacobs Corner: CB 1101	29
2020	Stone Corral: CB 1110	47
2020	Temblor: CB 2103	35
2020	Figarden: CB 2200	23
2020	Kingsburg: CB 1116	58
2019	El Patio: Replace CB 1109	57
2019	Hillsdale: Replace CB 405	57
2019	Kingsburg: Replace CB 1300	18
2019	CMC: EM BRKR 1102 - FAILURE	19
2019	Emerald Lake: Repl CB 401 - WSIP	68
2019	Geyserville: Repl CB1101	42
2019	RIO BRAVO: EM CB 1106 REPL	55
2019	Anita: Repl **CB1101** and 1102	65
2019	Anita: Repl CB1101 and **1102**	65
2019	BULLARD: REPLACE CB 1102	55
2019	Chico B: Repl CB1102	55
2019	Belle Haven: Replace CB 404	60
2019	Monroe: Repl CB1106	33
2019	Bellevue: Repl CB1103	34
2019	Sisquoc: Repl CB 1102	33
2019	El Cerrito G: EF TIE/2 Breaker Repl.	15
2019	Vacaville: Replace CB 1107	57
2019	Salt Springs PH: Replace CB BK2-2	39
2019	Avena: Replace Breaker 1701	51
2019	San Leandro U: Replace CB 1110	59
2019	CLOVIS: EM REP CB 2110	34
2018	Arana: Replace CB 402	23

2018	Brentwood: Replace CB 2113	38
2018	Bucks Creek: Repl CB Bk4/2	30
2018	Camp Evers: Replace CB 2105	44
2018	Castroville: Replace **CB 2103** and 2104	38
2018	Castroville: Replace CB 2103 and **2104**	38
2018	Chico B: Replace CB1101	54
2018	Cortina: Replace CB 1101	38
2018	Cottle: Replace CB 1702	42
2018	Del Monte: Replace CB 2105	43
2018	Half Moon Bay: Replace CB 1102	49
2018	Hicks: Replace CB 1110	42
2018	Hicks: Replace CB 1116	42
2018	Hicks: Replace CB 2105	42
2018	Higgins: Replace CB1109, swiches and station service	26
2018	Industrial Acres: Replace CB 72	70
2018	Janes Creek: Replace CB1102	25
2018	McFarland: EM Replace CB 1105	6
2018	Meadow Lane: Replace CB 2104	45
2018	Mountain View: Replace CB 1109	53
2018	OCEANO: REP FAILED CB 1102	43
2018	Potter Valley: Replace CB4/2	39
2018	River Oaks: Replace CB 3 (2100/2)	20
2018	San Jose A: Replace CB 408	60
2018	Sneath Lane: Emer. Replacement of CB1107	53
2018	Swift: Replace CB 2200	40
2018	Taft: EM Rep CB1103	53
2018	Trimble: Replace CB 1104	35
2018	Trimble: Replace CB 1105	42
2018	EM WOODWARD REP CB 2200	n/a
2018	EM SAN LUIS OBISPO CB 1101	20
2017	Clayton: Replace CB 2211	41
2017	Ft. Bragg: REPLACE CB1104	15
2017	Lawrence: Replace CB 1110	48
2017	Deepwater Replace CB 1108	42
2017	Del Monte: Repair CB 2105	42
2017	Reservation Road: Replace CB 1102	47
2017	Rincon: Replace **CB1101** and CB1102	48
2017	Rincon: Replace CB1101 and **CB1102**	48
2017	Grays Flat: Replace Bank 1 Bushings CB401	77
2017	Bolinas: Replace Bank 1 Low Side Bushings	40
2017	Davis Replace CB 1108	50
2017	Mabury: Replace CB 1102	65
2017	Motague: Replace CB 2100	31
2017	Newburg: replace Recloser 1132	28
2017	Britton: Replace CB 1106	42
2017	Bay Meadows: Replace CB 2100	41
2017	Millbrae: Repalce Breaker 1102/2	47
2017	Maple Creek: Replace CB1102	40
2017	Fairview: Replace A-Phase CT on BK5/12 CB	44
2017	EM PASO ROBLES REP CB 1300	18
2016	Mt. Eden Sub: Replace CB 1100	41
2016	Rob Roy sub: Replace CB 2104	41
2016	Santa Rosa A: Replace CB1110	43
2016	Honcut Sub: Replace CB 1101	40
2016	Monterey: Replace CB 401/2	51
2016	San Luis Obispo: Replace CB 1102	18
2016	West Sacramento Sub: Replace CB 1111	42
2016	Montague Sub: Replace CB 2102	30
2016	Bay Meadows Sub: Replace CB 1105	51
2016	Malaga Sub: Replace CB 1108	49
2016	Vineyard Sub: Replace CBs **2104**, 2105, and 2106.	24
2016	Vineyard Sub: Replace CBs 2104, **2105**, and 2106.	25
2016	Vineyard Sub: Replace CBs 2104, 2105, and 2106.	26
2016	Tracy Sub: Replace Tracy CB1106	49
2016	Ashlan Sub: Emerg Repl CB 1100	45
2016	Dolan Road Sub: Replace CB 1101	22
2016	Del Monte Sub: Replace CB 2101	11
2016	Cottle Sub: Replace **CB 1703** & CB 1704	27
2016	Cottle Sub: Replace CB 1703 & **CB 1704**	17
2016	Redwood City Sub: Replace CB 406	64
2016	Woodland Sub: Repl CB 1105	49
2016	Tracy Sub: Replace CB 1103	42
2016	Pueblo Sub: Replace CB1104	45
2016	Greenbrae Sub: Replace CB1102	31
2016	East Marysville Sub: Replace CB1108	42
2016	Millbrae; Repalce CB402	14
2016	Lawrence Sub: Replace CB 1112	29
2016	Millbrae; Repalce CB404	62
2016	Madera Sub: Replace CB 1112	52

2016	Stockton A Sub: Replace CB 1104	44

PACIFIC GAS AND ELECTRIC COMPANY
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PG&E Data Request No.:	TURN_094-Q008		
PG&E File Name:	GRC-2023-PhI_DR_TURN_094-Q008		
Request Date:	January 20, 2022	Requester DR No.:	TURN-PG&E-094
Date Sent:	February 25, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Maria Ly	Requester:	Katy Morsony

SUBJECT: PG&E-4 (ELECTRIC DISTRIBUTION), CHAPTER 15

QUESTION 008

Data Requests – Substation Asset Management (PG&E-4, Chapter 15)

Re. p. 15-25:3-5, PG&E states, "Circuit breaker work has been prioritized in this GRC cycle because of the higher number of circuit breaker failures PG&E has been experiencing."

a. Please clarify whether the failure-count data that PG&E uses to support its assertion of a "higher number of circuit breaker failures PG&E has been experiencing" differs from the counts implied by the data in Workpaper EO-SBSTN-5_Reliability Consequence Information.xlsx (tab "distribution_outages_2015-2020"), which PG&E furnished in the revised risk-modeling workpapers in ED DR 1-1Supplemental 01. If yes, please provide the data that PG&E uses to support the referenced assertion.

b. Please disaggregate the annual failure counts that PG&E uses to support its assertion regarding higher numbers of circuit-breaker failures into the most granular failure mode that PG&E identifies (e.g., opened when it should not, failed in service (i.e., not opening or closing), failed while opening, etc.).

c. For each type of failure identified in subpart b of this request, please identify and explain the consequences of such failure type.

d. Please identify all ways PG&E becomes aware of a circuit breaker failure?

e. Did PG&E use the 2021 circuit-breaker failure rate to support, at least in part, its assertion that it is experiencing a "higher number of circuit breaker failures"? If yes, provide the number of 2021 failure (i) count and (ii) rate, as well as (iii) the date through which the data were collected.

f. Given the higher number of circuit-breaker failures that PG&E asserts, why has PG&E reduced the number of Circuit Breaker Overhauls to 5 in 2023 relative to the 2020 recorded count of 15 (per WP 15-20)?

ANSWER 008

a. Workpaper EO-SBSTN-5_Reliability Consequence Information.xlsx (tab "distribution_outages_2015-2020") only includes breaker failures resulting in

sustained outages, whereas the breaker failure trend is based on all just-in-time and in-service failures. The assertion that PG&E was experiencing a higher number of breaker failures was based the breaker failures in 2020 that totaled 32, which is more than the 2017-2019 three year average of 24 breaker failures.

b. PG&E manually tracks annual failure counts at the time the replacement is initiated for in-service and just-in-time failures. The totals do not align with the annual replacement rates discussed above because replacements are tracked at the time of installation, not the time of failure of the breaker being replaced. The table below provides information about failure modes to the extent it is available.

Failure Modes/ Year	**2016**	**2017**	**2018**	**2019**	**2020**
Animal Contact	1	-	2	1	1
Bushing	1	1	2	-	1
Component	5	4	6	3	1
Contact Erosion	-	-	-	-	-
Corrosion	-	-	3	-	1
CT	1	3	-	-	1
Insulation	-	-	-	-	1
Interrupter Failure	-	2	-	1	-
Lightning Strike	-	-	-	-	1
Mechanism	9	-	7	-	4
Oil	3	-	1	-	-
Oil Leak	-	1	2	5	1
Other	4	1	-	1	1
Overstressed	-	2	-	1	-
Unknown	3	3	4	7	2
Vacuum bottle	4	2	3	1	6
Water Intrusion	-	-	1	1	-
Total	**30**	**20**	**31**	**21**	**21**

c. All failure modes may lead to consequences such as unplanned outages, extended outages due to longer fault clearing times, and irreparable damage to the circuit breaker and adjacent equipment. A less likely consequence is catastrophic failure which could lead to serious injury or fatality of employees.

d. PG&E becomes aware of breaker failure through Operations and Substation Maintenance personnel who operate and perform maintenance activities such as field switching, inspections, mechanism services, breaker overhauls, testing and diagnostics.

e. No. PG&E did not use 2021 breaker failure rates to support its assertion that it has been experiencing a higher number of breaker failures as this information was not available at the time the forecast was made.

f. PG&E's 2023 forecast for Circuit Breaker Overhauls of 5 is less than the recorded count of 15 in 2020 because overhauls are generally triggered by SAP based on actual condition inputs such as Accumulated Critical Current (ACC) and oil test results. PG&E may exceed the 5 projected overhauls forecast for 2023 due to additional time-based and condition-triggered circuit breaker overhaul.

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PG&E Data Request No.:	TURN_120-Q005		
PG&E File Name:	GRC-2023-PhI_DR_TURN_120-Q005		
Request Date:	February 11, 2022	Requester DR No.:	TURN-PG&E-120
Date Sent:	February 28, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Katy Morsony

SUBJECT: PG&E-4 – CHAPTER 12 – POLE ASSET MANAGEMENT

QUESTION 005

Re. p. 12-28:13-15, PG&E states, "PG&E has had to hire additional contractors from outside the Company to execute the growing volume of pole replacements, which increases overall program costs."

a. Has PG&E done and/or will it do anything to reduce contractor and overtime costs for MAT 07D activities, relative to 2019 and 2020?

b. If the answer to Subpart a is yes:

   i. Please identify and explain the steps that PG&E has taken and/or plans to take in order to reduce contractor and overtime costs.

   ii. Please identify how, if at all, PG&E has included the efforts to reduce such costs in the 2023 unit-cost forecast.

   iii. If PG&E has not included the effects of such efforts in the 2023 forecast, why not?

c. If the answer to Subpart a is no, why does PG&E have no plans for reducing the need for contractor and overtime costs moving forward?

ANSWER 005

a. PG&E conducted a competitive Request for Proposal (RFP) with multiple vendors to establish cost competitive pricing for Distribution and Transmission Overhead and Underground work, which includes pole replacements in MWC 07. The RFP unitizes the work to encourage suppliers to manage their productivity. The RFP contracts were issued in April 2021 and resulted in significant savings in 2021, that PG&E anticipates will continue forward.

b. See response to part a above.

   i. See response to part a above.

   ii. Annual costs fluctuate from year to year, so PG&E uses the unbiased approach of utilizing the last three years of recorded costs (2018 – 2020) to

calculate the forecast basis. This three-year average forecast methodology includes all of the varying factors that have been transpiring during the past three years, allowing for more reasonable assumptions related to possible changes in cost, and volume, resulting in an unbiased forecast methodology.

iii. Not applicable.

c. Not applicable.

PACIFIC GAS AND ELECTRIC COMPANY
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PG&E Data Request No.:	TURN_120-Q007		
PG&E File Name:	GRC-2023-PhI_DR_TURN_120-Q007		
Request Date:	February 11, 2022	Requester DR No.:	TURN-PG&E-120
Date Sent:	February 28, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Katy Morsony

SUBJECT: PG&E-4 – CHAPTER 12 – POLE ASSET MANAGEMENT

QUESTION 007

Re. p. 12-28:1-15, PG&E states, "…PG&E has seen a significant increase in disposal costs of removed poles. The poles are treated wood and are considered hazardous material, which needs to be specially handled at the disposal sites. Pole replacement costs, both installation and disposal, have also increased due to stricter safety precautions, stricter permitting requirements, environmental requirements, and extraordinary traffic control. Lastly, PG&E has had to hire additional contractors from outside the Company to execute the growing volume of pole replacements, which increases overall program costs."

a. Has PG&E done and/or will it do anything to reduce contractor costs for MWC 07 activities, relative to 2019 and 2020?

b. If the answer to Subpart a is yes:

   i. Please identify and explain the steps that PG&E has taken and/or plans to take in order to reduce the contractor and/or overtime costs.

   ii. Please identify how, if at all, PG&E has included the efforts to reduce such costs in the 2023 unit-cost forecast.

   iii. If PG&E has not included the effects of such efforts in the 2023 forecast, why not?

c. If the answer to Subpart a is no, why does PG&E have no plans for reducing the need for contractor costs moving forward?

d. Please identify the recorded Dollars spent on pole-disposal in each year, 2016-2021.

e. Please identify the recorded Dollars spent on safety precautions in each of year, 2016-2021.

f. Please identify the recorded Dollars spent on permitting requirements in each of year, 2016-2021.

g. Please identify the recorded Dollars spent on traffic control in each of year, 2016-2021.

h. Please identify all legislative, regulatory, policy, and/or any other reasons that pole-disposal requirements have changed since 2016.

i. In what year did PG&E begin to see the referenced increase to pole disposal costs?

j. Please explain what PG&E means by "extraordinary traffic controls."

k. Please identify and explain each reason for the recent requirement for "extraordinary traffic controls."

ANSWER 007

a. See response to TURN_120-Q005.

b. See response to TURN_120-Q005.

c. See response to TURN_120-Q005.

d. See the table below for recorded dollars spent on pole-disposal in each year, 2016-2021.

	2016	2017	2018	2019	2020	2021
Pole Disposal	$ 71,907	$ 75,298	$ 56,188	$ 173,998	$ 166,570	$ 170,831

e. PG&E does not track dollars spent on safety precautions as a separate cost element. As requirements related to safety precautions change, the costs are associated with the overheads or cost element impacted by the safety precaution changes (e.g. pole-disposal, use of heavy equipment).

f. See the table below for recorded dollars spent on permitting requirements in each year, 2016-2021. Permitting costs vary annually, depending on the complexity of the locations and accessibility of pole replacements. In addition, permitting requirements increase with the use of heavy equipment (e.g. cranes, helicopters) to aid in work execution. In 2020, PG&E focused on pole replacements in High Fire Threat District (HFTD) areas, which are considered rural and have less permitting associated than urban areas.

	2016	2017	2018	2019	2020	2021
Permitting	$3,276,989	$2,557,270	$3,223,182	$2,584,583	$1,290,229	$2,523,892

g. See the table below for recorded dollars spent on traffic control in each year, 2016-2021. Traffic control costs vary annually, depending on the complexity of the locations and proximity to roadways. In addition, traffic control requirements increase in urban areas, where poles are located in close proximity to roadways. In 2020 and 2021, PG&E focused on pole reinforcements in HFTD areas, which are considered rural and have less traffic control requirements.

	2016	2017	2018	2019	2020	2021
Traffic Control	$2,196,047	$2,465,185	$5,014,029	$4,472,351	$2,186,162	$2,365,139

h. PG&E adheres to Assembly Bill No. 332 with respect to pole-disposal. No significant changes to Assembly Bill No. 332 have occurred since 2016.

i. Based on the dollars spent provided in part d above, PG&E saw a large increase in pole-disposal costs in 2019.

j. In recent years, PG&E has had to comply with additional traffic control requirements when replacing poles. For example, Caltrans has required site specific traffic control permits, no longer allowing PG&E's annual traffic control permits for some of the routine pole replacements. In addition, Caltrans has enacted a Design Standard Decision Document (DSDD) process, which has to be signed by a registered Civil Professional Engineer, that has significantly added to the requirements PG&E must comply with to replace poles.

k. See response to part j above.

PACIFIC GAS AND ELECTRIC COMPANY
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PG&E Data Request No.:	TURN_120-Q008		
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Date Sent:	February 28, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Katy Morsony

SUBJECT: PG&E-4 – CHAPTER 12 – POLE ASSET MANAGEMENT

QUESTION 008

Re. Unit Counts that PG&E sets forth on WP 12-20:

a. Please identify and explain each factor that generated the incremental unit count in 2018, relative to 2017 (i.e., 6,201).

b. Please disaggregate the unit counts forecasted for each year 2021-2023 into counts for poles located in (i) HFTD Tier 3 and Zone 1, (ii) HFTD Tier 2, and (iii) Non-HFTD (assumed to be Tier 1) areas.

c. Please identify the number of units replaced as the result of the clearance of Priority (i) A, (ii) B, and (iii) E EC Notifications in each year, 20162021, disaggregated into (i) Tier 3 and Zone 1 HFTD, (ii) Tier 2 HFTD, and (iii) non-HFTD areas.

ANSWER 008

a. PG&E was in an unprecedented situation in 2018. The October 2017 wildfires greatly impacted the entire company, shifting priorities and resources to the affected areas to provide crucial assistance. In addition, the CPUC issued Decision 17-12-024 (Fire Safety Rulemaking) and associated High Fire Threat District (HFTD) maps in early 2018. This rulemaking required that assets in Tier 3 and Tier 2 areas be remediated within 6 months and 12 months, respectively, of the inspection date, which accelerates PG&E's remediation timeframe. It also required that all poles identified for replacement in Tier 3 area be replaced prior to August 31, 2018, and all poles identified for replacement in Tier 2 areas be replaced by June 30, 2019. As a result of these changes, PG&E performed a considerable higher volume of pole replacements in 2018 than in 2017.

b. PG&E forecasts pole replacements in HFTD and non-HFTD areas. However, PG&E does not break out the forecasted pole replacements between HFTD Tiers. See the table below for pole replacement forecasts for 2021-2023.

	2021	**2022**	**2023**
HFTD	12,199	13,742	13,526
Non-HFTD	1,986	2,618	2,969
Total	**14,185**	**16,360**	**16,495**

c. The Pole Replacement Program does not perform Priority-A EC Notifications, as these are emergent conditions and performed in the Emergency Programs. Therefore, this response is limited to Priority-B and E EC Notifications.

In addition, HFTD areas were not established until 2018, so 2016 and 2017 cannot be disaggregated as requested. See the table below for details of pole replacements performed in 2016 and 2017.

	2016	**2017**
Priority-B	37	45
Priority-E	5,998	6,344
Total	**6,035**	**6,389**

See the table below for details of pole replacements performed in 2018, 2019 and 2020.

		2018	**2019**	**2020**
Priority-B	HFTD Tier 3 and Zone 1	17	489	803
	HFTD Tier 2	28	980	2,065
	Non-HFTD	83	294	1,440
	Total	**128**	**1,763**	**4,308**
Priority-E	HFTD Tier 3 and Zone 1	1,177	1,209	2,330
	HFTD Tier 2	2,294	4,029	2,254
	Non-HFTD	8,991	5,701	1,003
	Total	**12,462**	**10,939**	**5,587**
Priority-B and E	**Total**	**12,590**	**12,702**	**9,895**

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_124-Q003		
PG&E File Name:	GRC-2023-PhI_DR_TURN_124-Q003		
Request Date:	February 15, 2022	Requester DR No.:	TURN-PG&E-124
Date Sent:	March 2, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Katy Morsony

SUBJECT: PG&E-4, CHAPTER 10, OH AND UG ELECTRIC ASSET INSPECTIONS

QUESTION 003

Please provide versions of any documentation that contains each of the separate job aids that begin with TD-2305M-JA (for example, but not limited to TD-2305M-JA_05 "Corrosion Evaluation Job Aid" and TD-2305M-JA_07 "Crossarm Evaluation Job Aid", which are referenced at pp. 67 and 111, respectively, of Revision 8 of Job Aid: Overhead Inspection – TD-2305M-JA02) that was effective for (i) routine detailed inspections that occurred prior to the WSIP and (ii) enhanced detailed inspections that occurred during the WSIP. Please include the version of the Job Aid: Overhead Inspection (TD-2305M-JA02) that was effective prior to the version that was effective for the WSIP

ANSWER 003

Please see attachments below:

- TD-2305M- JA02, Rev. 5.7, April 2016: GRC-2023-PhI_DR_TURN_124-Q003Atch01
- TD-2305M- JA02, Rev. 5.8, 2/15/2019: GRC-2023-PhI_DR_TURN_124-Q003Atch02
- TD-2305M-JA02, Rev. 6.0, April 6, 2019: GRC-2023-PhI_DR_TURN_124-Q003Atch03
- TD-3322B-066-JA08 Effective: 05/24/2019, Rev: 1: GRC-2023-PhI_DR_TURN_124-Q003Atch04

Job Aid : Overhead Inspection

Summary

This job aid is designed to assist Compliance Inspectors in evaluating and prioritizing **abnormal conditions** on overhead facilities during GO 165 inspections. It is meant to provide guidance on issues that Inspectors may encounter **most frequently** during an inspection and **is not** intended to be an all-inclusive listing of **all** abnormal conditions or corrective actions

Target Audience

Qualified Electrical Workers (QEW) and all PS&R employees.

Before You Start

- Read the Safety section of the PS&R Manual.
- Wear appropriate personal protective equipment (PPE) for specific tasks and work area.

Forms You Need

FORMS	
Daily Log	Map Correction Form
OH EC Notification	Third-Party Utility Notification
Vegetation Form	Third-Party Non-Utility Notification
Idle Facility Form	Bird Incident Reporting
Minor Work Tracking Log	Pole Test Data Sheet

Tools You Need

- Map Package
- GPS
- Camera
- Inspection Tools

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Cellular Antennas

1. Broken/Damaged Cellular Antenna

General Guidance: If the broken antenna is creating a non-emergency safety or reliability issue, create a third party notification.

If the antenna is causing an emergency safety or reliability issue, contact your supervisor for instructions. Do not leave the location until it is made safe.

Minor Work: No

Related Documents: 027911

2. Cellular Antenna - Inadequate Clearance

General Guidance: Create a third party notification if a cellular antenna does not have adequate clearance from supply lines or equipment.

If the antenna is causing an emergency safety or reliability issue, contact your supervisor for instructions. Do not leave the location until it is made safe.

Minor Work: No

Related Documents: 027911, T&D Bulletin 2009-20

Climbing Space

1. Climbing Space - Obstructed

General Guidance: Evaluate pole to determine whether there is an obstruction caused by PG&E facilities or by third party facilities that is causing a compelling safety issue – based on the location of the pole and exposure to the worker - that needs to be addressed in 12 months.

Example: Equipment pole that cannot be accessed in a bucket truck.

Example where the climbing space **is not** a compelling condition: Equipment pole that is accessible 100% of the time in a bucket

For PG&E obstructions: Create an EC notification.

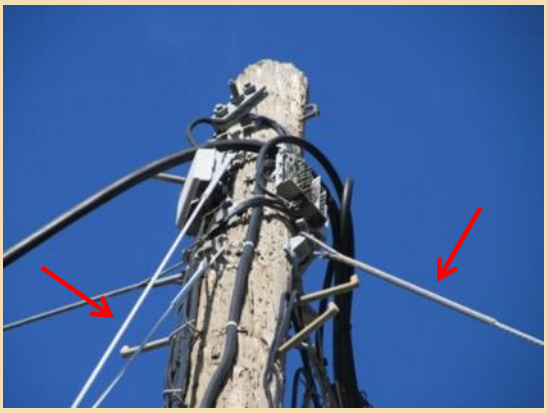
For third party obstructions: Create a third party notification if they pose a significant safety hazard.

If a third party obstruction is causing an emergency safety or reliability issue, contact your supervisor for instructions.

Minor Work: No

Related Documents: None

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COMMUNICATION IN CLIMBING SPACE	CLIMBING SPACE OBSTRUCTED
	
At this Location: Obstructed climbing space, access via bucket truck from street below. Also clearance issues between communications facilities and the PG&E down guys.	**At this Location:** Climbing space obstruction by communication facilities on pole with equipment. Communication messengers are too close. No bucket truck access.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third Party Notification: No	**Write Third Party Notification:** Yes
Write EC Form: No	**Write EC Form:** No

2. Climbing Space – Obstructed by Vegetation

General Guidance: For incidental vegetation in climbing space that can be moved when climbing, or quickly cleared prior to climbing, no action is required.

For major vegetation that cannot be quickly cleared or moved prior to climbing, evaluate the pole:

- Is there supply equipment on the pole that may need to be operated during emergency conditions?
- Should the obstruction be cleared for any other safety or reliability reason in the inspector's judgment?

If the answer is yes to any of these questions, the inspector will need to create an EC Notification to clear vegetation unless it can be addressed as minor work.

Minor Work: Yes

Related Documents: None

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OBSTRUCTED CLIMBING SPACE	CLIMBING SPACE OBSTRUCTED
	
At this Location: Obstructed climbing space. Inspector cannot see enough of the pole to complete Inspection (heavy vegetation, cannot see through) No equipment on pole. The only reason to address is to complete the inspection.	**At this Location:** Climbing space obstruction, able to perform inspection, no equipment on pole (able to see guys, able to see up the pole under tree)
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No, only need clearing to perform inspection	**Write Third Party:** No
Write EC Form: Yes • FDA=OH Facility / Limited Access/Obstruct / Inspect (Primary) • FDA=OH Facility / Limited Access/Obstruct / Remove • Priority ”B”, 0-3 months depending upon exposure; must complete before CPUC due date for map	**Write EC:** No, not compelling

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POLE WITH VEGETATION	IVY COVERED POLE
	
At this Location: 360° pole inspection not possible	**At this Location:** 360° pole inspection not possible
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA= OH Facility / Limited Access/Obstruct / Inspect (Primary) • FDA=OH Facility / Limited Access/Obstruct / Remove • Priority ”B”, 0-3 months depending upon exposure; must complete before CPUC due date for map	**Write EC Form:** Yes • FDA= OH Facility / Limited Access/Obstruct / Inspect (Primary) • FDA=OH Facility / Limited Access/Obstruct / Remove • Priority ”B”, 0-3 months depending upon exposure; must complete before CPUC due date for map

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Conductor

1. Conductor Broken/Damaged

General Guidance:

Visually check for damaged insulation (cracked, deteriorated) and damaged conductor (frayed, deteriorated wire). Also visually check for excessively corroded connectors.

Minor Work: Yes

- Repair damaged conductor as minor work if possible and if safe to do so.
- Fill out an EC Form to account for this **capital** minor work; charge time to your Division's standing order
    - FDA: Conductor / Damaged / Replace
    - Sign EC Form as completed
- IF not able to perform minor work, THEN write an EC Form.

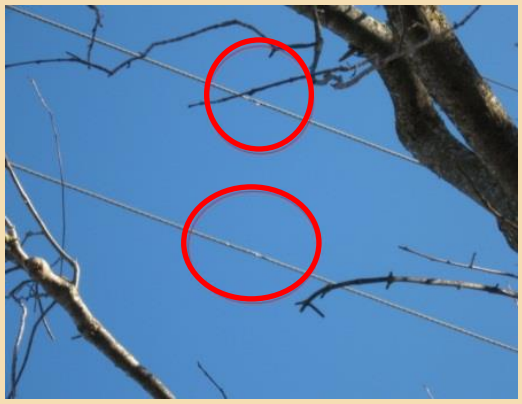
EC Form: Yes, if not able to perform minor work

- FDA: Conductor / Damaged / Replace
- Select the Priority and Due Date based the 'Probability & Impact Chart' and exposure risks

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BROKEN SERVICE NEUTRAL	DAMAGED/CRACKED GREY SERVICE
	
At this Location: Broken service neutral	**At this Location:** Cracked grey service
Perform Minor Work: Yes, if safe to do so. If you replace the service conductor, this is capital Minor Work. Fill out EC Form to account for this minor work; charge time to your Division standing order	**Perform Minor Work:** Yes, if safe to do so. If you replace the service conductor, this is capital Minor Work. Fill out EC Form to account for this minor work; charge time to your Division standing order
Write Third Party Notification: No	**Write Third Party Notification:** No
Write EC Form: Yes, if minor work is not possible, or to document completed capital minor work • FDA=Conductor / Broken/Damage / Repair or Replace • Priority “A”, follow Emergency Process	**Write EC Form:** Yes, if minor work is not possible, or to document completed capital minor work • FDA=Conductor / Broken / Replace - *OR* • FDA=Conductor / Damaged / Replace - *OR* • FDA=Conductor / Burnt / Replace • Priority ”B”, 0-3 months depending upon exposure

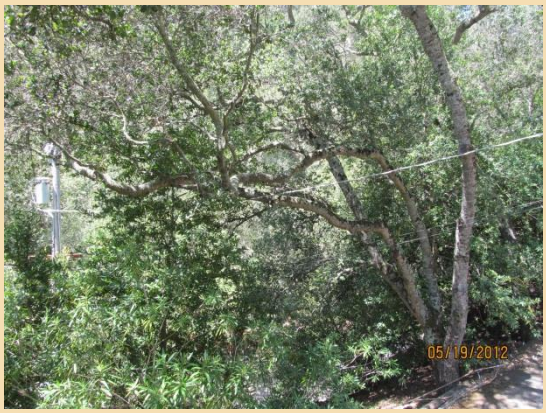
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DAMAGED SECONDARY	EXPOSED SERVICE CONNECTOR
	
At this Location: Damaged strands	**At this Location:** Exposed conductors
Perform Minor Work: No	**Perform Minor Work:** Yes, if safe to do so.
Write Third Party Notification: No	**Third-Party Notification:** No
Write EC Form: Yes • FDA= Conductor / Damage / Repair • Priority ”E”, 3-12 months depending upon exposure	**Write EC Form**: Yes, if minor work is not possible • FDA= Conductor / Broken/Damage / Repair • Priority ”E”, 3-12 months depending upon exposure

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CONDUCTOR TEARING APART	HARDWARE BROKEN
	
At this Location: Primary conductor damage (possibly shotgun)	**At this Location:** The #6 solid copper is broken causing strain on the conductor. Unsecured service.
Perform Minor Work: No	**Perform Minor Work:** Yes, if safe to do so
Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA= Conductor / Broken/Damage / Repair • Priority ”B”, 0-3 months depending upon exposure	**Write EC Form:** Yes, if minor work is not possible • FDA= Hardware/Framing / Broken/Damaged / Repair • Priority ”E”, 3-12 months depending upon exposure

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OVERHEAD SERVICE STRAIN ABRASION	OVERHEAD SERVICE STRAIN ABRASION
	
At this Location: Service strain abrasion, with possible burning at some sections. Damaged insulation.	**At this Location:** Service strain abrasion, no slack remaining
Perform Minor Work: Yes, if safe to do so. If you replace the service conductor, this is capital Minor Work. Fill out EC Form to account for this minor work; charge time to your Division standing order	**Perform Minor Work:** No
Write Third Party Notification: No	**Write Third Party Notification:** Yes
Write EC Form: Yes, if minor work is not possible, or to document completed capital minor work • FDA=Conductor / Broken/Damaged/ Repair or Replace • Priority ”E”, 3-12 months depending upon exposure, in comments add note about strain abrasion burnt conductor	**Write EC Form:** No

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2. Tie Wire Damaged

General Guidance:

Repair damaged secondary tie wire as minor work if possible.

Document damage to primary on an EC Form.

Minor Work: Yes, on secondary only

- Repair damage to secondary as minor work if possible and if safe to do so.
- IF not able to perform minor work, THEN write an EC Form.

EC Form: Yes, only if not able to perform minor work on secondary or primary damaged/broken

- FDA: Tie Wire/ Broken/Damaged / Repair or Replace
- Select the Priority and Due Date based the 'Probability & Impact Chart' and exposure risks

Related Documents: 022088

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3. Floaters

General Guidance: For Floaters create an EC Form if compelling, needs to be addressed in the next 12 months

Minor Work: No

Related Documents: 022088

FLOATER 4 KV



At this Location: Floater 4 KV, conductor is not contacting the arm. Rotten crossarm.

Perform Minor Work: No

Write Third Party Notification: No

Write EC Form: Yes

- FDA=Crossarm / Decayed/Rotten/ Replace
- Priority ”A”, follow Emergency Process
- Priority ”B”, 0-3 months depending upon exposure

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4. Broken or Unsecured Service Bob

General Guidance: Repair or Replace broken insulator, wires, pins, etc.

Minor Work: Yes

- Make repairs as minor work if possible and if safe to do so.
- IF not able to perform minor work, THEN write an EC Form.

EC Form: Yes

- FDA: Hardware / Broken/Damaged / Repair or Replace
- Select the Priority and Due Date based the 'Probability & Impact Chart' and exposure risks

Related Documents: None

5. Conductor Clearances (Refer to Clearance Job Aid in this Job Aid)

Cutouts / Fuses / Switches

1. Damaged Arcing Horns or Arc Quenchers

General Guidance: Call Restoration Dispatch to get a T-Man dispatched to the location to create a COE (CE) notification. Consider installing a warning tag on the pole. No EC should be created; write the location on map and Daily Log.

Minor Work: No

EC Form: No

Related Documents: 066195

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2. Damaged Bushing Mounted Cutout or Crossarm Mounted Cutout

General Guidance: IF hairline fractures / broken skirts are observed, THEN write an EC Form.

Minor Work: No

EC Form: Yes

- FDA: Cutout / Broken/Damaged / Replace
- Select the Priority and Due Date based the 'Probability & Impact Chart' and exposure risks

Related Documents: 056425

BROKEN DAMAGED CROSSARM MOUNTED CUTOUT	BROKEN INSULATOR ON AIR SWITCH
	
At this Location: Broken/Flashed cutout	**At this Location:** Broken insulator on air switch
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Cutout / Broken/Damaged / Replace • Priority "E", 3-12 months depending upon exposure • COE = No	**Write EC Form:** Yes • FDA=Cutout / Broken/Damaged / Replace • FDA Switch / Broken/Damaged / Replace • Priority "E", 3-12 months depending upon exposure • COE = Depending on voltage & Insulation value remaining if not operable

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3. Switch Handle/Control Box is not Locked

General Guidance: Ensure that boxes or enclosures located 8 feet or less above the ground are locked.

Minor Work: Yes

- Perform minor work if possible and if safe to do so.
- IF not able to perform minor work, THEN write an EC Form.

EC Form: Yes, only if not able to perform minor work

- FDA: Switch / Broken / Repair or Hardware / Missing / Install
- Select the Priority and Due Date based the 'Probability & Impact Chart' and exposure risks

Related Documents: 066195

Distribution Towers

General Guidance: Inspectors are required to inspect distribution towers for the following:

- Steel Covered by Earth
- Rust or Corrosion at Tower Footings
- Tower Footing Damaged
- Tower Member Loose
- Marking Hi-Sign Missing/Not Legible
- Guarding - Tower Not Guarded (Where Applicable)
- Guy Attachment, Turn Buckles, or Preformed Guys Loose
- Tower Rusty – Needs Paint

Minor Work: No

Related Documents: 022168, Utility Standard

Framing

1. Crossarm Broken/Deteriorated

General Guidance: Refer to TD-2305M-JA_07 "Crossarm Evaluation" Job Aid in this job aid

Minor Work: No

Related Documents: Crossarm Evaluation TD-2305M-JA_07, 015202, G12021

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2. Bridging Exists and Needs to be Repaired

General Guidance: Visual observation of broken / unattached bridge wire. Write an EC Form

Minor Work: No

Related Documents: 056845

BRIDGING	
	**At this Location:** Pole, burnt, pole failed **Perform Minor Work:** No **Write Third-Party Notification:** No **Write EC Form:** • FDA = Hardware/Framing / Broken/Damaged / Replace • Priority ”E”, 3-12 months depending upon exposure

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3. Underarm Bus Not Securely Attached

General Guidance:

It is a requirement to have at least two attachment points, secured to an underarm bus, one on each side.

It is a requirement to use the following corrosion resistant materials for attaching the underarm bus to the crossarm: straps, plumber's tape, lags, galvanized nails, staples, screws, bolts, zip ties, etc.

If an inspector finds an underarm bus secured with non-authorized material, such as duct tape, electrical tape, or rope, it must be secured by at least two additional approved attachment points.

When an inspector re-secures a bus, it must be brought up to construction standards; four attachment points using corrosion resistant materials.

Complete as minor work/re-secure the bus. IF it cannot be completed as minor work, then fill out EC if compelling and needs to be addressed within 12 months.

Minor Work: Yes

Related Documents: 021924, Crossarm Evaluation TD-2305M-JA_07

UNDER-ARM BUS LOOSE AND DETERIORATED



Side View



Front View

At this Location: UAB deteriorated, partial repair with rope, secured with one strap.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Under-Arm Bus / Broken/Damaged / Repair
- At minimum – must write up as Priority "F-R", next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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UNDER-ARM BUS LOOSE



At this Location: UAB Loose

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form:

- FDA=Under-Arm Bus / Broken/Damaged / Repair
  Priority ”E”, 3-12 months depending upon exposure

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4. Wood Pin Burnt/Tracking or Broken

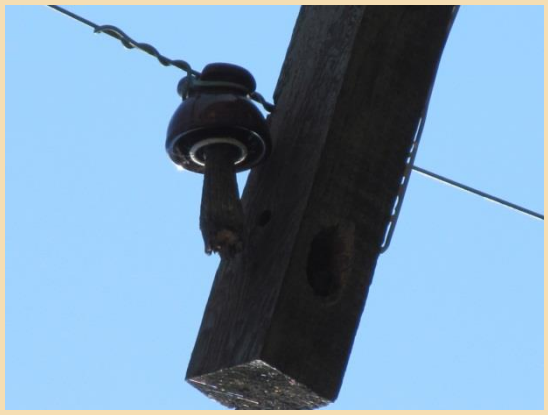
General Guidance:

Primary wood pins: If the primary wood pin is leaning or broken, or if there are signs of burning, or tracking, create a 0-3 month Priority “B” EC Form.

Secondary wood pins: Create an EC Form if compelling (needs to be addressed within 12 months).

Minor Work: No

Related Documents: 015202, G12021, TD-2305M-JA_07 Crossarm Evaluation

PIN BROKEN	PIN BROKEN
	
At this Location: Primary wood pin is broken and the conductor is laying on the crossarm	**At this Location:** Secondary wood pin is broken and the conductor is laying on the crossarm
Perform Minor Work: No	**Perform Minor Work:** Yes, replace wooden pin with steel pin.
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Hardware/Framing / Broken/Damage / Replace • Priority ”A”, follow Emergency Process	**Write EC Form:** Yes • FDA= Hardware/Framing / Broken/Damage / Replace • Priority ”E”, 3-12 months depending upon exposure OR • Priority ”A”, follow Emergency Process, depending on location, exposure, etc.

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PRIMARY WOOD PIN AT ANGLE	PRIMARY WOOD PIN SQUATTER
	
At this Location: Deteriorated primary wood pin at angle. Crossarm is acceptable.	**At this Location:** Primary wood pin squatter. Crossarm is acceptable. No armor rod with hand-tie.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Hardware/Framing / /Broken/Damaged / Replace • Priority ”E”, 3-12 months depending upon exposure	**Write EC Form:** Yes • FDA=Insulator / Primary Squatter/ Replace • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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Grounds / Ground Molding

1. Exposed Ground below 8'

General Guidance: Exposed grounds 8 feet or less from the ground must be covered. Inspectors must make every effort to cover the ground as minor work. If the exposed ground can be completed as minor work - preferred repair method is to use 1 1/2 inch plastic molding and not wood molding; if wood molding is used to make repair, use straps and not staples.

If it is not possible to cover the ground as minor work, create a minimum priority 'F' EC Form. Consider a higher priority based on how much of the ground is exposed, and on the amount of public exposure. The correct FDA is Ground/Exposed/Repair and not Molding Broken/damaged/ repair or replace.

Gaps in between molding segments should be covered if, in the inspector's judgment, they are large enough to allow human contact.

Minor Work: Yes

Related Documents: Utility Bulletin TD-2999B-023

EXPOSED GROUND	
	**At this Location:** Exposed grounds near sidewalk **Perform Minor Work:** Yes, at a minimum make safe **Write Third-Party Notification:** No **Write EC Form:** Only if not able to perform minor work • FDA=Ground / Exposed / Repair • At minimum – must write up as Priority "F-R", next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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REPAIR WITH 1.5” MOLDING



Before: Copper Wire sticking out from under the wood molding



After: 1.5 inch u-shaped molding installed over existing wood molding

At this Location: Wood molding with ground exposed

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: Only if not able to perform minor work

REPAIR WITH 2” PLASTIC



At this Location: Condition acceptable after repair of exposed ground

REPAIR WITH WOOD MOLDING



At this Location: Condition acceptable after repair with wood molding

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2. Exposed Ground above 8' to the Communication Level

General Guidance: If there are communication facilities on the pole, exposed grounds above 8 feet to the communication level must be covered. Cover the ground as minor work if possible. If not, create an EC Notification.

Gaps in between molding segments should be covered if, in the inspector's judgment, they are large enough to allow human contact.

If the pole is not a joint pole, no action required, because there is no exposure to the communication worker.

Minor Work: Yes

Related Documents: 021904, 036229

EXPOSED GROUND AT COMMUNICATION LEVEL	EXPOSED GROUND DUE TO TWISTED MOLDING
	
At this Location: Exposed ground at communications level. Wood molding broken in climbing space.	**At this Location:** Exposed ground in wood molding.
Perform Minor Work: Yes, if safe to do so.	**Perform Minor Work:** Yes, when safe to do so.
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Only if unable to perform minor work. • FDA=Ground / Exposed / Repair • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)	**Write EC Form:** Only if unable to perform minor work. • FDA=Ground / Exposed / Repair • FDA=Molding / Broken/Damaged / Repair • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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3. Ground Molding Unsecured/Loose

General Guidance: Ensure that the molding is in good condition and secured to the pole.

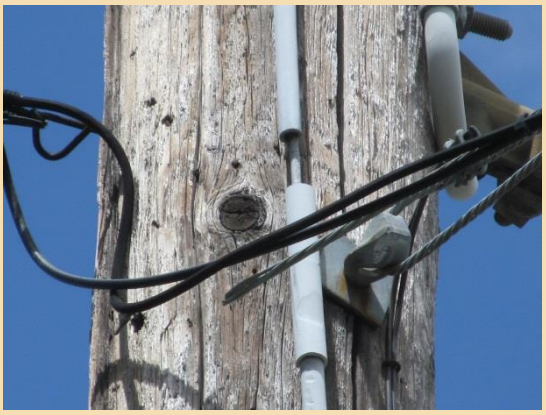
Look for unsecured and loose wood ground molding, unglued PVC ground molding joints, molding joints that have come apart exposing the ground wire, etc.

Gaps in between molding segments should be covered if, in the inspector's judgment, they are large enough to allow human contact.

When making repairs - must meet construction standards.

Minor Work: Yes

Related Documents: 02904

WOOD MOLDING NOT SECURE EXPOSING GROUND	PVC MOLDING NOT SECURE EXPOSING GROUND
	
At this Location: Wood molding not secure, allowing human contact.	**At this Location:** PVC molding not secure, due to failure of previous repairs, allowing human contact.
Perform Minor Work: Yes	**Perform Minor Work:** Yes
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Only if unable to perform minor work. • FDA=Ground / Exposed / Repair At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)	**Write EC Form:** Only if unable to perform minor work. • FDA=Ground / Exposed / Repair At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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PVC MOLDING SECURED	WOOD MOLDING SECURED
	
At this Location: PVC molding adequately secured with staples upon arrival. No action is required.	**At this Location:** Wood molding adequately secured with straps spacing 36 inches or less upon arrival. No action required.

4. Exposed Ground Rod

General Guidance: If the ground rod can be permanently covered as minor work, do so. If not, create an EC Form.

Minor Work: Yes

Related Documents: None

EXPOSED GROUND ROD	
	**At this Location:** Exposed ground rod **Perform Minor Work:** Yes **Write Third-Party Notification:** No **Write EC Form:** At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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5. Broken Ground

General Guidance: Inspector identifies a broken ground; refer to bulletin TD-2999B-023 for specific guidance about testing/replacing grounds

Minor Work: Yes

- Perform minor work if possible and if safe to do so.
- IF not able to perform minor work, THEN write an EC Form.

Related Documents: Utility Bulletin TD-2999B-023

Guys / Anchors

1. Down Guy Preform Buried

General Guidance:

Top of anchor head must be above grade. Expose anchor as minor work. Evaluate the unburied anchor guy pre-forms and visually inspect them.

Perform minor work to add extension or grade around anchor so the anchor head becomes visible, then no EC is required.

If the pre-form cannot be unburied as minor work, create an EC notification.

Notes:

- If you cannot dig up the anchor, and create an EC with a photo of a buried anchor **only** - the Gatekeeper will **not know** if the anchor can be replaced or if an extension can be installed; you should make every effort to dig up the anchor to perform a complete assessment. If your photo is of a buried anchor only, the general rule of thumb is that the EC will be created to **replace** the anchor.
- If you **cannot** dig up the anchor, but you can see most of the pre-form - an extension can *usually* be added (only one extension can be installed)

Minor Work: Yes

- Perform minor work if possible and if safe to do so.
- IF not able to perform minor work, THEN write an EC Form.

Related Documents: 022221

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BURIED ANCHOR



Before: Vegetation covers anchor



After: Vegetation cleared from anchor

At this Location: Anchor below grade overgrown with vegetation. After minor work inspector decides if the anchor can be adjusted or needs replaced.

Perform Minor Work: Yes, remove the vegetation
Yes, expose anchor and evaluate condition/corrosion
Yes, preferred method is to adjust anchor by adding extension

---

Write Third-Party Notification: No

Write EC Form: If cannot be addressed as minor work

- FDA=Anchor / Soil/Eroded/Graded / Replace (if the anchor cannot be adjusted)
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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ANCHOR EXTENSION



Anchor extension



Close-up

At this Location: Inspector performed minor work, exposed anchor, evaluated anchor to be in good condition so that extension could be installed, then installed extension. (Back fill not shown)

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: No

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ANCHOR COVERED BY CONCRETE



Anchor covered by concrete



Close-

At this Location: Anchor covered by concrete

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

FDA=Anchor / Soil/Eroded/Graded / Replace

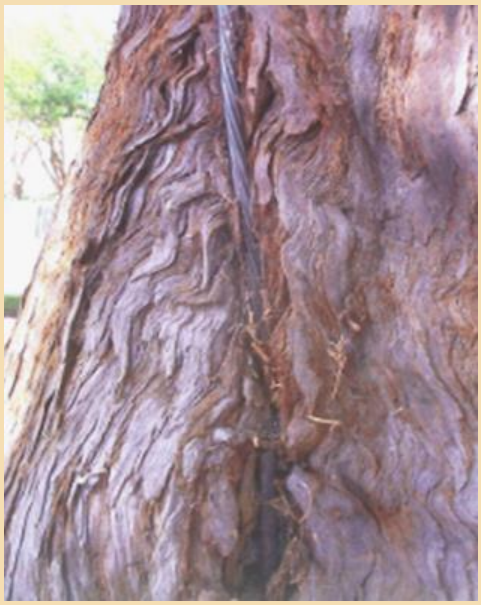
At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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ANCHOR BURIED BY VEGETATION



Anchor buried by roots



Anchor buried by tree

At this Location: Anchor buried by ivy roots / tree

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Anchor / Soil/Eroded/Graded / Replace
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

2. Visible Portion of Anchor Rod has Significant Corrosion

General Guidance: IF the anchor rod is significantly corroded, THEN create an EC Form.

Minor Work: No

EC Form: Yes, only if not able to perform minor work

- FDA: Anchor Corroded Replace
- Select the Priority and Due Date based the ‘Probability & Impact Chart’ and exposure risks

Related Documents: 025998

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ANCHOR ROD WITH SIGNIFICANT CORROSION



Anchor above ground



Below

At this Location: Corroded Anchor

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Anchor / Corroded / Replace
- Priority ”E”, 3-12 months depending upon exposure

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3. Guy Broken/Slack

General Guidance: Guys must be taut (straight, no belly). Tighten the guy as minor work if possible. If not possible, create an EC Notification.

If tightening the guy would exacerbate any pre-existing conditions on a facility (e.g. increase the lean of an already leaning pole, deform an already deforming pole), create an EC Notification with comments describing the situation.

Minor Work: Yes

Write EC: As needed based on field condition, severity of condition, and exposure

Related Documents: 022178

11.1 Guy Clearance

GUY CLEARANCE	GUY DAMAGED REPAIR
	
At this Location: Acceptable solution through plastic barrier. GO 95 requires 3” of radial clearance. Plastic barriers can be installed if less than 3” of clearance.	**At this Location:** Guy tail extends beyond the preform **near sidewalk**, safety hazard. **Perform Minor Work:** Yes **Write Third-Party Notification:** No **Write EC Form:** Only if minor work cannot be performed. • FDA Guy / Broken/Damaged/ Repair • Priority ”E”, 3-12 months depending upon exposure

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OVERGROWN GUY	TREE GROWING AROUND GUY
	
At this Location: Extensive dead ivy covering half of length of guy.	**At this Location:** Tree growing around guy
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Guy / Broken/Damaged / Replace • Priority ”E”, 3-12 months depending upon exposure	**Write EC Form:** Yes • FDA=Guy / Broken/Damaged / Replace • Priority ”E”, 3-12 months depending upon exposure – **OR -** • FDA=Guy / Overgrown / Trim • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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SLACK GUY



At this Location: Loose guy on left side

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: Yes, only if minor work is not possible

- FDA=Guy / Loose / Adjust
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

GUY GROUNDED BY VEGETATION



Guy grounded by vegetation



Guy grounded by vegetation



Guy overgrown by vegetation

At this Location: Guy grounded by vegetation, above the bob.

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: Yes, only if minor work cannot be performed

- FDA=Guy / Overgrown / Trim
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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IVY ON GUY AND PRIMARY



At this Location: Ivy on guy and on primary. Safety issues, possible energized guy and pole, transformer weeping – no oil on ground, evaluate per oil spill matrix.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Transformer / Leaks/Seeps/Weeps / Replace (primary)
- FDA=Guy / Overgrown / Trim
- Priority ”B”, 3 months or less depending upon exposure

TREE LIMB GROWING AROUND GUY



Guy through tree



Close-up

At this Location: Tree limb growing around guy, below the bob.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Guy / Strain/Abrasion / Remove
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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4. Guy Insulator Broken/Missing

General Guidance: Guys in the cylinder of “proximity” to conductors less than 35kV:

- 8 ft. or less above or below the conductor level
- 6 ft. or less horizontally from the surface of the pole

Must be sectionalized and ungrounded. Ensure there is an intact guy insulator.

Minor Work: No

EC Form: Yes

- FDA: Guy / Broken/Damaged / Replace or Guy / Missing / Install
- Select the Priority and Due Date based the ‘Probability & Impact Chart’ and exposure risks

Related Documents: 022178

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5. Down Guy Grounded above Guy Insulator (vegetation or other)

General Guidance: Ensure that all guys are not grounded above the guy insulator. Remove any foreign objects (e.g. vegetation) contacting and grounding the guy above the insulator as minor work. Clear so that new growth will not contact or ground the guy. (Rule of thumb is that growth per year is 1 foot, so trim back 5 feet.)

Minor Work: Yes

Related Documents: 022178

DOWN GUY GROUNDED ABOVE GUY INSULATOR	DOWN GUY GROUNDED ABOVE GUY INSULATOR CAUSING STRAIN AND ABRASION
	
At this Location: Vine growing up and across the guy insulator grounding the guy.	**At this Location:** Tree grounding the guy above the guy insulator causing strain and abrasion.
Perform Minor Work: Yes	**Perform Minor Work:** Yes, if minor work not possible
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes, only if minor work cannot be performed • FDA=Tree/Vine / Overgrown / Remove • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)	**Write EC Form:** Yes, only if minor work cannot be performed • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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6. Down Guy Marker Missing/Damaged

General Guidance: For poles installed **after 1996,** Guy Markers are required on **all** down guys. The markers must be a minimum 8 ft. in length. For poles installed ***prior to 1996,*** guy markers are **only required** on poles which are exposed to traffic. **Inspector should confirm the age of the pole via the date nail to verify the requirement.**

Install a single guy marker on multiple guys which are clamped together. For guys that are not clamped together, but on the same anchor, consider separate guy markers on each guy if the separation is large.

Note: Installing yellow colored guy marker does not negate the need to install visibility strips on the markers. Install visibility strips around traffic areas, on state highways, near curbs, driveways, etc. See visibility strip entry for more details.

Note: Install a segment of guy marker above cattle guards to ensure a minimum 8 ft. of guarding.

Minor Work: Yes

Related Documents: 06542, 022178, 99-34

GUY MARKER MISSING	CATTLE GUARD LESS THAN 8 FT
	
At this Location: Guy marker missing	**At this Location:** Cattle guard is less than 8 feet in length
Perform Minor Work: Yes, install new guy marker	**Perform Minor Work:** Yes, lower cattle guard and add guy marker to meet 8 feet requirement.
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: No, perform minor work	**Write EC Form:** No, perform minor work

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DOWN GUY: MARKER NOT REQUIRED	
	
At this Location: Acceptable down guy attached to building, no marker required.	**At this Location:** Acceptable down guy in marsh, no marker required.

Idle Facilities

1. Identifying and Documenting Idle Facilities

PS&R inspectors continue to identify and document idle lines as they would for any other field condition found, per the requirements and procedures in the Electric Distribution Preventative Maintenance (EDPM) Manual.

If idle lines are documented on hard copies (paper) rather than with PS&R mobile devices, PS&R inspectors update the Daily Log as follows:

- Create a new numbered entry.
- Write “IF” in the “Notification Type” column
- Include any applicable notes in the “Note” column.
- Create one IF Notification (TD-2459S-F01) for each section of idle line.

  Example: If there is an idle line with five poles, only one IF Notification is required for the entire section of line. ***Do not create an IF Notification for each pole.***

At a **minimum**, attach the following two attachments to each IF Notification:

- Photo of the field condition
- Map with the idle area clearly identified

Do not initiate an IF Notification or an EC Notification when **attachments to poles** (cross-arms, miscellaneous hardware, brackets, insulators, etc.) do not pose a safety or reliability risk to an idle facility.

Continue to document safety or reliability issues that meet criteria for vegetation notifications.

NOTE: Vegetation management personnel **do not** patrol or maintain vegetation on de-energized tap lines.

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Identify specific field conditions on Page 1 of the IF Notification. (The PS&R supervisor refers to these field conditions to prioritize the IF Notification.)

- The service planning due date (SPDD) on the IF Notification is specific to the investigation only and is the date that the investigation must be completed.
- For a list of field conditions and related QCR actions, refer to Table 1, "IF Field Conditions and Investigations Priorities," below.

NOTE: QCRs use IF Notifications to document potentially idle facilities. Customer service delivery (CSD) personnel use IF Notifications to investigate, classify, and document idle facility investigation results.

Table 1. IF Field Conditions and Investigation Priorities

Condition	Action	Investigation Priority
Safety Situation/Risk	• Mitigate hazard and make safe, which may include de-energizing. • Initiate an IF Notification for investigation. • Initiate an Electric Corrective (EC) Notification to document any other abnormal conditions to resolve.	**High** Submit to supervisor by end of day. Enter in SAP, and communicate to service planning personnel within 2 business days.
Idle transformers that do not have a blue sticker indicating a polychlorinated biphenyl (PCB) content of less that 5 parts per million (ppm) may be classified as High, Medium, or Low priority. Consider current field conditions, the transformer condition, and if the following sensitive locations are nearby: • Surface or ground waters • Sewers or sewage treatment systems • Private or public drinking water sources or distribution systems • Grazing lands • Vegetable gardens or agricultural areas • Daycare centers and schools	• If High priority, mitigate hazard and make safe, which may include de-energizing. • Initiate an IF Notification for investigation; priority is dependent upon field and equipment conditions. • Note the specific field conditions, transformer condition, and transform locations (see "Condition" column notes) in the Comments section.	**High – Medium-Low** To designate as High priority, consider the identified idle transformer locations, current condition of the transformer (see "Condition" column notes), and current condition of associated facilities (pole, crossarm, etc.)
Future work required to maintain existing idle facility (EC Notifications to repair/replace/relocate facilities).	• Initiate an IF Notification for investigation. • The IF priority depends on the due date of the EC.	**High – Medium-Low**
PG&E and Modesto Irrigation District (MID) service areas.	• Initiate an IF Notification for investigation.	**Medium**
Idle facilities in raptor concentration zones (RCZs) with suitable habitat to support threatened or endangered raptors.	• Initiate an IF Notification for investigation. • Initiate a Priority E, 3-month EC Notification to de-energize the facility.	**Medium – Low**
Oil-filled equipment considerations: • Surface or ground waters • Sewers or sewage treatment systems • Private or public drinking water sources or distribution systems • Grazing lands • Vegetable gardens or agricultural areas • Daycare centers and schools	• Initiate an IF Notification for investigation. • For idle transformers, note the absense or presence of a blue sticker on the IF Notification. • A blue sticker indicates a PCB content of less than 5 ppm.	**Medium**
Potential use for agricultural pumps or vacant buildings.	• Initiage an IF Notification for investigation.	**Low**
Entire primary tap is identificed as idle and is unfused. No future work is required to maintain the existing idle facility.	• Initiate an IF Nofication for investigation. • Initiate a Prioirty E, 3-month EC Notification to de-energize the line.	**Low**

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Identify idle facilities in RCZs.

Determine whether there is any potential use for agricultural pumps and/or vacant buildings.

Classify facilities that are to remain in the field as follows:

- De-Energized – Temporary Out of Service (TOS):
- Potential agricultural pump – TOS-AG
- Vacant building use – TOS-V

Energized – Temporary Idle Facility (TIF):

- Potential agricultural pump – TIF-AG
- Vacant building use – TIF-V

The following Table 2 is a complete listing of TOS/TIF classifications.

Table 2. TOS/TIF Classifications

Temporary Out of Service (TOS) De-Energized Temporary Idle Facility (TIF) Energized		
Facilities with a future use are grouped into one of the following classifications:		
TOS-AG	Potential agricultural use	De-energized
TIF-AG	Potential agricultural use	Energized
TOS-V	Potential service to an existing vacant building	De-energized
TIF-V	Potential service to an existing vacant building	Energized
TOS-CAP	Potential PG&E use for capacity or reliability	De-energized
TIF-CAP	Potential PG&E use for capacity or reliability	Energized
TOS-F	Future customer use identified by service planning	De-energized
TIF-F	Future customer use identified by service planning	Energized
TOS-MLX	Current Main Line Extension Agreement	De-energized
TIF-MLX	Current Main Line Extension Agreement	Energized
TOS-SFA	Current Special Facilities Agreement	De-energized
TIF-SFA	Current Special Facilities Agreement	Energized

When pending maintenance is identified on idle facilities, write a minimum of two notifications:

- One IF Notification (TD-2459S-F01) for the entire idle line
- One EC Notification per location requiring maintenance

After identifying pending maintenance on idle facilities, ensure that the IF Notification has the Field Condition box, "Future work required to maintain existing idle facility," checked. See Figure 1 below.

- Enter the following note in the EC Notification comments section: "IDLE notification created."
- Enter a note in both IF Notification and EC Notification comments with corresponding notification numbers, when available.

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Figure 1

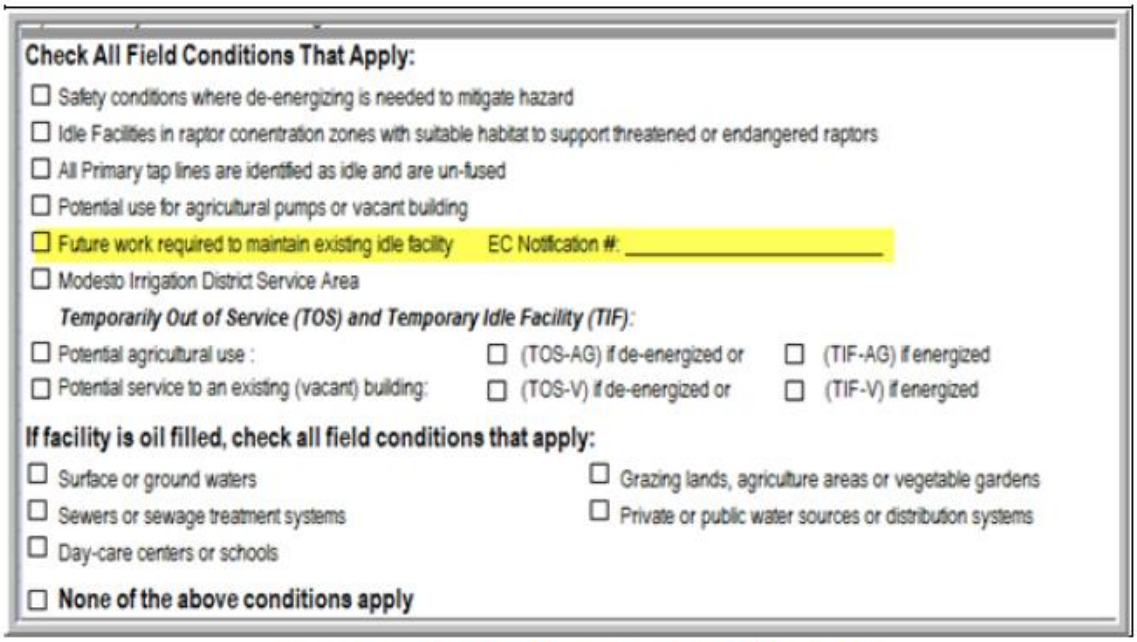


Figure 1. IF Notification – Future Work Required Field Condition and EC Notification Number

2. Energized Electric Line Facility No Longer Used to Serve Customer Load

General Guidance: It may be necessary to de-energize the idle facility:

If primary lines are energized, de-energize line sections by opening cut-outs. In raptor concentration zones (RCZs) or if the primary tap line is unfused, create a Priority E, 3-month Electric Corrective (EC) Notification to de-energize the jumpers.

NOTE
When idle transformers or sections of line de-energized by cut-outs are located in non-raptor areas, an EC Notification is **not** required to de-energize the jumpers.

Do not initiate an IF Notification or an EC Notification when attachments to poles (cross-arms, miscellaneous hardware, brackets, insulators, etc.) do not pose a safety or reliability risk to an idle facility. If it is not necessary to de-energize the idle facility, create a Priority “F” EC Notification.

Continue to document safety or reliability issues that meet criteria for vegetation notifications.

Minor Work: No

EC Form: Yes, to de-energize

- FDA: OH Facility Idle De-Energize
- Select the Priority “E”
- Select the 0-3 month Due Date

Idle Facility Form: Yes

Related Documents: TD-2459P-01

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3. De-Energized Electric Line Facility Already Identified on a Pending EC Notification but Not Mapped

General Guidance: Create a map change request if the facility is not mapped as idle.

Minor Work: No

Map Correction: Yes

Related Documents: TD-2459P-01

Insulators

1. Arcing or Tracking on Insulators

General Guidance: If there is evidence of arcing or tracking on a primary insulator, call the M&C supervisor, create Emergency tag, and follow emergency EC processes.

Minor Work: No

EC Form: Yes, create an Emergency EC Notification

Related Documents: Utility S2405

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2. Damaged Insulators

General Guidance:

IF a broken secondary insulator is compelling, THEN create an EC Form

Minor Work: No

EC Form: Yes

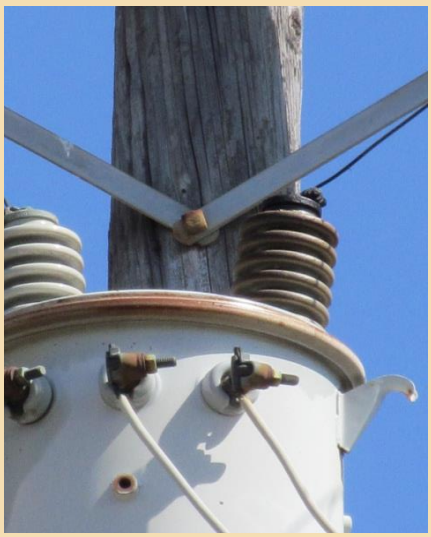
- FDA: Insulator Broken Replace
- Select the Priority and Due Date based the 'Probability & Impact Chart' and exposure risks

Related Documents: 022088, TD-2305M-JA_07 Crossarm Evaluation job aid

DAMAGED INSULATOR	INSULATOR LAYING ON ITS SIDE / PRIMARY ON THE ARM
	
At this Location: Damaged insulator	**At this Location:** Insulator lying on its side. Primary on the arm.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Insulator / Broken/ Damage / Replace • Priority "E", 3-12 months depending upon exposure	**Write EC Form:** Yes • FDA=Insulator / Broken/ Damage/ Replace • Priority "A", follow Emergency Process

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FLASHED INSULATOR ON TRANSFORMER



At this Location: Flashed image on transformer

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA= Transformer / Flashed / Replace
- Priority ”E”, 3-12 months depending upon exposure

BROKEN WOOD PIN ON PRIMARY



At this Location: Broken wood pin. Primary (High Voltage Sign). Conductor on arm.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Insulator / Squatter-(Primary) / Replace
- Priority ”A”, follow Emergency Process, (Conductor contacting crossarm)

FLASHED INSULATOR POTHEAD



At this Location: Flashed pothead

Perform Minor Work: No

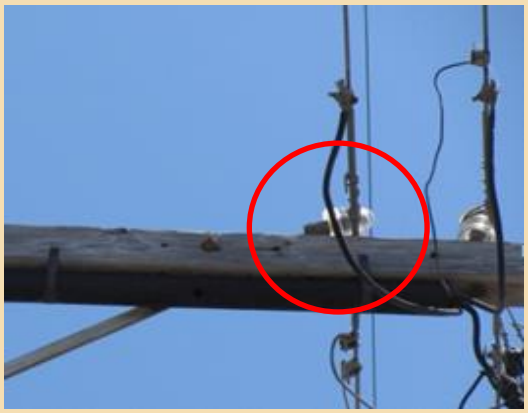
Write Third-Party Notification: No

Write EC Form: Yes or COE (pin or energized)

- FDA=Riser/Pothead / Flashed / Replace
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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BROKEN WOOD PIN ON SECONDARY



At this Location: Broken secondary wood pin. Conductor lying on the arm, tangent pole. (excluding urban wildfire areas, use risk priority matrix)

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: Yes, if minor work not possible

- FDA= Insulator / Squatter (Secondary) / Replace
- Priority ”B”, 0-3 months depending upon exposure

BROKEN SECONDARY INSULATOR



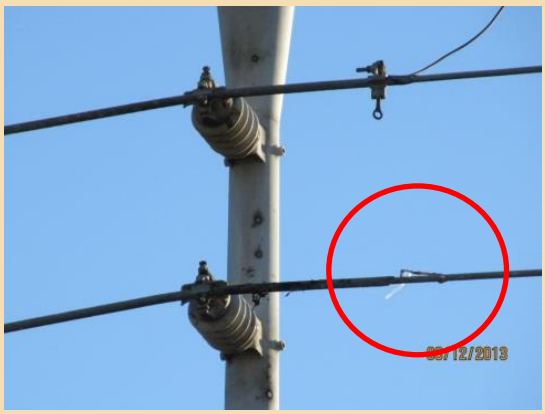
At this Location: Broken secondary insulator, double crossarm that has acceptable secondary insulator

Perform Minor Work: Yes, replace secondary insulator

Write Third-Party Notification: No

Write EC Form: No

FLASHED INSULATOR MYLAR BALLOON



At this Location: Flashed insulator by Mylar balloon

Perform Minor Work: No

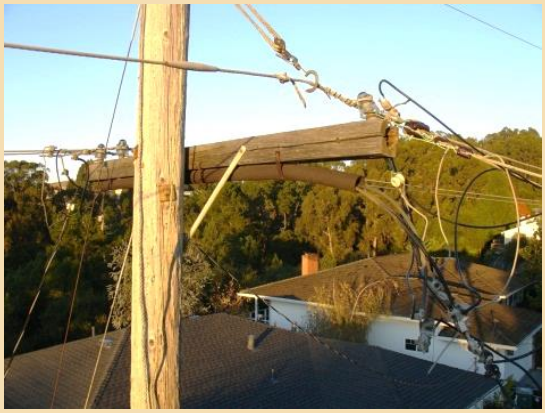
Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Insulator / Flashed / Replace
- Priority ”E”, 3-12 months depending upon exposure

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ACCEPTABLE TEMPORARY REPAIRS



Deteriorated Crossarm



Close-up

At this Location: Acceptable temporary repairs made by Troubleman. Crossarm deteriorated, temporary repair to stabilize secondary conductor. Pending EC Notification.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Crossarm / Broken/Damaged / Replace
- Priority ”E”, 3-12 months depending upon exposure

3. Squatters

General Guidance: Primary Squatters: Create at a **minimum** a Priority “F” EC Notification for **all** primary squatters. **Consider replacing crossarm instead of addressing squatter/replacing insulators as applicable.**

Consider assigning a higher priority to primary squatters that are:

- In wild land fire areas
- In areas where conditions may increase the risk of pole fires (coastal, dusty, high moisture)
- Wood pin or un-bonded steel pin
- Squatting at a hard angle
- Supporting large conductors
- Squatting due to significant deterioration of the crossarm

Secondary Squatters: Create an EC Form if compelling (needs to be addressed within 12 months)

Minor Work: No

Related Documents: 022088, Crossarm Evaluation TD-2305M-JA_07

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PRIMARY SQUATTER



At this Location: 2 Primary Wood Pin Squatters; best practice is to replace crossarm if more than 1 insulator needs to be replaced – or – if crossarm has signs of deterioration

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA = Crossarm Decayed/Rotten / Replace
  or
  FDA = Insulator / Primary Squatter / Repair
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

SECONDARY SQUATTER AND DECAYED CROSSARM



At this Location: Secondary Squatter and decayed crossarm

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA= Crossarm / Decayed/Rotten / Replace
- Priority ”E”, 3-12 months depending upon exposure

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Lightning Surge Arresters

1. Flashed/Blown

General Guidance:

Replace if the lightning arresters are already cut in the clear.

IF a damaged lightning/surge arresters is compelling, THEN create an EC Form

Minor Work: No

EC Form: Yes

- FDA: Lightning / Arrestor Broken/Damaged / Replace or Lightning Arrestor /Flashed / Replace
- Select the Priority and Due Date based the 'Probability & Impact Chart' and exposure risks

Related Documents: 031822

Markings

1. High Voltage Sign Not Installed as Required

General Guidance: Inspectors are required to look for missing or broken high voltage signs during inspections. If inspectors find missing or broken signs, they should install new signs as minor work if they have the appropriate materials and equipment, and can perform the work safely. If the inspector cannot install a sign as minor work, the inspector must create a Priority 'F' EC notification. Below is guidance on how to evaluate high voltage signage.

High Voltage Sign Requirements:

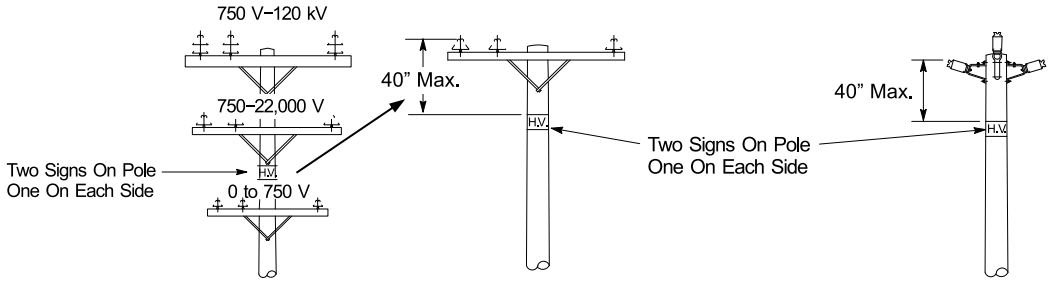
Poles that support line conductors or risers energized at **more than 750 volts** must be marked with high voltage signs. **IMPORTANT: If a pole is marked under any of the options below, it satisfies the high-voltage marking requirement.** When installing new high voltage signs using one option, inspectors are not required to remove signs previously installed under different options.

Marking Options:

A. **Sign the Pole Below the Lowest 750V+ Line Conductor (Preferred Method)**

Marking requirements are satisfied under this option if:

1. There are two signs, attached to the surface of each side of the pole[1].
2. The top of each sign is no more than 40'' below the lowest level line conductor that exceeds 750V.



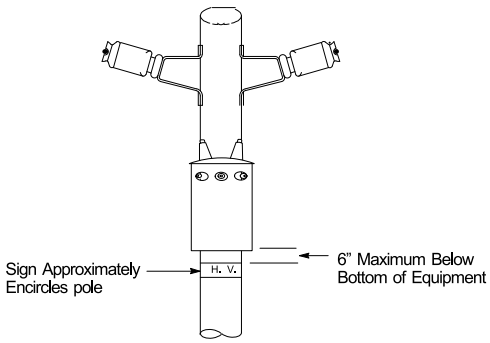
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[1] **Exception:** If an inspector finds only one high-voltage sign within 40'' below the lowest 750V or greater conductor, the inspector **is not required to install a second sign**. However, when performing work at the lowest crossarm level, a second sign must be installed.

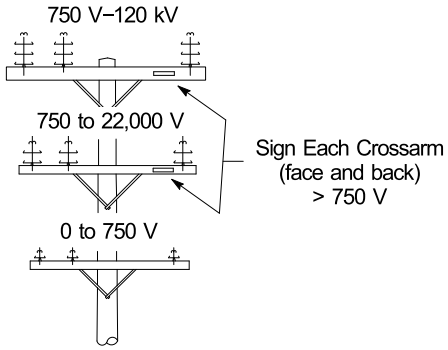
B. Sign the Pole Below Equipment
Marking requirements are satisfied under this option **if:**

1. There are two signs attached to the surface of each side of the pole[2].
2. The top of each sign is no more than 6'' below the equipment.
3. The signs are above all 0-750V supply and communication line conductors.

[2] **Exception:** If an inspector finds only one high-voltage sign installed within 6'' below the equipment, the inspector **is not required to install a second sign**. However, when performing work at the equipment level, a second sign must be installed.



C. Sign Each Crossarm
Marking requirements are satisfied under this option **if:**
1. Each crossarm (line arm) supporting line conductors in excess of 750V are signed both front and back. Signs are not required on the inside faces of double arms.



The exceptions in Sections A and B do not apply when, in the judgment of the inspector, the two high voltage signs should be installed so that they may be visible from all sides of the pole. Typical examples are poles near water areas suitable for sailboats, near established boat ramps and associated rigging areas, adjacent to swimming pools, and in agricultural areas with moveable irrigation piping.

Minor Work: Yes

Related Documents: None

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2. Operating Number Incorrect / Illegible/ Missing

General Guidance:

IF the operating number on the field equipment does **not** match the operating number printed on inspection map;

THEN (1) **contact the local Distribution Operation (DO)** to confirm the discrepancy and to get further instructions

(2) DO confirms the field equipment number is **correct;** then complete a **map correction**

(3) DO confirms the field equipment number is **not correct**; then **perform minor work to correct the operating numbers** on the field equipment

(4) DO **cannot confirm the operating number**; then get a PIN from DO and complete a **map correction** to get an operating number assigned

(5) DO confirms the field equipment number for equipment in the field that **does NOT** have a field equipment number installed; then **complete minor work to install the equipment number OR create an EC** to have M&C install the field equipment number

Note: Alpha characters may differ between divisions. Be sure to confirm the "number" with the local DO and PS&R Supervisor.

Operating number should be installed in the operating position; if missing, they should be installed on the operating position, not at the 6' level. Consider also adding the # at the 6' level for ease of identification for field EE's.

If operating number exists, is it legible (faded, etc.); if not legible replace them as minor work.

If operating number is not installed in the field, but on the inspection map - call the DO to confirm the correct number before installing.

If confirmed that the field is wrong, correct as minor work.

If confirmed that the operating number is mapped but not installed in the field, install the operating number as minor work.

Minor Work: Yes

Map Correction: Yes, if operating number needs to be corrected

EC Form: Yes, if you cannot perform minor work

- FDA: Marking / Broken/Damaged / Replace or Marking / Missing / Install
- Select the Priority and Due Date based the ‘Probability & Impact Chart’ and exposure risks

Related Documents: 057352

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FADED OPERATING NUMBER



Before: Faded operating number



Close-up



After: Minor work completed, operating number applied below operating position.

At this Location: Operating number is faded

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Marking / Broken/Damaged / Replace
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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3. Damaged or Missing Visibility Strips on Poles/Guy Markers

General Guidance: Reflective visibility strips shall be installed on wood, fiberglass, or steel poles, streetlight poles, and guy markers as follows:

A. On poles and guy markers installed on state highways.

B. On poles and guy markers located within 15 feet from the paved surface or 15 feet from the edge of the traveled, unpaved portion of city or county roads (streets) where not protected by curbs.

C. On poles and guy markers within 6 feet of an adjacent driveway, private roadway (street), turnaround, parking lot, or thoroughfare in rural district, capable of being traversed by vehicles, where these are not protected by curbs.

Notes:

Visibility strips are not required on poles or guy markers behind a curb, approximately 5-1/2” x 5-1/2” and 90 degrees to the surface.

Visibility strips should not be installed if there is no reasonable expectation of traffic. For example: Cross country poles, poles through waterways or wetlands, rear easements poles, poles behind guardrails, or poles on embankments that are well above or below the road.

Reminders:

- Do not install visibility strips on top of the old one. Inspectors must remove the old strip first.
- If the old strip is in good condition, but became loose, re-secure the strip to the structure.
- Do not install metal visibility strips over any vertical molding/riser.
- If any visibility strip work is required, bring the location up to the current visibility strip standard (all must be the same color – yellow)
- Install visibility strips on the side facing oncoming traffic when known.
- Do not install visibility strips within 1-1/2” of U-shaped molding

Minor Work: Yes

Related Documents: 022168, GO 95 Rule 56.9 (1964, 1990, 1996 Change to Guy Marker)

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ADHESIVE VISIBILITY STRIPS



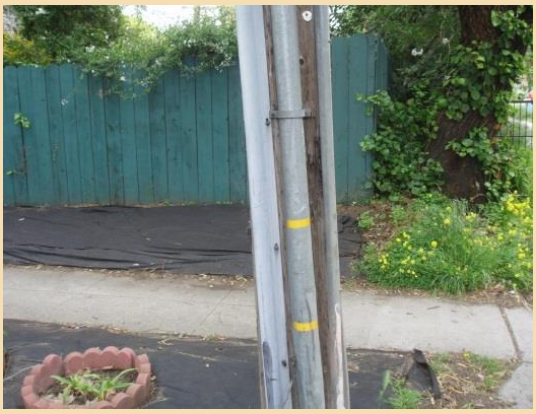
At this Location: Acceptable application of plastic and adhesive visibility strips

CLEARANCE FROM GROUND



At this Location: Acceptable metal visibility strips attached 1 ½“from ground.

INADEQUATE VISIBILITY STRIPS



At this Location: Pole with vehicular exposure. Two small sections of yellow adhesive visibility strips.

Perform Minor Work:

Yes, apply 3 adhesive visibility strips on the pipe.

Yes, apply 3 adhesive visibility strips to the plastic molding.

Write Third-Party Notification: No

Write EC Form: No, perform minor work

VISIBILITY STRIPS PAINTED OVER NO LONGER REFLECTIVE



At this Location: Visibility strips painted brown (3rd visibility strip located above not shown in picture)

Perform Minor Work: Yes, remove old visibility strips and install new.

Write Third-Party Notification: No

Write EC Form: No, perform minor work

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METAL OVER MOLDING



Before



After

At this Location: Metal visibility strips under wood molding and over wood molding with protruding edge.

Perform Minor Work: Yes, remove old metal visibility strips and apply new visibility strips; **visibility strips on after photo are fiber, not metal** (coded item)

Write Third-Party Notification: No

Write EC Form: No, perform minor work

OLD METHOD VISIBILITY STRIPS



At this Location: Aged visibility strips have lost reflectivity.

Perform Minor Work: Yes, replace with 3 yellow visibility strips

Write Third-Party Notification: No

Write EC Form: No, perform minor work

OLD AND NEW VISIBILITY STRIPS



At this Location: Yellow visibility strips mounted over old white visibility strips.

Perform Minor Work: Yes, remove old visibility strips

Write Third-Party Notification: No

Write EC Form: No, perform minor work

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Oil-filled Equipment

1. Equipment Oil: Leaking/Weeping Stain

General Guidance: Refer to the EDPM Manual - Assessments and Notifications Section for additional information about addressing oil in the field.

IF you observe a **stain or leak**

THEN (1) Look for **exposure or contamination**

Refer to the PCB Spill/Leak Category Response Matrix in order to determine the appropriate action:

PCB Spill/Leak Category Response Matrix
Overhead & Sub-surface Equipment

Indicator	PCB Equipment Manufactured Before July 1979		Non-PCB Equipment Manufactured July 1979 or later	
	EC Notification Priority	Standby at Site	EC Notification Priority	Standby at Site
Equipment has failed and insulating fluid has run off the surface of the equipment and is in contact with the soil, vegetation, or water.	A Replace	Yes	A Replace	Yes
Insulating fluid has run off the surface of the equipment and is in contact with the soil, vegetation, or water OR Insulating fluid is actively dripping.	A Replace	Yes	A Replace	Supervisor discusses with EFS to determine need to standby based on location and size of spill.
Insulating fluid is about to run off the surface of the equipment but has not made contact with the soil, vegetation, water, or structure.	A Replace	Yes	A Replace	Supervisor discusses with EFS to determine need to standby based on location and size of spill.

PCB Spill/Leak Category Response Matrix
Overhead & Sub-surface Equipment
(Continued)

Indicator	PCB Equipment Manufactured Before July 1979		Non-PCB Equipment Manufactured July 1979 or later	
	EC Notification Priority	Standby at Site	EC Notification Priority	Standby at Site
Insulating fluid is on the surface of the equipment and is **not** about to run off the surface and has **sheen** (Weeps or Seeps).	Supervisor discusses with EFS to determine EC notification category based on sensitivity of location and upcoming weather. IF no timely response from EFS within ½ hour, THEN assumed to be sensitive area.			
Sensitive Areas	A Replace	Not needed	B 3 month Recheck • Describe sheen in notification • Re-check in 3 months.	Not needed
Non-sensitive Areas	B 30 day Replace IF estimating cannot be completed in time to meet 30 day deadline, THEN replace with like.			
Residual stain is a mark on the equipment that appears dried. Examples: • Stain on side of overhead transformer • Stain on concrete	No further action needed	Not needed	No further action needed	Not needed

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PCB Spill/Leak Category Response Matrix, continued

PCB Spill/Leak Category Response Matrix
Padmount Equipment

Indicator	PCB Equipment Manufactured Before July 1979 2		Non-PCB Equipment Manufactured July 1979 or later	
	EC Notification Priority	Standby at Site	EC Notification Priority	Standby at Site
Equipment has failed and insulating fluid has run off the surface of the equipment and is in contact with the soil, vegetation, or water.	A Replace	Yes	A Replace	Supervisor discusses with EFS to determine need to standby based on location and size of spill.
Insulating fluid Is actively dripping either outside or inside the cabinet doors.	A Replace	Yes	A Contain & Clean Complete cleaning A, B, or E Replace	Supervisor discusses with EFS to determine need to standby based on location and size of spill.

Minor Work: No

Related Documents: TD-2320P-01 Attachment 4,TD-2305M-JA_05 Corrosion Evaluation

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2. Corrosion

General Guidance: In many parts of PGE's service territory, facilities are exposed to conditions that both cause and accelerate corrosion of metal components.

During detailed inspections, examine facilities and assess their condition. If corrosion is minor, repairs to the protective coatings that cover the metal surfaces on the equipment should be made. In addition, during the diagnostic testing for specific types of distribution line equipment, perform an examination for corrosion.

Minor Work: Yes

EC Form: Yes, if compelling

- Select the appropriate FDA
- Select the Priority and Due Date based the 'Probability & Impact Chart' and exposure risks

Related Documents: TD-2305M-JA_05 "Corrosion Evaluation Job Aid", G12020

IF you observe corrosion

THEN (1) Look for exposure

(2) Refer to the below table for to determine the corrosion rating and the required actions to perform. Visual examples follow:

Description	Symptoms	Required Actions
Integrity is breached	Hole(s) in metal (public exposure to high voltage, cover not securable, significant oil leak or spill, etc.)	EC notification Priority A – replace immediately or make safe and issue Priority B – replace/repair
Metal is damaged	Separation, layering, bubbling	EC notification Priority E – replace/repair Not to exceed 12 months
Moderate to heavy corrosion	No sign of metal degradation	Inspect at next interval Pad-mounted equipment – clean and paint
Little or no corrosion	Discolored paint, staining	No action required

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OH CORROSION EXAMPLES



At this Location: Corrosion Weakening Integrity of Tank

Metal is separation in to layers

Corrosion will breach tank

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form:

- FDA=Transformer Leaks/Seeps/Weeps Replace
- Priority ”E”, 3-12 months depending upon exposure



At this Location: Transformer with moderate/heavy corrosion

Metal structure still sound (rust staining from attachments)

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: No

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TRANSFORMER WITH STAINING, NO CORROSION	TRANSFORMER CASE WITH LITTLE OR NO CORROSION
	
At this Location: Transformer with dirt and salt spray staining, no metal damage	**At this Location:** Transformer with little to no corrosion, no metal damage
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: No	**Write EC Form:** No

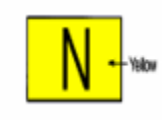
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Poles

1. Broken Poles

General Guidance: Observations in the field may include:

1. Broken
2. Split
3. Decayed / Rotten
4. Vandalized



An 'N' tag indicates previously identified damaged pole.

Minor Work: No

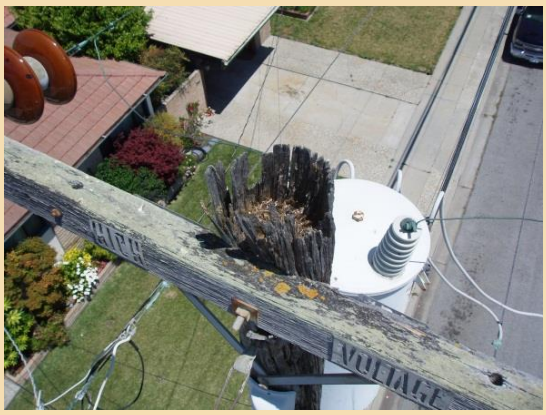
Related Documents: EDPM Pole Inspection, Utility S2325

POLE BROKEN AT THE COMMUNICATION LEVEL	POLE BROKEN AT MIDDLE SECTION
	
At this Location: Pole broken at the communication level in rural location. Complete Pole Inspection Test Report	**At this Location:** Broken pole. Complete Pole Inspection Test Report
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Pole / Broken/Damaged / Replace • Priority "B", 0-3 months depending upon exposure	**Write EC Form:** Yes • FDA=Pole / Broken/Damaged / Replace • Priority "E", 3-12 months depending upon exposure

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BROKEN POLE	POLE SPLIT AT COMMUNICATION LEVEL
	
At this Location: Broken pole. Complete the Pole Inspection Test Report. Pole supported in four directions.	**At this Location:** Pole split at communication level. Complete the Pole Inspection Test Report.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Pole / Broken/Damaged / Replace • Priority ”B”, 0-3 months depending upon exposure	**Write EC Form:** Yes • FDA=Pole / Broken/Damaged/ Replace • Priority ”E”, 3-12 months depending upon exposure

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DAMAGE TO POLE FROM SPECIFIC EVENT	DECAY OF POLE OVER TIME
	
At this Location: Pole burnt	**At this Location:** Pole top decayed. Entire pole failed pole test. Complete the Pole Inspection Test Report.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: No, not compelling upon detailed inspection from bucket. (If the inspector does not have a bucket, have an inspector with bucket perform inspection)	**Write EC Form:** Yes • FDA=Pole Decayed/Rotten/Replace • Priority ”E”, 3-12 months depending upon exposure

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SAW CUT INTO POLE



At this Location: Vandalized pole. Chain saw cut into lower portion of pole. Half of pole circumference cut into.

Notify supervisor of possible vandalism. Supervisor will have to communicate to damage claims. Complete Poles Inspection Test Report.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Pole / Broken/Damaged/ Replace
- Priority ”E”, 3-12 months depending upon exposure



At this Location: Vandalized pole. Chain saw cut into lower portion of pole. More than half of pole circumference cut into.

Notify supervisor of possible vandalism. Supervisor will have to communicate to damage claims. Complete Poles Inspection Test Report.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Pole / Broken/Damaged / Replace
- Priority ”B”, 0-3 months depending upon exposure

POLE DAMAGED ON THE BOTTOM BUT OK



At this Location: Pole damaged by vehicle. Splint installed as temporary repair. Inspection shows adequate circumference/strength. Sharp ragged splinters. Curb is adequate protection – visibility strips not required.

Perform Minor Work: Yes

Remove sharp edges, remove splint.

Write Third-Party Notification: No

Write EC Form: No, perform minor work

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DETERIORATION AROUND GROUND LINE



Before extraction



After extraction showing below ground deterioration

At this Location: Deteriorated condition found during normal inspection. Complete Pole Inspection Test Report

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Pole / Decayed/Rotten / Replace
- Priority ”A”, follow Emergency Process

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2. Leaning Pole

General Guidance: Consider the following when evaluating a leaning pole:

- Is the pole out of plumb by more than 10% of its height above the ground?
- Is the leaning pole causing excessive conductor sag?
- Does the lean appear as if it will become worse or affect safety or reliability in the next 12 months (considering environmental and configuration factors -soil, wind, pole attachments, equipment, guying)?

If the answer is **yes** to any of these questions, and in the inspector's judgment the pole is leaning excessively, **write an EC Form and fill out Pole Test Data Sheet**.

Note: If the Inspector suspects that a third party attachment is causing the pole to lean, consider writing a Third Party Utility notification vs. an EC Form.

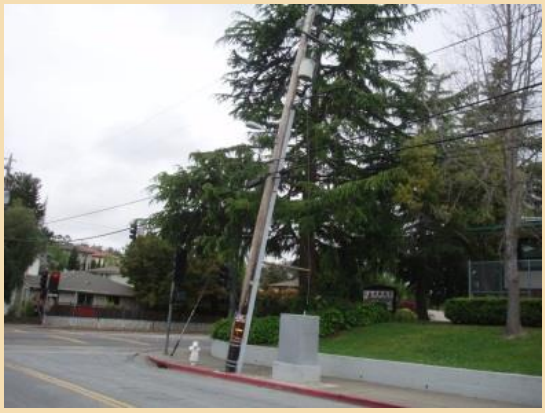
Minor Work: No

Related Documents: 023058

LEANING POLE	LEANING SLACK SPAN
	
At this Location: Leaning pole greater than 10% out of plumb. Pole is stable. No equipment in rural area.	**At this Location:** Leaning pole more than 10% out of plumb. Pole test indicates that pole is solid below ground and can be straightened. Probability of equipment failure is moderate.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: No (pole is stable)	**Write EC Form:** Yes • FDA=Pole / Leaning / Adjust • Priority "E", 3-12 months depending upon exposure

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STUBBED POLE LEANING TOWARDS SCHOOL



At this Location: Stubbed pole leaning towards school, supported by down guy. Pole Bands are loose due to additional deterioration of the pole. Pole test data sheet indicates that pole no longer meets stubbing criteria.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Pole / Decay/Rotten / Replace
- Priority ”E”, 3-12 months depending upon exposure

POLE LEANING 3 POT TRANSFORMER IN BUCK POSITION



At this Location: Pole is leaning less than 10% out of plumb, leaning in direction of offset equipment. Pole inspection found pole stable.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: No

POLE LEANING NEAR RAILROAD TRACKS



At this Location: Severe lean being held up by the primary conductors. Low clearance over active railroad tracks. Pole located in a swamp area with standing water.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Pole / Decayed/Rotten/ Replace
- Priority ”A”, follow Emergency Process

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3. Deformed Pole

General Guidance:

IF the pole is excessively deformed (bowing, bending, improper guying, no guying); THEN create an EC Form.

IF the pole is excessively deformed (bowing, bending, overloaded) due to communications; THEN create a Third-Party Utility Form.

Common drivers for deformed poles: Improper/lack of guying, third party attachment

Minor Work: No

Related Documents: EDPM Pole Inspection

POLE BENT 4 FEET OUT OF LINE	INADEQUATE SUPPORT AT COMMUNICATIONS LEVEL
	
At this Location: Pole bent 4 feet out of line, less than 10% lean. No evidence of pole damage.	**At this Location:** Two guys stabilizing communication level. No compelling issues.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes, only when the inspector decides that further assessment is required. • FDA=Pole / Overloaded / Test • Priority ”E”, 3-12 months depending upon exposure	**Write EC Form:** Yes, only when the inspector decides that further assessment is required. • FDA=Pole / Overloaded / Test • Priority ”E”, 3-12 months depending upon exposure

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OVER STRESSED POLE	UNBALANCED LOAD AT TOP
	
At this Location: Pole is twisted, cracked, due to communication.	**At this Location:** Deformed pole with bowed top in line with conductor with no visible breaks. No compelling condition.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Pole / Overloaded / Replace Pole Test Data Sheet is Required • Priority "E", 3-12 months depending upon exposure; add in field comments "overloaded by communications."	**Write EC Form:** No

4. Soil Excessively Eroded or Washed Away at Base of Pole

General Guidance: If the inspector notices that a large amount of soil was washed or eroded away at the base of a pole, consider writing an EC Form to investigate whether the pole still meets its designed set depth.

Minor Work: No

Related Documents: 015203

5. Pole Steps

General Guidance: Remove any pole steps less than 8 feet 6 inches above the ground or any other accessible surface; this allows for grading, landscaping, etc.

Minor Work: Yes

Related Documents: 022616 p.2

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6. Mud sill

General Guidance: Repair/replace deteriorated mud sill

Minor Work: No

Related Documents: 030109

7. Transmission Poles

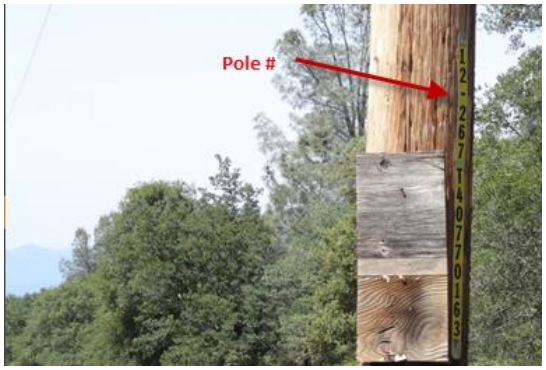
General Guidance: At minimum, when performing GO 165 patrols or inspections, Inspectors should perform a “patrol” of the transmission assets in the area being patrolled or inspected in order to identify any **obvious structural problems or hazards** that need to be addressed by the Transmission Organization.

Examples of the types of issues that could be identified:

- Damaged or broken poles
- Broken or decayed crossarms
- Broken insulators
- Damaged tie wire
- Vegetation issues

If you identify an obvious structural problem or hazard in the field that is NOT an emergency:

- Assign a location # of your map
- *Document the location # on your P&I Daily Log
- Take a photo of the pole # on the pole; example:



- Take a **minimum** of one photo to document the issue at the location
- Refer to the Transmission key contact map to identify the **T-Line contact** for that area
- Contact the appropriate **Transmission Supervisor** (leave a VM if not available)
- In the comments section of your log entry, note the following:
  - The issue identified (i.e. bad pole, broken crossarm, etc.)
  - The transmission pole #
  - The date, name and phone number of the T-Line employee that you contacted
  - The digital photo number(s) associated with the location

When in doubt call your Supervisor

Minor Work: No

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Riser Molding

1. Broken/Missing Riser Ground

General Guidance:

See 'Ground / Ground Molding' in this job Aid

Minor Work: None

Related Documents: 027742

2. U-Shape Riser Molding Broken/Damaged or Unsecured

General Guidance – Existing Molding:

Ensure bottom section of ground molding is flush against the pole

IF molding is NOT firmly attached to pole

THEN Perform Minor Work to secure molding to pole by attaching all lags ***OR*** Create EC Notification

Address any gaps identified via minor work or write an EC notification

General Guidance if Installing New Molding or Repairing Existing Molding:

Below 8 feet: Both sides of the molding must be secured to the pole at least every 18 inches

Above 8 feet: Both sides of the molding must be secured to the pole at least every 36 inches

Minor Work: Yes

Related Documents: 021924

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SmartMeter/SCADA Equipment

1. Broken/Damaged SmartMeter Relay/Access Point/Data Collector Unit or SCADA Equipment

General Guidance: If, through visual inspection, an inspector sees broken or damaged SmartMeter antenna, DCU, or SCADA equipment, create an EC Form. Be sure to check the SmartMeter box on the EC Form. If visible, note the operating number and/or serial number of the equipment.

Supervisors will contact SmartMeter Operations to notify them of the issue.

Minor Work: No

Related Documents: 072145, 072150, 068190, SMRT-9000WBT, 054422

EXAMPLES OF SMARTMETER ON POLE









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Streetlights

1. Broken or Damaged Streetlight Pole

General Guidance: Test for out-of plumb, then write an EC Form.

Minor Work: No

Related Documents: Utility S2309

MISSING STREET LIGHT	LEANING AGGREGATE POLE
	
At this Location: Cone indicates location of missing decorative street light and pole. Exposed wire is de-energized. Include picture of similar street light for replacement.	**At this Location:** Leaning aggregate pole more than 10% out of plumb. Pole is broken at base and not stable. Light still working.
Perform Minor Work: Yes, make safe.	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Streetlight / Missing / Install • Priority "B", 30 days for regular streetlights, add in field comment section if pole is missing. • Priority "E", 6 months for decorative streetlights, add in field comment section – describe if pole is missing.	**Write EC Form:** Yes • FDA=Pole / Broken/Damaged / Replace • Priority "B", 0-3 months depending upon exposure

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2. Day Burner

General Guidance: Do not create an EC Notification for a day burner. Call a clerk to contact Restoration Dispatch to get a T-Man to respond. This is to ensure correct accounting for streetlight work (depending on the rate that the customer is one, etc.).

Minor Work: Yes; if you have the materials on your truck

Related Documents: Utility S2309

3. Missing Streetlight

General Guidance: If the inspector notices that a missing streetlight, first, make safe then write an EC Form to install a missing streetlight.

Minor Work: No

Related Documents: Utility S2309

Trees

1. Trees within 18 Inches of a Primary Line

General Guidance:

Broken Limb on Conductor: Remove the limb as minor work with a hot stick if it is safe to do so.

Vegetation Touching Bare Conductor or Signs of Burning or Arcing: Create an emergency Priority “A” Vegetation Management Tag and call vegetation management for assistance. Wait at the location until relieved by Vegetation Management personnel.

Vegetation Not Touching Bare Conductor and No Signs of Burning or Arcing: Create a priority “B” Vegetation Management tag.

Minor Work: Yes

Related Documents: None

2. Trees within 4 Feet of a Primary Line (in State Responsibility Areas during Fire Season)

General Guidance: If the inspector sees a tree within 4 feet of a primary line in a state responsibility area during fire season, create a priority “B” Vegetation Management tag.

Note: Divisions with these areas are generally aware of the SRA; when in doubt, contact Vegetation Management or refer to GIS MapGuide

Minor Work: No

Related Documents: None

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3. Trees Causing Strain or Abrasion to a Secondary Conductor or Service

General Guidance:

If vegetation is:

A. Causing damage to the conductor insulation due to friction (Note: scuffing and polishing is NOT damaged) or

B. Causing strain on the conductor that is adversely affecting other supply facilities.

Note: The inspector should clear the vegetation or move the conductor as minor work if possible. Inspectors should leave the trimmings at the location; use door hanger to notify customer.

If the inspector cannot clear the vegetation or move the conductor:

- For service drops: Create an EC notification
- For secondary conductor spans serving 2 or more customers: Write a Vegetation Management notification with priority based on severity.

Note: Vegetation Management considers secondary as conductor that feeds more than one physical address (per Rule 16); i.e. multiple "service" conductors feeding the **same customer/property are considered service**, not secondary; Inspector will need to **write an EC** in this scenario

If the inspector sees a hazardous vegetation issue on communication facilities, create a third-party notification.

Minor Work: Yes

Related Documents: None

PHONE TREE CONDITION	
	**At this Location:** Tree putting strain on the pole, due to communication line **Perform Minor Work:** No **Write Third-Party Notification:** Yes **Write EC Form:** No

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SECONDARY HARD AGAINST TREE	SECONDARY OVERGROWN
	

At this Location: Secondary conductor resting on tree/vegetation

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Tree / Overgrown / Trim
- FDA= Conductor / Clearance / Adjust
- Priority ”E”, 3-12 months depending upon exposure

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Wildlife Protection

1. Existing Migratory Bird Protection Damaged

General Guidance: Inspector should write an EC Form to repair/replace existing bird protection installed in the field

Minor Work: No

Related Documents: Utility S2321, 061149

2. Existing Wildlife Protection Damaged

General Guidance: Inspector should write an EC Form to repair/replace existing wildlife protection installed in the field (cow guards, etc.)

Minor Work: No

Related Documents: 061149

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Clearance Evaluation Job Aid

TD-2305M-JA12
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Overhead Clearance Evaluation

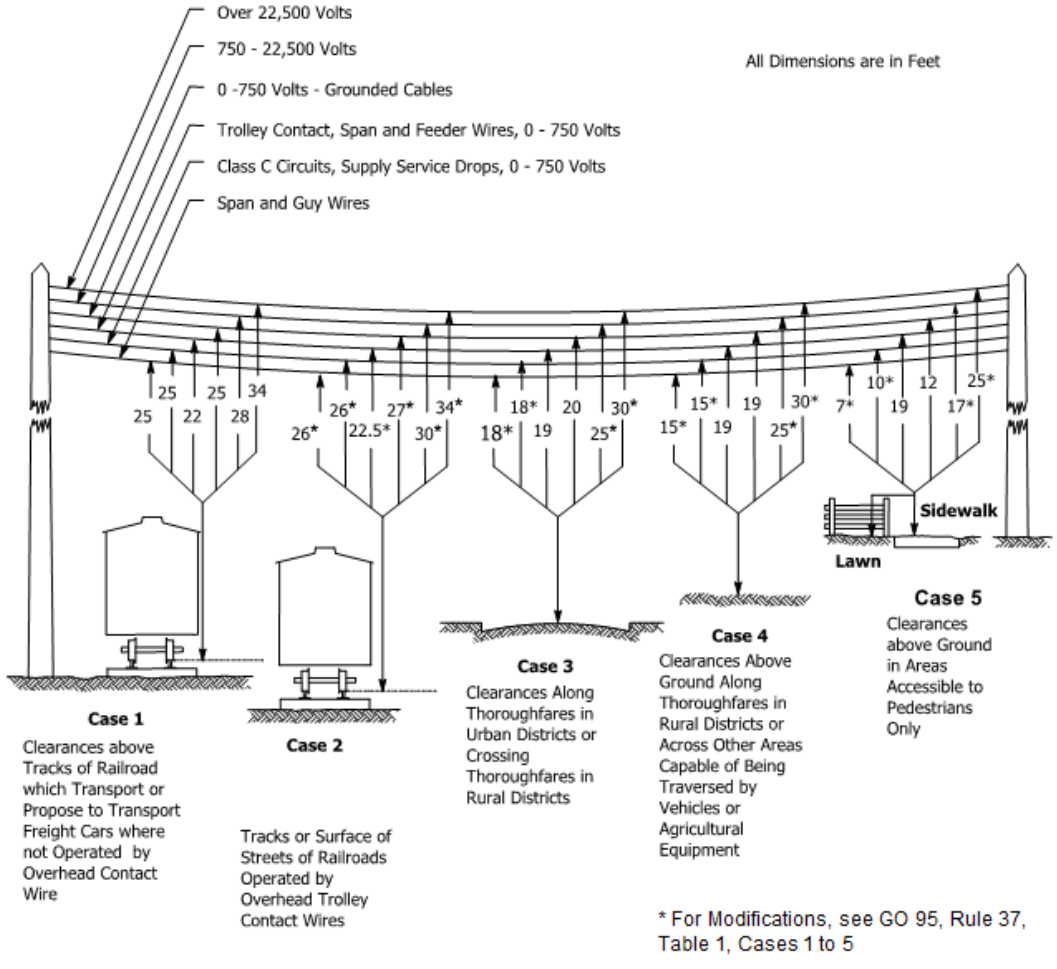
Guidance Document References:
TD-2305M – EDPM 2011 Manual
Engineering Document 022158 – Clearance Tables CPUC General Order 95

Level of Use:
- ❑ Information
- ✓ Reference
- ❑ Continuous

General Information

This job aid contains reference material to help compliance inspectors evaluate conductor clearance issues they visually identify in the field.

Ground Clearances - General



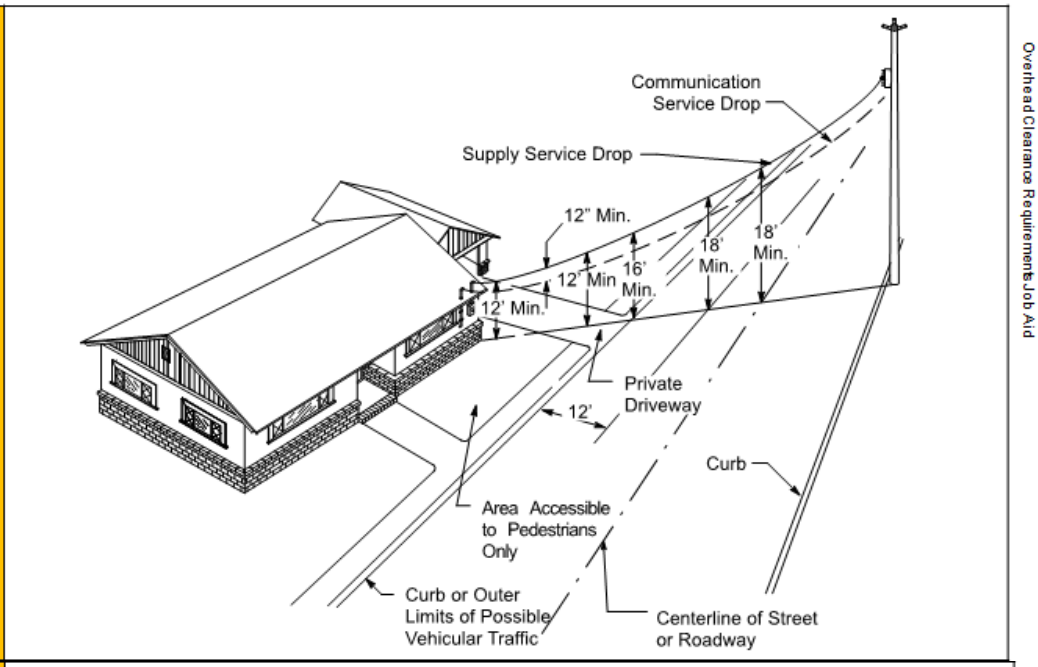
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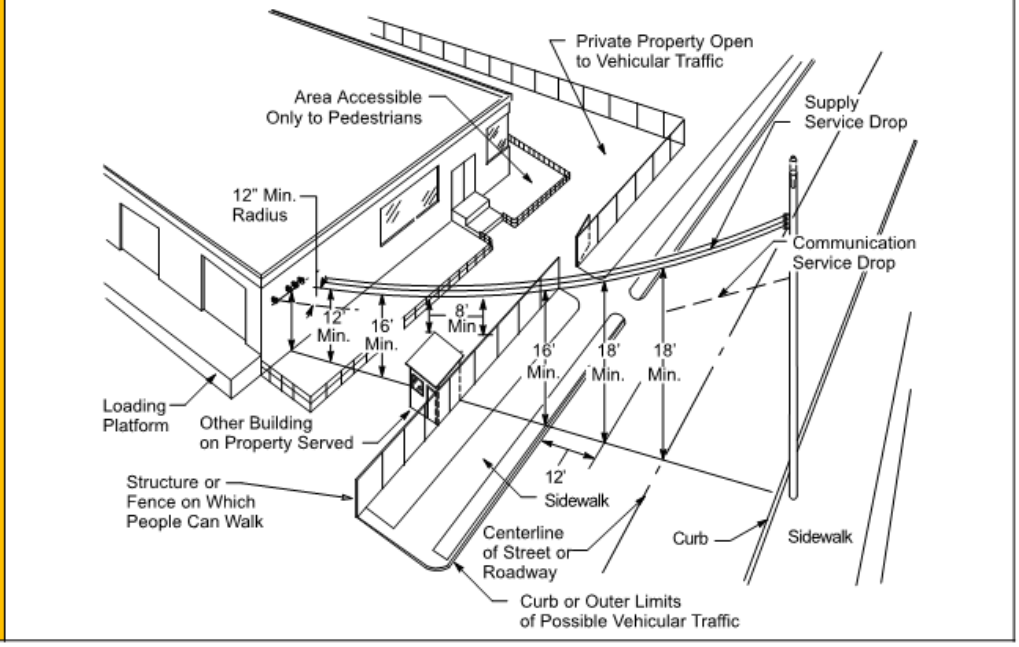
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Overhead Conductor Clearances

0-750V Service Drops - Residential



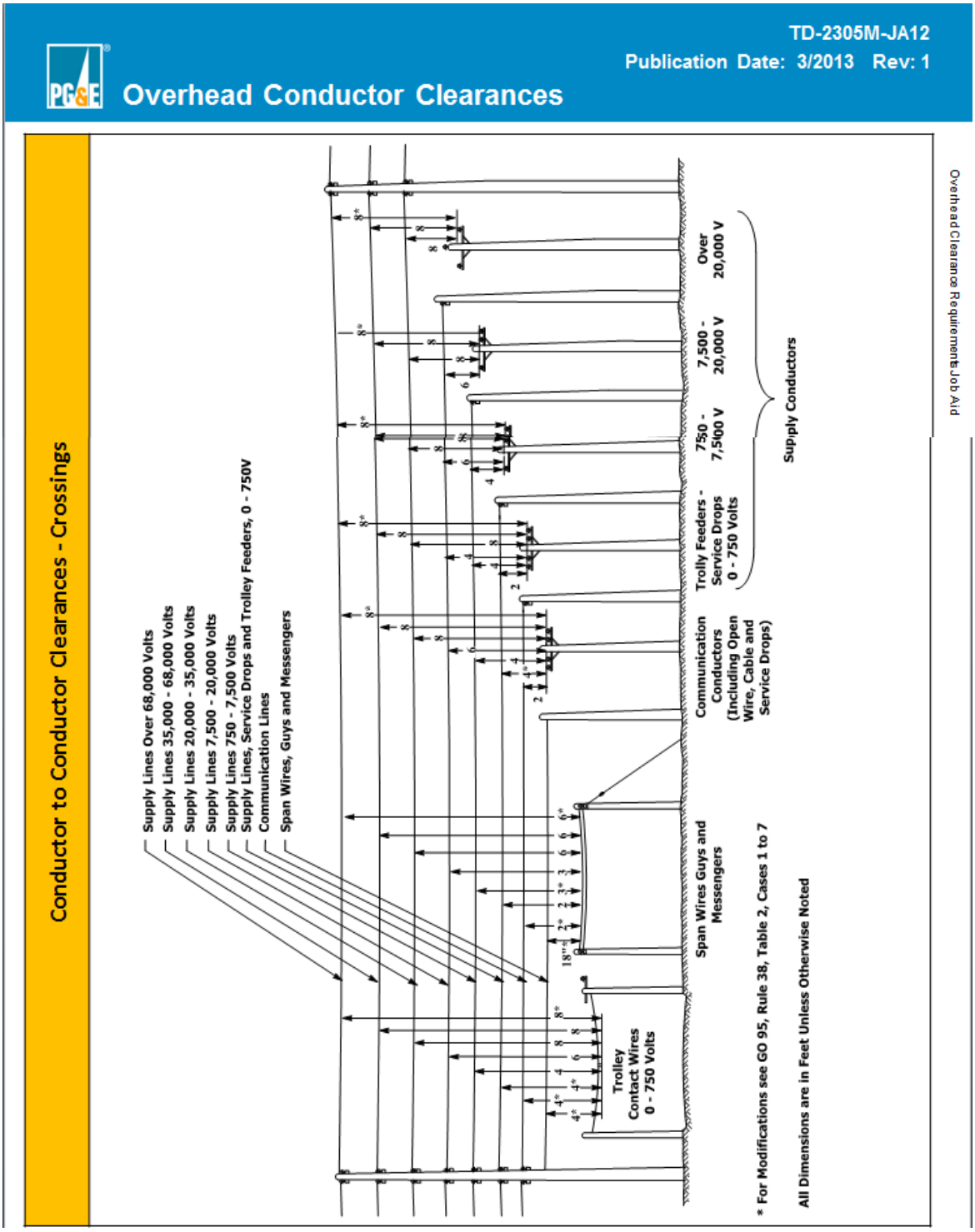
0-750V Service Drops - Industrial &Commercial



Overhead Clearance Requirements Job Aid

Page 2, Clearance Job Aid

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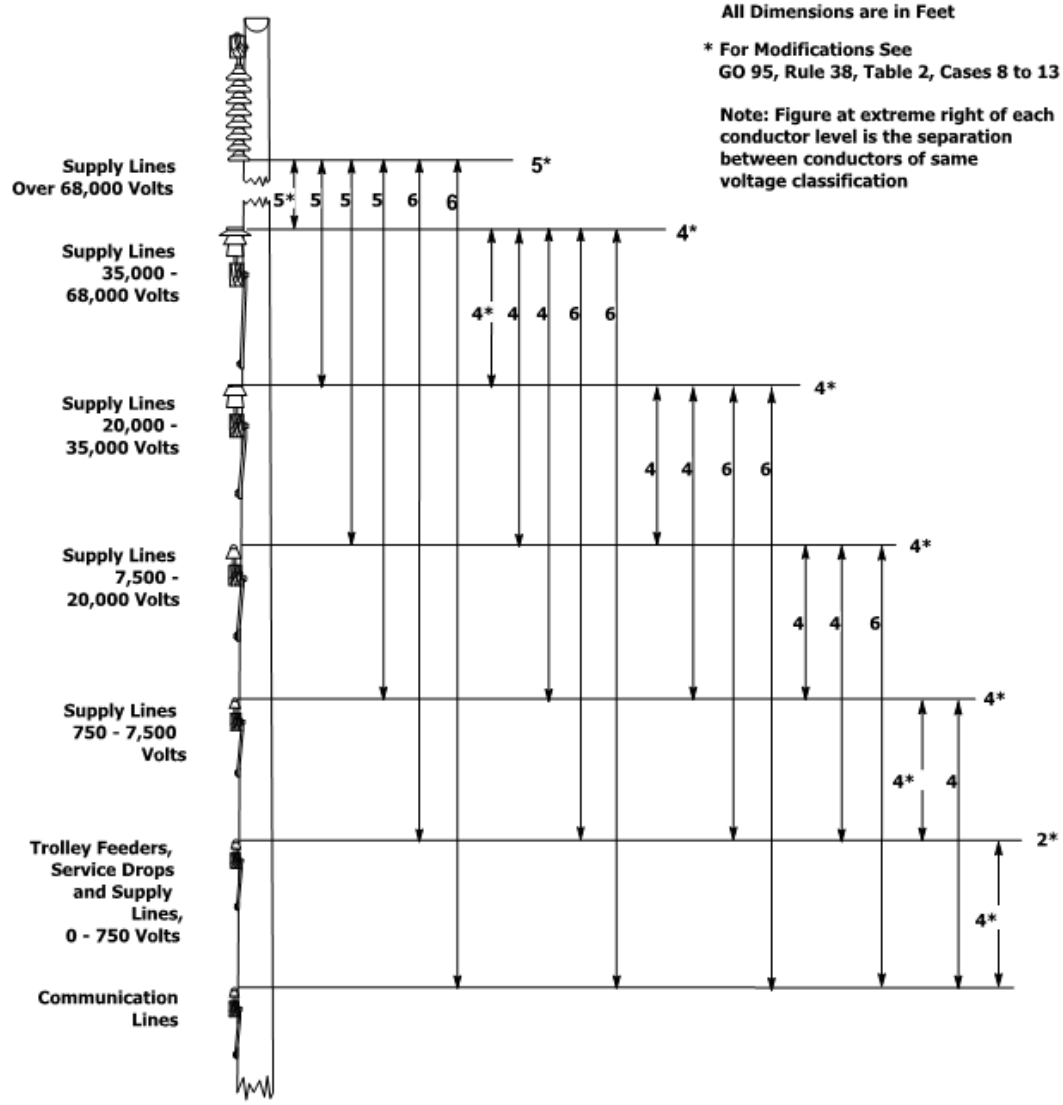
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Overhead Conductor Clearances

Conductor to Conductor Clearances – On Same Pole



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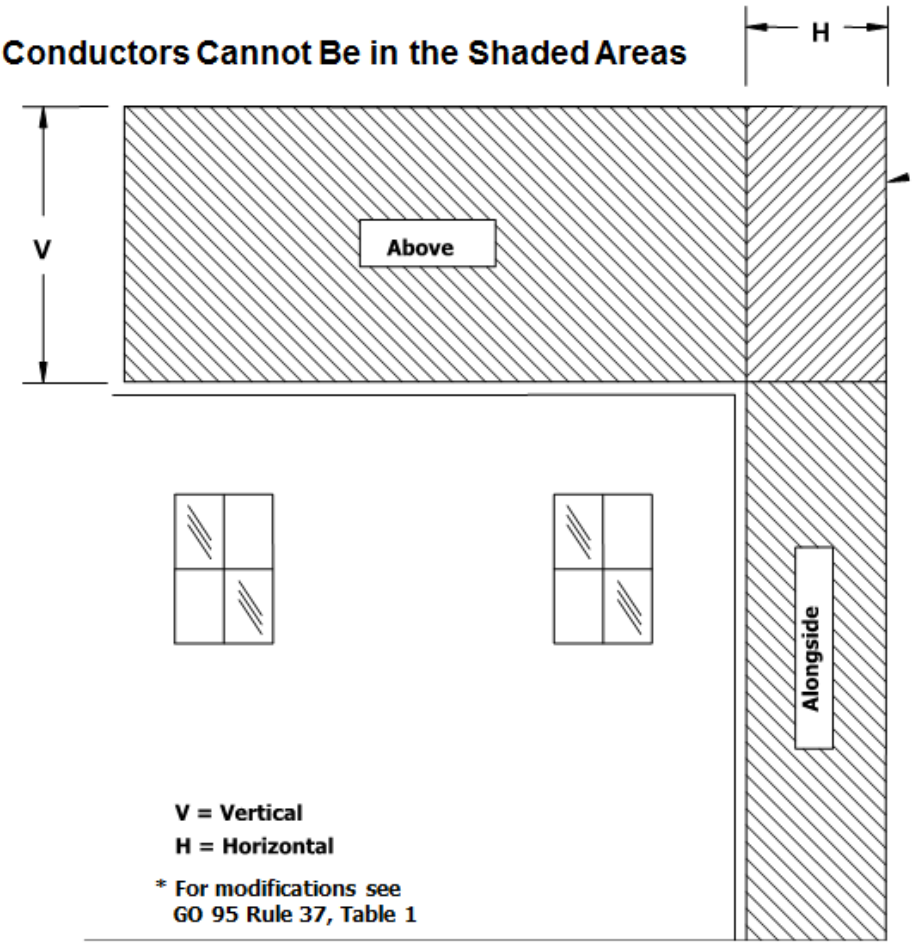
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Overhead Conductor Clearances

Conductor to Building Clearances

Conductors Cannot Be in the Shaded Areas



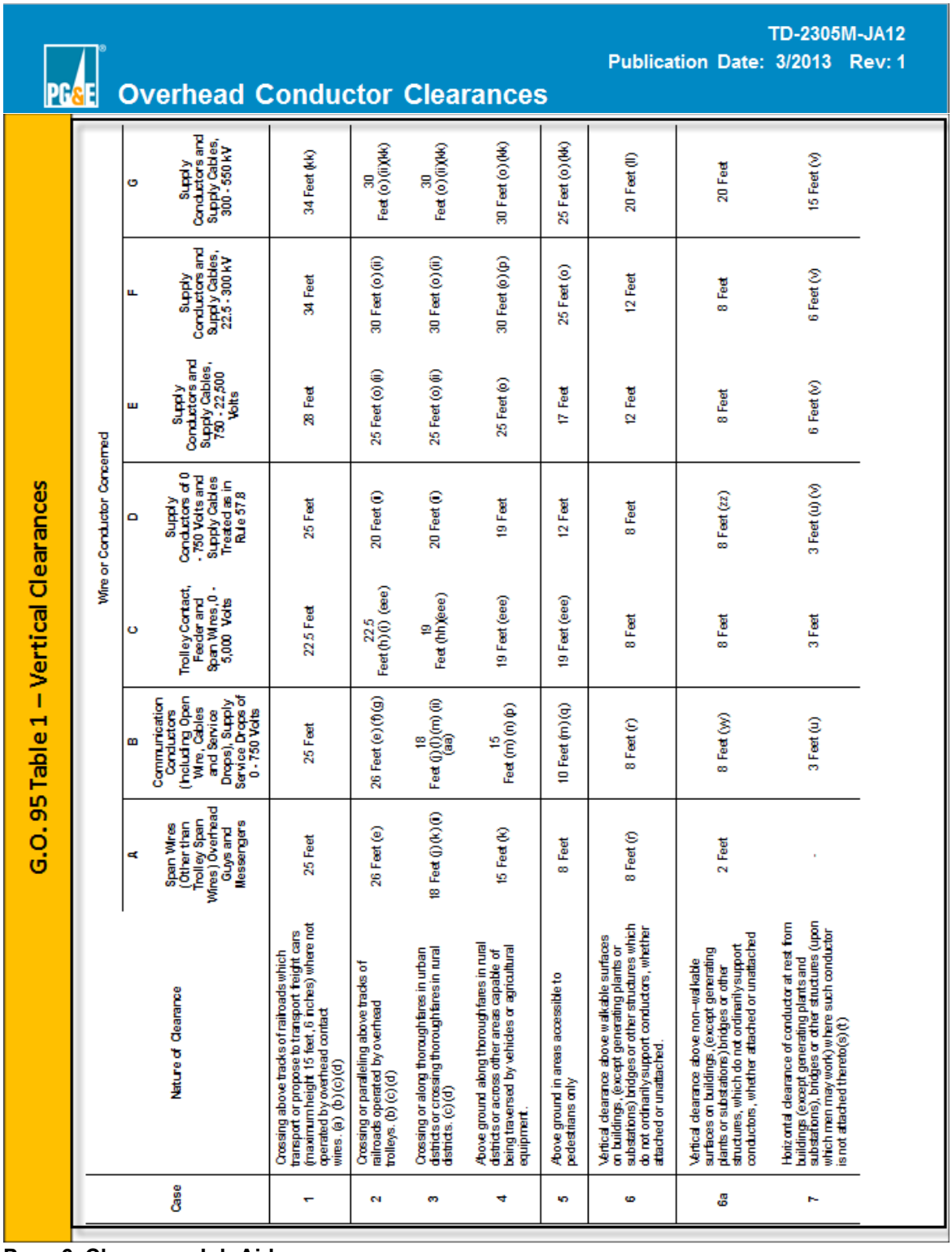
V = Vertical
H = Horizontal

* For modifications see GO 95 Rule 37, Table 1

	Conductor Type					
	Guys	Service Drops (not Attached)	0-750 V Spans	750V-22.5kV	22.5 – 300kV	300-550kV
V (Walkable Surface)	8 ft. *	8 ft. *	8 ft.	12 ft.	12 ft.	20 ft. *
V (Non-Walkable Surfaces: Handrails, Chimneys, Patio Covers, etc.)	2 ft.	8 ft. *	8 ft. *	8 ft.	8 ft.	20 ft.
H		3 ft. *	3 ft. *	6 ft.	6 ft. *	15 ft. *

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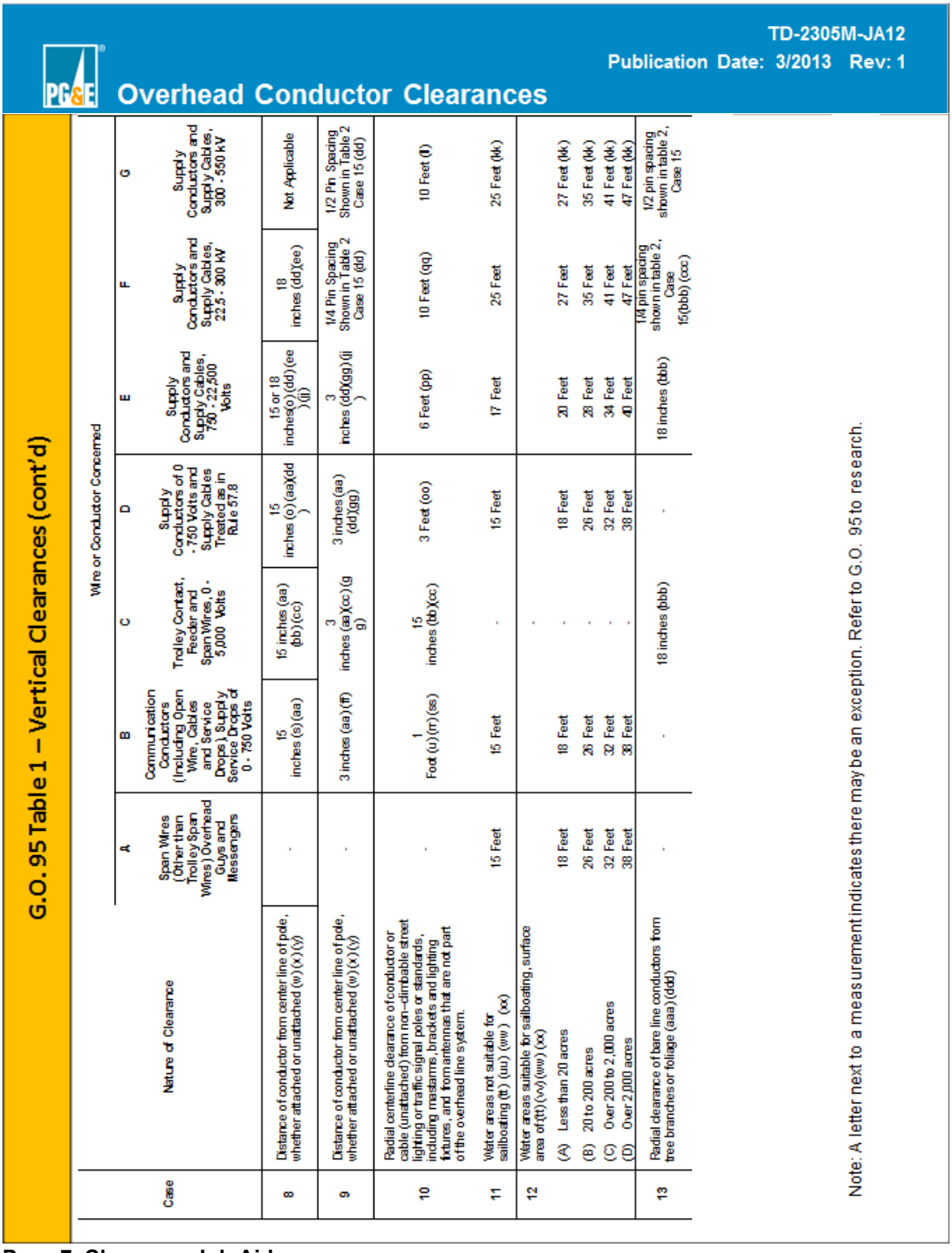
Overhead Conductor Clearances

G.O. 95 Table 1 – Vertical Clearances

Case	Nature of Clearance	Wire or Conductor Concerned						
		A	B	C	D	E	F	G
		Span Wires (Other than Trolley Span Wires) Overhead Guys and Messengers	Communication Conductors (Including Open Wire, Cables and Service Drops), Supply Service Drops of 0 - 750 Volts	Trolley Contact, Feeder and Span Wires, 0 - 5,000 Volts	Supply Conductors of 0 - 750 Volts and Supply Cables Treated as in Rule 57.8	Supply Conductors and Supply Cables, 750 - 22,500 Volts	Supply Conductors and Supply Cables, 22.5 - 300 kV	Supply Conductors and Supply Cables, 300 - 550 kV
1	Crossing above tracks of railroads which transport or propose to transport freight cars (maximum height 15 feet, 6 inches) where not operated by overhead contact wires. (a) (b)(c)(d)	25 Feet	25 Feet	22.5 Feet	25 Feet	28 Feet	34 Feet	34 Feet (kk)
2	Crossing or paralleling above tracks of railroads operated by overhead trolleys. (b) (c) (d)	26 Feet (e)	26 Feet (e)(f)(g)	22.5 Feet (h)(i) (eee)	20 Feet (i)	25 Feet (o) (ii)	30 Feet (o)(ii)	30 Feet (o)(ii)(kk)
3	Crossing or along thoroughfares in urban districts or crossing thoroughfares in rural districts. (c) (d)	18 Feet (j)(k)(ii)	18 Feet (j)(l)(m) (ii) (aa)	19 Feet (hh)(eee)	20 Feet (i)	25 Feet (o) (ii)	30 Feet (o)(ii)	30 Feet (o)(ii)(kk)
4	Above ground along thoroughfares in rural districts or across other areas capable of being traversed by vehicles or agricultural equipment.	15 Feet (k)	15 Feet (m) (n) (p)	19 Feet (eee)	19 Feet	25 Feet (p)	30 Feet (p)(p)	30 Feet (o)(kk)
5	Above ground in areas accessible to pedestrians only	8 Feet	10 Feet (m)(q)	19 Feet (eee)	12 Feet	17 Feet	25 Feet (o)	25 Feet (o)(kk)
6	Vertical clearance above walkable surfaces on buildings, (except generating plants or substations) bridges or other structures which do not ordinarily support conductors, whether attached or unattached.	8 Feet (r)	8 Feet (r)	8 Feet	8 Feet	12 Feet	12 Feet	20 Feet (ll)
6a	Vertical clearance above non-walkable surfaces on buildings, (except generating plants or substations) bridges or other structures, which do not ordinarily support conductors, whether attached or unattached	2 Feet	8 Feet (yy)	8 Feet	8 Feet (zz)	8 Feet	8 Feet	20 Feet
7	Horizontal clearance of conductor at rest from buildings (except generating plants and substations), bridges or other structures (upon which men may work) where such conductor is not attached thereto(s)(t)	-	3 Feet (u)	3 Feet	3 Feet (u) (vv)	6 Feet (v)	6 Feet (v)	15 Feet (v)

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Overhead Conductor Clearances

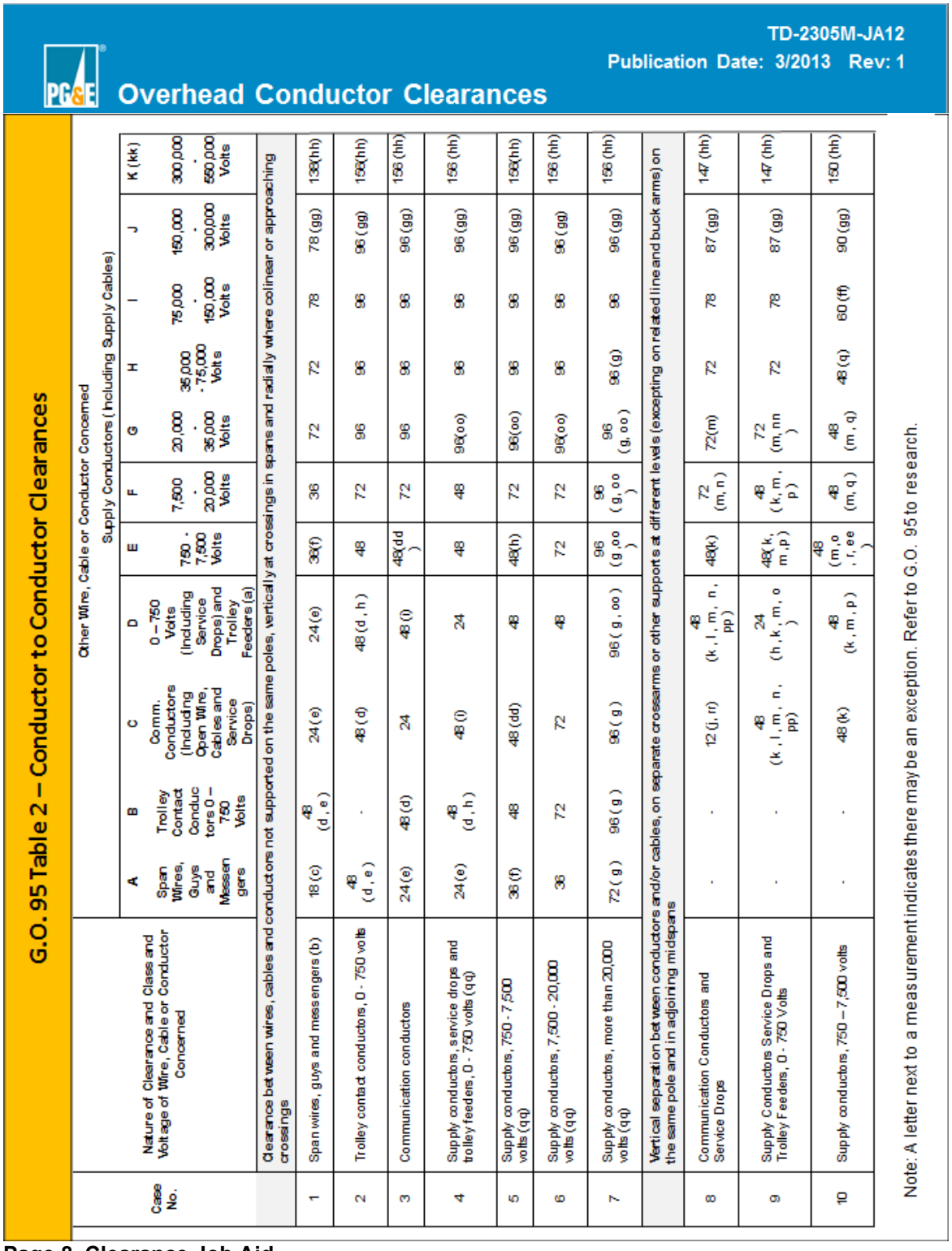
G.O. 95 Table 1 – Vertical Clearances (cont'd)

Case	Nature of Clearance	Wire or Conductor Concerned						
		A	B	C	D	E	F	G
		Span Wires (Other than Trolley Span Wires) Overhead Guys and Messengers	Communication Conductors (Including Open Wire, Cables and Service Drops), Supply Service Drops of 0 - 750 Volts	Trolley Contact, Feeder and Span Wires, 0 - 5,000 Volts	Supply Conductors of 0 - 750 Volts and Supply Cables Treated as in Rule 57.8	Supply Conductors and Supply Cables, 750 - 22,500 Volts	Supply Conductors and Supply Cables, 22.5 - 300 kV	Supply Conductors and Supply Cables, 300 - 550 kV
8	Distance of conductor from center line of pole, whether attached or unattached (w)(x)(y)	-	15 inches (s)(aa)	15 inches (aa)(bb)(cc)	15 inches (o)(aa)(dd)	15 or 18 inches(o)(dd)(ee)(ii)	18 inches (dd)(ee)	Not Applicable
9	Distance of conductor from center line of pole, whether attached or unattached (w)(x)(y)	-	3 inches (aa)(ff)	3 inches (aa)(cc)(gg)	3 inches (aa)(dd)(gg)	3 inches (dd)(gg)(ii)	1/4 Pin Spacing Shown in Table 2 Case 15 (dd)	1/2 Pin Spacing Shown in Table 2 Case 15 (dd)
10	Radial centerline clearance of conductor or cable (unattached) from non-climbable street lighting or traffic signal poles or standards, including mastarms, brackets and lighting fixtures, and from antennas that are not part of the overhead line system.	-	1 Foot (u)(rr)(ss)	15 inches (bb)(cc)	3 Feet (oo)	6 Feet (pp)	10 Feet (qq)	10 Feet (tt)
11	Water areas not suitable for sailboating (tt) (uu) (ww) (xx)	15 Feet	15 Feet	-	15 Feet	17 Feet	25 Feet	25 Feet (kk)
12	Water areas suitable for sailboating, surface area of:(tt) (vv)(ww) (xx)			-				
	(A) Less than 20 acres	18 Feet	18 Feet	-	18 Feet	20 Feet	27 Feet	27 Feet (kk)
	(B) 20 to 200 acres	26 Feet	26 Feet	-	26 Feet	28 Feet	35 Feet	35 Feet (kk)
	(C) Over 200 to 2,000 acres	32 Feet	32 Feet	-	32 Feet	34 Feet	41 Feet	41 Feet (kk)
	(D) Over 2,000 acres	38 Feet	38 Feet	-	38 Feet	40 Feet	47 Feet	47 Feet (kk)
13	Radial clearance of bare line conductors from tree branches or foliage (aaa)(ddd)	-	-	18 inches (bbb)	-	18 inches (bbb)	1/4 pin spacing shown in table 2, Case 15(bbb)(ccc)	1/2 pin spacing shown in table 2, Case 15

Note: A letter next to a measurement indicates there may be an exception. Refer to G.O. 95 to research.

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TD-2305M-JA12
Publication Date: 3/2013 Rev: 1

Overhead Conductor Clearances

G.O. 95 Table 2 – Conductor to Conductor Clearances

Case No.	Nature of Clearance and Class and Voltage of Wire, Cable or Conductor Concerned	Other Wire, Cable or Conductor Concerned										
		Supply Conductors (Including Supply Cables)										
		A Span Wires, Guys and Messengers	B Trolley Contact Conductors 0 – 750 Volts	C Comm. Conductors (Including Open Wire, Cables and Service Drops)	D 0 – 750 Volts (Including Service Drops) and Trolley Feeders (a)	E 750 - 7,500 Volts	F 7,500 - 20,000 Volts	G 20,000 - 35,000 Volts	H 35,000 - 75,000 Volts	I 75,000 - 150,000 Volts	J 150,000 - 300,000 Volts	K (kk) 300,000 - 550,000 Volts
	Clearance between wires, cables and conductors not supported on the same poles, vertically at crossings in spans and radially where colinear or approaching crossings											
1	Span wires, guys and messengers (b)	18 (c)	48 (d, e)	24 (e)	24 (e)	36 (f)	36	72	72	78	78 (gg)	138 (hh)
2	Trolley contact conductors, 0 - 750 volts	48 (d, e)	-	48 (d)	48 (d, h)	48	72	96	96	96	96 (gg)	156 (hh)
3	Communication conductors	24 (e)	48 (d)	24	48 (i)	48 (dd)	72	96	96	96	96 (gg)	156 (hh)
4	Supply conductors, service drops and trolley feeders, 0 - 750 volts (qq)	24 (e)	48 (d, h)	48 (i)	24	48	48	96(oo)	96	96	96 (gg)	156 (hh)
5	Supply conductors, 750 - 7,500 volts (qq)	36 (f)	48	48 (dd)	48	48 (h)	72	96(oo)	96	96	96 (gg)	156(hh)
6	Supply conductors, 7,500 - 20,000 volts (qq)	36	72	72	48	72	72	96(oo)	96	96	96 (gg)	156 (hh)
7	Supply conductors, more than 20,000 volts (qq)	72 (g)	96 (g)	96 (g)	96 (g, oo)	96 (g, oo)	96 (g, oo)	96 (g, oo)	96 (g)	96	96 (gg)	156 (hh)
	Vertical separation between conductors and/or cables, on separate crossarms or other supports at different levels (excepting on related line and buck arms) on the same pole and in adjoining midspans											
8	Communication Conductors and Service Drops	-	-	12 (j, rr)	48 (k, l, m, n, pp)	48(k)	72 (m, n)	72(m)	72	78	87 (gg)	147 (hh)
9	Supply Conductors Service Drops and Trolley Feeders, 0 - 750 Volts	-	-	48 (k, l, m, n, pp)	24 (h, k, m, o)	48 (k, m, p)	48 (k, m, p)	72 (m, nn)	72	78	87 (gg)	147 (hh)
10	Supply conductors, 750 – 7,500 volts	-	-	48 (k)	48 (k, m, p)	48 (m, o, r, ee)	48 (m, q)	48 (m, q)	48 (q)	60 (ff)	90 (gg)	150 (hh)

Note: A letter next to a measurement indicates there may be an exception. Refer to G.O. 95 to research.

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Overhead Conductor Clearances

G.O. 95 Table 2 – Conductor to Conductor Clearances (Cont'd)

Case No.	Nature of Clearance and Class and Voltage of Wire, Cable or Conductor Concerned	Other Wire, Cable or Conductor Concerned					Supply Conductors (Including Supply Cables)					
		A Span Wires, Guys and Messengers	B Trolley Contact Conductors 0 – 750 Volts	C Comm. Conductors (Including Open Wire, Cables and Service Drops)	D 0 – 750 Volts (Including Service Drops) and Trolley Feeders (a)	E 750 - 7,500 Volts	F 7,500 - 20,000 Volts	G 20,000 - 35,000 Volts	H 35,000 - 75,000 Volts	I 75,000 - 150,000 Volts	J 150,000 - 300,000 Volts	K (kk) 300,000 - 550,000 Volts
	Vertical clearance between conductors on related line arms and buck arms											
14	Line arms above or below related buck arms (s , t)	-	-	6	12 (u)	18 (u)	18 (u)	24	48	60 (ff)	90 (gg)	150 (hh)
	Horizontal separation of conductors on same crossarm											
15	Pin spacing of longitudinal conductors vertical conductors and service drops (v , w)	-	-	3 (x)	11½ (h , x)	11½(x)	17½(x)	24 (x)	48	60 (ff)	90 (gg)	150 (hh)
	Radial separation of conductors on same crossarm, pole or structure—incidental pole wiring											
16	Conductors, taps or lead wires of different circuits (v , y , s)	-	-	3 (x)	11½ (h , x)	11½(x)	17½(x)	24 (x)	48	60 (ff)	90 (gg)	150(hh)
16a	Uncovered, grounded, non-dielectric fiber optic cables on metallic structures, in transition (ss)	-	15	15	15	18	18	18	18	24	36	120
17	Conductors, taps or lead wires of the same circuit (v , s , aa)	-	-	3	3	6	6	12	24	60 (ff)	90 (gg)	150 (hh)
	Radial separation between guys and conductors											
18	Guys passing conductors supported on other poles, or guys approximately parallel to conductors supported on the same poles	-	-	3	11½	11½	17½	24	36	36 (ff)	78 (gg)	138(hh)

Note: A letter next to a measurement indicates there may be an exception. Refer to G.O. 95 to research.

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Crossarm Evaluation Job Aid

TD-2305M-JA_07
Publication Date: 01/01/2011, Rev: 1

Crossarm Evaluation

Guidance Document References:
TD-2305M – EDPM 2011 Manual
UO Guideline: G12021 - Electric Distribution Wood Crossarm Assessment

Level of Use:
- ☐ Information
- ✓ Reference
- ☐ Continuous

Crossarm Evaluation Job Aid

GENERAL INFORMATION:
Environmental conditions throughout the service territory expose support structures to a variety of conditions that can cause or accelerate deterioration of wood components. This section provides guidelines for assessing wood crossarms. Engineering requirements are identified in the Electric Distribution Wood Crossarm Assessment, Utility Guideline G12021.

Procedures:

During detailed inspections, examine wood crossarms and assess their condition. If the deterioration is minor, simple repairs (such as relocating/replacing pins or installing anti-split bolts) often can allow the arm(s) to remain in service for extended periods. However, more extensive decay or splits often cannot be repaired and require the arm to be replaced.

Crossarm Deterioration Ratings

Table 1 describes a five-level prioritization scale that maintenance inspectors should use as a guide to evaluate wood crossarm (including hanger and kicker arms) condition and determine corrective action as necessary. Where listed, time frames reflect relative priority.

Actual time frames must consider site-specific conditions such as crossarm configuration, number of phases, location (e.g., urban, rural, forest, inaccessible, traffic, etc.), loading (e.g., double/triple arms, dead ends, alley arms, proximity to trees, angle/conductor size, heavy loading, damaged wood pins, etc.), and the likelihood of these conditions contributing to further deterioration or failure of the crossarm or attached component.

Often crossarms experience significant decay on the top of the arm without exhibiting clues that are visible from the ground[1]. For this reason, arms that exhibit two or more of the following characteristics are more likely to decay on the top and should be considered for a more detailed aerial/climbing inspection:

- Arms that appear to be greater than 50 years old[2] (based on age of pole, presence of wood pins, brown/glass insulators, or other indicators).
- Arms mounted on poles where the pole top is showing signs of decay or crowning.
- Severely weathered arms or arms with rounded or apparently decayed ends.
- Damaged wood pins or elongated pinholes.
- Active moss/vegetation growth.
- Presence of woodpecker holes (greater than 1" diameter) on the arm.
- Arms in areas of high rainfall/moisture and reduced sunlight such as those in many coast and mountain areas.
- Wood pins on crossarms located in agricultural areas or orchards contaminated by aerial spraying and dirt, which contributes to tracking and arm or pin deterioration.

[1] Examples of top and bottom views of crossarm conditions are shown in Table 2.
[2] Many, but not all, crossarms supplied prior to 1955 were untreated.

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Crossarm Evaluation

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TABLE 1 - Crossarm Grading Aid

Table 1

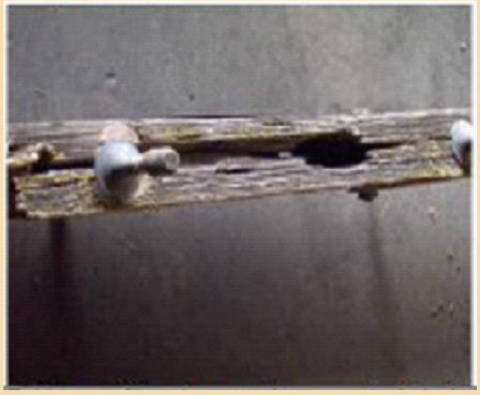
Description	Symptoms	Required Actions
Arm or conductors in danger of failing	Arm has moved off through bolt and is in danger of falling	**Priority A - Replace immediately - or - make safe and issue a Priority "B", 0-3 month EC, depending upon exposure** ***(Refer to Risk/Probability Matrix in Manual)***
	Arm splintering or completely broken/fractured	
	Arm/pole/wood pin is burning or tracking	
Significant Deterioration	Arm cracked, splintering, or evidence of burning/tracking but not in immediate danger of failing	**Priority "E", 3-12 months depending upon exposure** ***(Refer to Risk/Probability Matrix)***
	Split, insect, or decay/damage clear through the arm within 2" of pin/through bolt/brace holes	
	Prior temporary repair needs to be made permanent	
Moderate Deterioration	Active moss/vegetation growth covering more than 1/4 of the surface area of the face or top of crossarm (note: active vegetation growth by itself does not necessarily require replacement, but indicates conditions sufficient for decay that must be further investigated)	**Not a compelling condition that needs to be addressed in the next 12 months** ***(Refer to Risk/Probability Matrix)*** **No Action Required: Patrol/Inspect per next regular scheduled work for map**
	Split, insect, or decay/damage within 2" of pin/through bolt/brace holes	
	Enlarged or decayed primary steel pinhole causing squatter	
	Secondary floater	
	No compelling condition that needs to be addressed in the next 12 months (24 months for rural maps)	
	Note: Evidence of pole top decay, rounded ends, or decay at the bottom of a crossarm near pinhole typically indicates that the pole top and crossarm may need more detailed investigation to better assess the condition	
Little or no Deterioration	End of arm slightly rounded, small split, insect or minor decay/damage is more than 2" from pin/through bolt/brace holes	**No Action Required: Patrol/Inspect per next regular scheduled work for map**
	Weathered small sections of dried moss, or warped appearance with no visible signs of decay, tracking, or other deterioration	
	Missing knot	
	Crossarm obviously older than pole	
	Secondary squatter	
	Small woodpecker holes (<1" diameter)	
	Moss covering less that 1/4 of the surface on the top or face of the arm	
Crossarm issues are not "F-R"	Issues with crossarms are not regulatory, per GO 165 requirements; refer to above for "compelling" crossarm scenarios; *Refer to Risk/Probability Matrix*	

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Crossarm Evaluation

Table 2 – Crossarm Grading Aid

BOTTOM VIEW	TOP VIEW
Evidence of decay near hole 	Evidence of Significant Decay 
Enlarged hole, minor moss/discoloration/splits near pin hole 	Enlarged hole, minor moss/discoloration/splits near pin hole 
Evidence of tracking/burning near brace and pin holes 	Evidence of burning near brace and pin holes 

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Crossarm Evaluation

Corrosion Examples	
Arm completely broken/fractured	 Priority A (make safe immediately)
Primary squatter (wood pin). Split within 2" of pinhole .	 Priority B (Replace 0-3 months)

Crossarm Evaluation Job Aid

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Crossarm Evaluation

Corrosion Examples	
Secondary arm broken. Split/fractured within 2" of bolt holes in heavy tree area.	 Priority E (Replace 0-12 months).
Evidence of pole top and face of crossarm decay indicate need for more detailed inspection to better assess extent of arm top decay and condition and to determine if the remaining wood is sufficient to support the brace	 Priority E (Replace 0-12 months).
Significant Deterioration. Both arms are broken/split. Temporary repair needs to be made permanent.	 Priority E (Replace 0-12 months).

Crossarm Evaluation Job Aid

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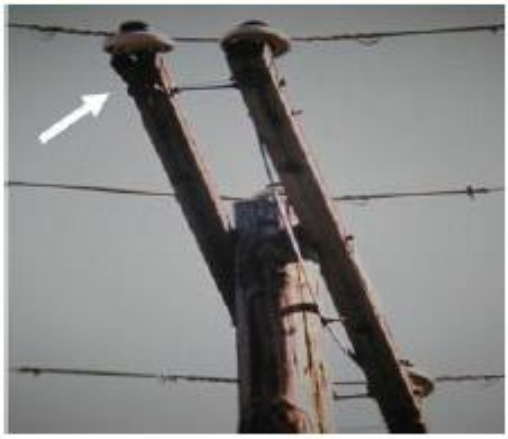
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Crossarm Evaluation

Crossarm Evaluation Job Aid

Corrosion Examples

Moderate Deterioration.	 • Split within 2" of pin. • No other evidence of damage, burning, decay. • Confirm if insulator on double arm is adequate to support strain • No Compelling Abnormal Condition • No repair or reporting required. • Inspect during next cycle.
Moderate Deterioration	 • Top of arm showing signs of decay / deterioration within 2" of each side of brace hole. • No Compelling Abnormal Condition • No repair or reporting required. • Inspect during next cycle.

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PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_124-Q006		
PG&E File Name:	GRC-2023-PhI_DR_TURN_124-Q006		
Request Date:	February 15, 2022	Requester DR No.:	TURN-PG&E-124
Date Sent:	March 2, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Katy Morsony

SUBJECT: PG&E-4, CHAPTER 10, OH AND UG ELECTRIC ASSET INSPECTIONS

QUESTION 006

Re. p. 10-9:3-10, PG&E states, "The detailed inspection checklist for distribution inspections includes 14 unique components across 55 questions/246 possible answers."

a. Please provide a copy of the referenced checklist (including the 14 unique components, 55 questions and 246 possible answers, and the objective and subjective criteria that PG&E uses to evaluate asset conditions and identify corrective actions).

b. Please provide a copy of the checklist that PG&E used for routine inspections prior to the WSIP.

c. If different than the checklist provided in response to Subpart b, please provide a copy of the EC Work Form that is referenced in the 2016 EDPM Manual (e.g., at p. 3 of the Inspections section (p. 127 of the PDF)).

ANSWER 006

a. Please see "GRC-2023-PhI_DR_TURN_124-Q006Atch01", "GRC-2023-PhI_DR_TURN_124-Q006Atch02", and "GRC-2023-PhI_DR_TURN_124-Q006Atch03" for checklists.

b. PG&E did not use a checklist for routine inspections prior to the WSIP.

c. Please see "GRC-2023-PhI_DR_TURN_124-Q006Atch04" and "GRC-2023-PhI_DR_TURN_124-Q006Atch05" for EC work form.

1	For Transmission Poles with Distribution underbuild, is Bridging absent from this pole? YES . NO □ N/A □ This is not a Transmission Pole with Distribution underbuild.	Inventory only
2	Are there any Tree Connects associated with this Pole? (Guidance: Tree Connects may include conductors, equipment, and guys.) Yes □ No □	Inventory only
2Photo	Photos if Yes, Attach photo of each Tree Connect* (Required)	Inventory only
2Comments	Comments:	Inventory only
2a	2a If yes, identify the direction in relation to the pole -- Drop Down (allow multiple selections) N/O (North of) S/O (South of) E/O (East of) W/O (West of)	Inventory only
2atakeoffComments	Comments: Enter additional take-offs	Inventory only
2aComments	Comments:	Inventory only
2b	2b If yes, how many Tree Connects are related to this pole?	Inventory only
2c	2c If yes, What type of conductor? Drop Down □Primary □Secondary □Service □Guying	Inventory only
2d	2d Is the tree dead or dying? Yes Create EC Notification FDA – TREE/VINE-DECAY/ROTTEN-INSTALL CL POLE No	Yes Create EC Notification
2e	2e Is there a clearance issue? Yes Create EC Notification FDA – TREE/VINE-DECAY/ROTTEN-INSTALL CL POLE No	Yes Create EC Notification
2f	2f Is there any damage caused by the Tree Connect to our facility? Yes create EC Notification FDA – TREE/VINE-DECAY/ROTTEN-INSTALL CL POLE No	Yes Create EC Notification
3	Are there any bolted Kearney connectors associated with this Pole on primary conductors? (Guidance: Kearney is the brand name for spilt bolt connector.) YES □ NO □	Inventory only
3a	3a If yes, how many?	Inventory only
3bPhoto	3b Photo* 1 photo is required	Inventory only
4	Are there any bolted PG connectors associated with this Pole on primary conductors? (Guidance: PG is a parallel grove connector.) YES □ NO □	Inventory only
4a	4a If yes, how many?	Inventory only
4bPhoto	4b Photo* 1 photo is required	Inventory only
5	Are there any Auto-splices on any spans associated with this pole? YES □ NO □	Inventory only
	5a If yes, How many auto splices	
5a	5a If yes, How many auto splices	Inventory only

5b	5b Direction of span? (Guidance: Count splices related to pole out to mid span in all directions; do not double count; include primary and secondary.) If yes, Drop Down – Drop Down (allow multiple selections) N/O (North of) S/O (South of) E/O (East of) W/O (West of) Comments: Enter direction of additional take-off points	Inventory only
5bCommnets	Comments: Enter direction of additional take-off points	Inventory only
5Comments	Comments:	Inventory only
6	Are there any Non-Exempt Fuse Cutouts, Switches, Split Bolt, or Chance Clamps associated with the pole? (Guidance: Look for equipment without snuffing capabilities; expulsion type of fuse; Lightning Arrestors, Switches with no LB's - KPF's, Grasshopper, Porcelain In-line Disconnects; Non-exempt cutouts may eject material.) YES □ NO □	Inventory only
6aCommentsDropDown	6a If Yes Select All that apply Robert – Add drop down, allow to select all Please identify the non-exempt equipment "Non-Exempt Equipment" Lightning ArrestorLA FUSE - Open LinkFUOL FUSE - UniversalFUUN CONNECTOR - Hot Lint Tap Clamp (NE)COHT CONNECTOR - Split BoltCOSB SWITCH - Grasshopper Air SwitchSWSG Solid Blade Disconnect (NE)SB Inline Solid Blade Disconnect (NE)SD Trip Saver IITRP2 Other (provide comments)OT	Inventory only
6aCommentsDropDown	Comments:	Inventory only
6b	6b If Yes Is there vegetation around the base of the pole? YES □ Create Vegetation Notification NO	Create Vegetation Notification
7	Is there any evidence of animal activity, nesting, damage or debris associated with the pole? YES □ NO□ If yes, Display Note: (1)Any condition that is a fire risk due to animal activity; Create EC Notification. (2)Any condition that caused a pole circumference reduction needs to be written up on an EC Notification; use FDA Pole / Overloaded / Test. (3)Create EC Notification to install animal mitigation if nest is already abandoned; use FDA Animal Mitigation / Mitigation Missing / Install.	Inventory only
7a	7a. What type of Animal activity? Drop down? Check all that apply □Bird □Raptor □Cattle □Deer □Bear/Mountain Lion □Snakes □Insects □Squirrels	Inventory only
7Comments	Comments	Inventory only
7Photos	Photos	Inventory only

8	Are there any improperly installed Chance Clamps associated with the pole. (Guidance: Identify improperly installed chance clamps (no armor rod under chance clamp for conductor smaller than 1/0 or installed incorrectly on tap line supporting more than 2 TXs or used on any other type of equipment (recloser, capacitor, regulator, etc.) other than a transformer. Chance Clamp is a brand name; this is a known as a hot-line clamp.) YES □ NO □ N/A □ There are no Change Clamps. If yes…	Inventory only
8a	8a Are tap guards missing for chance clamp connections? YES □ NO □	Inventory only
9	For transformer or equipment poles, are there any bushing covers and insulated jumpers missing at this location? (If one or both are missing, enter YES.) YES □ NO □ N/A □ This is not a transformer or equipment pole.	Inventory only
10	For transformer poles, are there Bushing Mounted Cutouts associated with the transformer? (Guidance: Inventory transformer poles with Bushing Mounted Cutouts.) YES □ NO □ N/A □ This is not a Transformer Pole.	Inventory only
11	Are there Flying Bells installed in the primary at this location? YES □ NO □	Inventory only
11a	11a If Yes, Are the Flying Bells Glass/Ceramic? YES □ NO □	Inventory only
12	What is the Pole Branding Height? (Guidance: Measurement from lowest ground level to branding; use feet and inches.)	Inventory only
13	Is there open wire secondary at this location? YES □ NO □	Inventory only
13a	13a If Yes, type of construction? □Rack Construction □Arm Construction	Inventory only
13b	13b If Yes, Is vegetation located within the conductors? (select one) □YES □ □NO □	Inventory only
13c	13c If Yes, identify severity of vegetation encroachment. □Low (Guidance: Low severity with little to no vegetation growth in the next 5 years.) □Medium (Guidance: Create EC Notification.) □High (Guidance: Create EC Notification.)	Create EC Notification if mod/severe
13Photo	If Yes, attach photo (photo is required).	Inventory only
14	14 Is Oil-Filled Transformer and/or Oil-Filled Equipment attached to this pole? YES □ NO □ N/A □ This is not a transformer or equipment pole.	Inventory only
14a	14a If Yes… Is the Oil-Filled Transformer and/or Oil-Filled Equipment showing signs of leaking, seeping, or weeping? (Guidance: Refer the PCB Spill/Leak Matrix to determine your action.) Robert—attach PCB matrix here YES □Create EC Notification per Matrix guidance NO □ N/A □ There is no Transformer or Oil-Filled Equipment at this pole.	Yes Create EC Notification (per matrix)

repairs. (2) When a Temp-Repair is observed answer "Yes"; otherwise, answer "No". (3) Examples of temp-repairs are documented in the Temp-Repair Job Aid.)

1 Did you observe Compelling Abnormal Conditions for the Pole, equipment, and its associated spans? (Guidance: A Compelling Abnormal Condition is a field condition that needs to be addressed in the next five (5) years.)

YES □
1a. (Check all that apply) Display for WSIP Only
□EC Notification (in Inspect App)
□Third-Party Utility Notification (in Inspect App)
□Third-Party Non-Utility Notification (in Inspect App)
□Vegetation Form (In Pronto)

1a. (Check all that apply) Display for GO165 Only
□EC Notification (in Inspect App)
□Third-Party Utility Notification (in Inspect App)
□Third-Party Non-Utility Notification (in Inspect App)
□Vegetation Form (Paper)
□Map Correction (Paper)
□Idle Facility (Paper)

1a. (Check all that apply) Display for GO165/WSIP Only
□EC Notification (in Inspect App)
□Third-Party Utility Notification (in Inspect App)
□Third-Party Non-Utility Notification (in Inspect App)
□Vegetation Form (Paper)
□Map Correction (Paper)
□Idle Facility (Paper)

NO □ There were no Compelling Abnormal Conditions for the Pole, equipment, and its associated spans.
Comments:

[Robert = If Q1=WSIP and If Veg form is checked then Display the Veg form in the Index]

1a.(Check all that apply)
1a.(Check all that apply)
Comments

2 Did you perform Minor Work? [Display for everyone]
YES □
No □

Minor Work = yes, [IF Q1=WSIP and Q1=GO165/WSIP display the following list]
Minor Work Drop Down Below 8' (check all that apply)
□Visibility Strips
□Ground Molding
□Guy Marker
□Other (provide comments)

Comments

Minor Work = yes, [IF Q1=GO165]
Enter Minor Work using Inspect App
2a.Minor Work Drop Down Below 8' (check all that apply)
Enter Minor Work using Inspect App

3 3a. What Plat Map are you inspecting?
3b. Is this the last pole in your assigned Plat Map?

Job Aid: Overhead Inspection

Summary

This job aid is designed to assist Inspectors in assessing and prioritizing compelling abnormal conditions on overhead facilities during scheduled GO 165 and Wildfire Safety Inspections.

It is meant to provide guidance on issues that Inspectors may encounter most frequently during an inspection and is not intended to be an all-inclusive listing of all abnormal conditions or corrective actions.

Field assessments are activities performed by Inspectors to identify Compelling Abnormal Conditions.

Compelling Abnormal Condition is defined as being any electric distribution pole, equipment, component, conductors, as well as trees, vines, vegetation and third-party infractions that may adversely impact public safety and/or service reliability in the next five (5) years.

Target Audience

Qualified Electrical Workers (QEW).

Before You Start

- Follow all applicable safety rules, procedures, and protocals.
- Wear appropriate personal protective equipment (PPE) for specific tasks and work area.

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Cellular Antennas

1. Broken/Damaged Cellular Antenna

General Guidance: If the broken antenna is creating a non-emergency safety or reliability issue, create a third party notification.

If the antenna is causing an emergency safety or reliability issue, contact your supervisor for instructions. Do not leave the location until it is made safe.

Minor Work: No

Related Documents: 027911

2. Cellular Antenna - Inadequate Clearance

General Guidance: Create a third party notification if a cellular antenna does not have adequate clearance from supply lines or equipment.

If the antenna is causing an emergency safety or reliability issue, contact your supervisor for instructions. Do not leave the location until it is made safe.

Minor Work: No

Related Documents: 027911, T&D Bulletin 2009-20

Climbing Space

1. Climbing Space - Obstructed

General Guidance: Evaluate pole to determine whether there is an obstruction caused by PG&E facilities or by third party facilities that is causing a compelling safety issue – based on the location of the pole and exposure to the worker - that needs to be addressed in 5 years.

Example: Equipment pole that cannot be accessed in a bucket truck.

Example where the climbing space **is not** a compelling condition: Equipment pole that is accessible 100% of the time in a bucket

For PG&E obstructions: Create an EC notification.

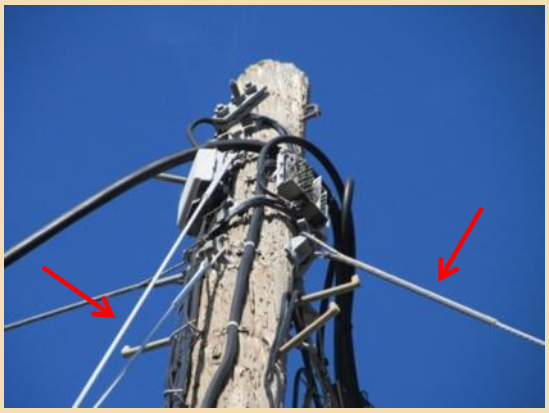
For third party obstructions: Create a third party notification if they pose a significant safety hazard.

If a third party obstruction is causing an emergency safety or reliability issue, contact your supervisor for instructions.

Minor Work: No

Related Documents: None

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COMMUNICATION IN CLIMBING SPACE	CLIMBING SPACE OBSTRUCTED
	
At this Location: Obstructed climbing space, access via bucket truck from street below. Also clearance issues between communications facilities and the PG&E down guys.	**At this Location:** Climbing space obstruction by communication facilities on pole with equipment. Communication messengers are too close. No bucket truck access.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third Party Notification: No	**Write Third Party Notification:** Yes
Write EC Form: No	**Write EC Form:** No

2. Climbing Space – Obstructed by Vegetation

General Guidance: For incidental vegetation in climbing space that can be moved when climbing, or quickly cleared prior to climbing, no action is required.

For major vegetation that cannot be quickly cleared or moved prior to climbing, evaluate the pole:

- Is there supply equipment on the pole that may need to be operated during emergency conditions?
- Should the obstruction be cleared for any other safety or reliability reason in the inspector's judgment?

If the answer is yes to any of these questions, the inspector will need to create an EC Notification to clear vegetation unless it can be addressed as minor work.

Minor Work: Yes

Related Documents: None

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OBSTRUCTED CLIMBING SPACE	CLIMBING SPACE OBSTRUCTED
	
At this Location: Obstructed climbing space. Inspector cannot see enough of the pole to complete Inspection (heavy vegetation, cannot see through) No equipment on pole. The only reason to address is to complete the inspection.	**At this Location:** Climbing space obstruction, able to perform inspection, no equipment on pole (able to see guys, able to see up the pole under tree)
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No, only need clearing to perform inspection	**Write Third Party:** No
Write EC Form: Yes • FDA=OH Facility / Limited Access/Obstruct / Inspect (Primary) • FDA=OH Facility / Limited Access/Obstruct / Remove • Priority ”B”, 0-3 months depending upon exposure; must complete before CPUC due date for map	**Write EC:** No, not compelling

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POLE WITH VEGETATION	IVY COVERED POLE
	
At this Location: 360° pole inspection not possible	**At this Location:** 360° pole inspection not possible
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA= OH Facility / Limited Access/Obstruct / Inspect (Primary) • FDA=OH Facility / Limited Access/Obstruct / Remove • Priority ”B”, 0-3 months depending upon exposure; must complete before CPUC due date for map	**Write EC Form:** Yes • FDA= OH Facility / Limited Access/Obstruct / Inspect (Primary) • FDA=OH Facility / Limited Access/Obstruct / Remove • Priority ”B”, 0-3 months depending upon exposure; must complete before CPUC due date for map

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Conductor

1. Conductor Broken/Damaged

General Guidance:

Visually check for damaged insulation (cracked, deteriorated, arcing, burn marks) and damaged conductor (corroded, frayed, deteriorated wire, annealing, broken strands, bird caging, etc.) and associated dead-end attachments throughout the entire span.

Visually check for excessively-corroded connectors and at bail-type dead-end hardware (potential to drop conductor).

Visually check all auto-splices in a span. Identify automatic splices tied in too close to the insulator preventing free movement of the splice with the conductor.

Check for any spans with uneven conductor. Look for annealed copper conductor (6 or 4 solid).

Identify improperly installed chance clamps (no armor rod under chance clamp for conductor smaller than 1/0; or installed incorrectly, installed on tap line supporting more than two transformers, or used on any other type of equipment (recloser, capacitor, regulator, etc.) - other than a transformer.

Identify and create EC Notification to replace Insulink and mini-wedges and all secondary connectors used in primary. Look for Kierney and PGs. Write EC Notification for those that appear to be corroded or damaged.

Inspect all connections made with dissimilar materials; write EC Notification to replace all bolted type connectors with dissimilar metals and those that are incorrectly connected. Copper over aluminum is incorrect. Look for signs of corrosion on all dissimilar connections and write EC Notification to replace when in question.

Install spreaders through vegetation to ensure 8" separation as needed or clear all vegetation.

For all open secondary wire, identify missing spreaders for >135 ft span, or for spans that are longer, install spreader brackets every 135' when possible otherwise, write EC Notification.

Minor Work: Yes

- Repair damaged conductor as minor work if possible and if safe to do so.

Minor Work: Yes

- Fill out an EC Form to account for this **capital** minor work
- Charge time to your Division’s standing order
- FDA: Conductor / Damaged / Replace
- Sign EC Form as completed
- IF not able to perform minor work, THEN write an EC Form.

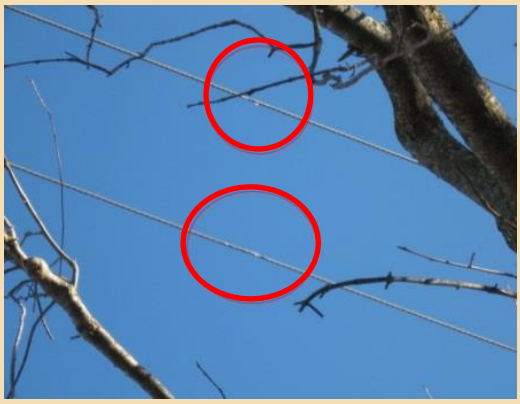
EC Form: Yes, if not able to perform minor work

- FDA: Conductor / Damaged / Replace
- Select the Priority and Due Date based upon Compelling Abnormal Conditions

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BROKEN SERVICE NEUTRAL	DAMAGED/CRACKED GREY SERVICE
	
At this Location: Broken service neutral	**At this Location:** Cracked grey service. Older Grey services tend to crack and will appear to have rings around the insulation.
Perform Minor Work: Yes, if safe to do so. If you replace the service conductor, this is capital Minor Work. Fill out EC Form to account for this minor work; charge time to your Division standing order	**Perform Minor Work:** Yes, if safe to do so. If you replace the service conductor, this is capital Minor Work. Fill out EC Form to account for this minor work; charge time to your Division standing order
Write Third Party Notification: No	**Write Third Party Notification:** No
Write EC Form: Yes, if minor work is not possible, or to document completed capital minor work • FDA=Conductor / Broken/Damage / Repair or Replace • Priority “A”, follow Emergency Process	**Write EC Form:** Yes, if minor work is not possible, or to document completed capital minor work • FDA=Conductor / Broken / Replace - *OR* • FDA=Conductor / Damaged / Replace - *OR* • FDA=Conductor / Burnt / Replace • Priority ”B”, 0-3 months depending upon exposure

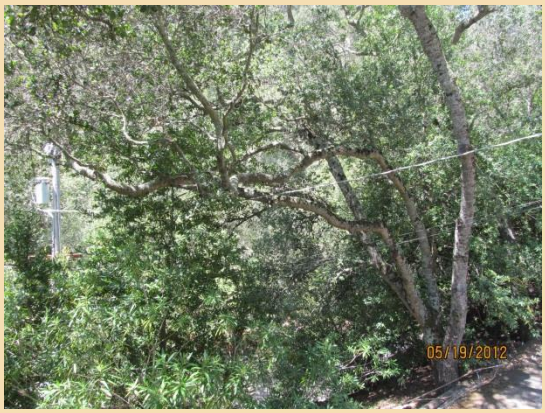
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DAMAGED SECONDARY	EXPOSED SERVICE CONNECTOR
	
At this Location: Damaged strands	**At this Location:** Exposed conductors
Perform Minor Work: No	**Perform Minor Work:** Yes, if safe to do so.
Write Third Party Notification: No	**Third-Party Notification:** No
Write EC Form: Yes • FDA= Conductor / Damage / Repair • Priority ”E”, 3-12 months depending upon exposure	**Write EC Form**: Yes, if minor work is not possible • FDA= Conductor / Broken/Damage / Repair • Priority ”E”, 3-12 months depending upon exposure

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CONDUCTOR TEARING APART	HARDWARE BROKEN
	
At this Location: Primary conductor damage (possibly shotgun)	**At this Location:** The #6 solid copper is broken causing strain on the conductor. Unsecured service.
Perform Minor Work: No	**Perform Minor Work:** Yes, if safe to do so
Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA= Conductor / Broken/Damage / Repair • Priority ”B”, 0-3 months depending upon exposure	**Write EC Form:** Yes, if minor work is not possible • FDA= Hardware/Framing / Broken/Damaged / Repair • Priority ”E”, 3-12 months depending upon exposure

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OVERHEAD SERVICE STRAIN ABRASION	OVERHEAD SERVICE STRAIN ABRASION
	
At this Location: Service strain abrasion, with possible burning at some sections. Damaged insulation.	**At this Location:** Service strain abrasion, no slack remaining
Perform Minor Work: Yes, if safe to do so. If you replace the service conductor, this is capital Minor Work. Fill out EC Form to account for this minor work; charge time to your Division standing order	**Perform Minor Work:** No
Write Third Party Notification: No	**Write Third Party Notification:** Yes
Write EC Form: Yes, if minor work is not possible, or to document completed capital minor work • FDA=Conductor / Broken/Damaged/ Repair or Replace • Priority ”E”, 3-12 months depending upon exposure, in comments add note about strain abrasion burnt conductor	**Write EC Form:** No

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2. Tie Wire Damaged

General Guidance:

Ensure auto-splices are not located under tie wires. Repair damaged secondary tie wire as minor work if possible.

Visually inspect hand ties to identify wear prior to failure with utilization of bucket truck, binoculars or camera, to get a closer look - especially on older installations.

Document damage to primary on an EC Form.

Minor Work: Yes, on secondary only

- Repair damage to secondary as minor work if possible and if safe to do so.
- IF not able to perform minor work, THEN write an EC Form.

EC Form: Yes, only if not able to perform minor work on secondary or primary damaged/broken

- FDA: Tie Wire/ Broken/Damaged / Repair or Replace
- Select the Priority and Due Date based upon Compelling Abnormal Conditions

Related Documents: 022088

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3. Floaters

General Guidance: For Floaters create an EC Form as an Emergency ”A” Priority Notification,for Primary or Secondary; always emergency; always stand-by.

Minor Work: No

Related Documents: 022088

FLOATER 4 KV



At this Location: Floater 4 KV, conductor is not contacting the arm. Rtten crossarm.

Perform Minor Work: No

Write Third Party Notification: No

Write EC Form: Yes

- FDA=Crossarm / Decayed/Rotten/ Replace
- Priority ”A”, follow Emergency Process

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4. Broken or Unsecured Service Bob

General Guidance: Repair or Replace broken insulator, wires, pins, etc.

Minor Work: Yes

- Make repairs as minor work if possible and if safe to do so.
- IF not able to perform minor work, THEN write an EC Form.

EC Form: Yes

- FDA: Hardware / Broken/Damaged / Repair or Replace
- Select the Priority and Due Date based upon Compelling Abnormal Conditions

Related Documents: None

5. Conductor Clearances (Refer to Clearance Job Aid)

6. Conductor: Uneven Sag

General Guidance: Look for any spans with uneven conductor - different tension, "bellies" (one is lower than conductor next to it) when wind blows, sway at different rates, etc., which could result in phase to phase contact. Look for damaged dead-end hardware (that would cause uneven sag). Look for signs of annealing, excessive sag, splices or discoloration that can result in failed conductor.

Identify clearance issues utilizing the Clearance Evaluation Job Aid.

Minor Work: Yes.

- Make repairs as minor work if possible and if safe to do so. Re-sag or install spreader brackets.
- IF not able to perform minor work, THEN write an EC Form.

EC Form: Yes

- FDA: Conductor / Sag / Adjust
- Select the Priority and Due Date based upon Compelling Abnormal Conditions

Related Documents: None

Cutouts / Fuses / Switches

1. Damaged Arcing Horns or Arc Quenchers

General Guidance: Call Restoration Dispatch to get a T-Man dispatched to the location to create a COE (CE) notification. Consider installing a warning tag on the pole. No EC should be created; write the location on map and Daily Log.

Minor Work: No

EC Form: No

Related Documents: 066195

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2. Damaged Bushing Mounted Cutout or Crossarm Mounted Cutout

General Guidance: Identify all locations with bushing mounted cutouts. IF hairline fractures / broken skirts are observed, THEN write an EC Form.

Equipment that has Non-Expulsion and/or arc snuffing ability is considered EXEMPT. Identify all locations with EXEMPT equipment.

For non-exempt equipment locations with Vegetation Management System (VMS) tagging: Write a Vegetation Notification if clearing around pole is needed.

Pole with Vegetation Management System (VMS) tagging.



Minor Work: No

EC Form: Yes

- FDA: Cutout / Broken/Damaged / Replace
- Select the Priority and Due Date based upon Compelling Abnormal Conditions

Related Documents: 056425

BROKEN DAMAGED CROSSARM MOUNTED CUTOUT	BROKEN INSULATOR ON AIR SWITCH
	
At this Location: Broken/Flashed cutout	**At this Location:** Broken insulator on air switch
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Cutout / Broken/Damaged / Replace • Priority ”E”, 3-12 months depending upon exposure • COE = No	**Write EC Form:** Yes • FDA=Cutout / Broken/Damaged / Replace • FDA Switch / Broken/Damaged / Replace • Priority ”E”, 3-12 months depending upon exposure • COE = Depending on voltage & Insulation value remaining if not operable

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3. Switch Handle/Control Box is not Locked

General Guidance: Ensure that boxes or enclosures located 8 feet or less above the ground are locked.

Minor Work: Yes

- Perform minor work if possible and if safe to do so.
- IF not able to perform minor work, THEN write an EC Form.

EC Form: Yes, only if not able to perform minor work

- FDA: Switch / Broken / Repair or Hardware / Missing / Install
- Select the Priority and Due Date based the 'Probability & Impact Chart' and exposure risks

Related Documents: 066195

Distribution Towers

General Guidance: Inspectors are required to inspect distribution towers for the following:

- Steel Covered by Earth
- Rust or Corrosion at Tower Footings
- Tower Footing Damaged
- Tower Member Loose
- Marking Hi-Sign Missing/Not Legible
- Guarding - Tower Not Guarded (Where Applicable)
- Guy Attachment, Turn Buckles, or Preformed Guys Loose
- Tower Rusty – Needs Paint

Minor Work: No

Related Documents: 022168, Utility Standard

Framing

1. Crossarm Broken/Deteriorated

General Guidance: Refer to TD-2305M-JA_07 "Crossarm Evaluation" Job Aid in this job aid. Evaluate crossarms to ensure all bolts and hardware are tight and present. Write up rolled over crossarms and loose hardware to be repaired or tightened.

If any crossarm needs to be addressed in the next 5 years, write EC Notification to replace crossarm with composite arm.

Minor Work: No

Related Documents: Crossarm Evaluation TD-2305M-JA_07, 015202, G12021

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2. Bridging Exists and Needs to be Repaired

General Guidance: Visual observation of broken / unattached bridge wire. Write an EC Form.

Identify all locations where bridging is absent.

Minor Work: No

Related Documents: 056845

BRIDGING	
	**At this Location:** Pole, burnt, pole failed **Perform Minor Work:** No **Write Third-Party Notification:** No **Write EC Form:** • FDA = Hardware/Framing / Broken/Damaged / Replace • Priority ”E”, 3-12 months depending upon exposure

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3. Underarm Bus Not Securely Attached

General Guidance:

It is a requirement to have at least two attachment points, secured to an underarm bus, one on each side.

It is a requirement to use the following corrosion resistant materials for attaching the underarm bus to the crossarm: straps, plumber's tape, lags, galvanized nails, staples, screws, bolts, zip ties, etc.

If an inspector finds an underarm bus secured with non-authorized material, such as duct tape, electrical tape, or rope, it must be secured by at least two additional approved attachment points.

When an inspector re-secures a bus, it must be brought up to construction standards; four attachment points using corrosion resistant materials.

Complete as minor work/re-secure the bus. IF it cannot be completed as minor work, then fill out EC if compelling and needs to be addressed within 5 years.

Minor Work: Yes

Related Documents: 021924, Crossarm Evaluation TD-2305M-JA_07

UNDER-ARM BUS LOOSE AND DETERIORATED



Side View



Front View

At this Location: UAB deteriorated, partial repair with rope, secured with one strap.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Under-Arm Bus / Broken/Damaged / Repair
- At minimum – must write up as Priority "F-R", next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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UNDER-ARM BUS LOOSE



At this Location: UAB Loose

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form:

- FDA=Under-Arm Bus / Broken/Damaged / Repair
  Priority ”E”, 3-12 months depending upon exposure

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4. Wood Pin Burnt/Tracking or Broken

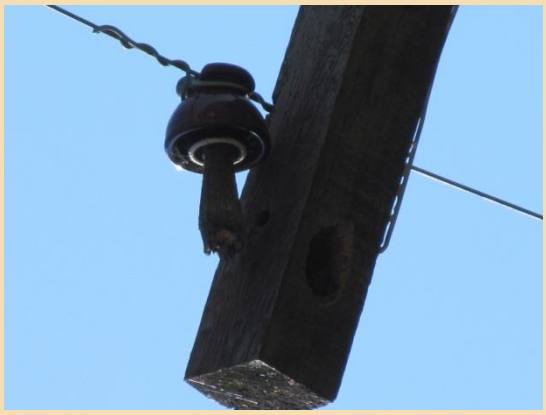
General Guidance:

Primary wood pins: If the primary wood pin is leaning or broken, or if there are signs of burning, or tracking, create a 0-3 month Priority “B” EC Form.

Secondary wood pins: Create an EC Notification if compelling (needs to be addressed within 5 years).

Minor Work: No

Related Documents: 015202, G12021, TD-2305M-JA_07 Crossarm Evaluation

PIN BROKEN	PIN BROKEN
	
At this Location: Primary wood pin is broken and the conductor is laying on the crossarm	**At this Location:** Secondary wood pin is broken and the conductor is laying on the crossarm
Perform Minor Work: No	**Perform Minor Work:** Yes, replace wooden pin with steel pin.
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Hardware/Framing / Broken/Damage / Replace • Priority ”A”, follow Emergency Process	**Write EC Form:** Yes • FDA= Hardware/Framing / Broken/Damage / Replace • Priority ”E”, 3-12 months depending upon exposure OR • Priority ”A”, follow Emergency Process, depending on location, exposure, etc.

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PRIMARY WOOD PIN AT ANGLE	PRIMARY WOOD PIN SQUATTER
	
At this Location: Deteriorated primary wood pin at angle. Crossarm is acceptable.	**At this Location:** Primary wood pin squatter. Crossarm is acceptable. No armor rod with hand-tie.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Hardware/Framing / /Broken/Damaged / Replace • Priority ”E”, 3-12 months depending upon exposure	**Write EC Form:** Yes • FDA=Insulator / Primary Squatter/ Replace • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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Grounds / Ground Molding

1. Exposed Ground below 8'

General Guidance: Exposed grounds 8 feet or less from the ground must be covered. Inspectors must make every effort to cover the ground as minor work. If the exposed ground can be completed as minor work - preferred repair method is to use 1 1/2 inch plastic molding and not wood molding; if wood molding is used to make repair, use straps and not staples.

If it is not possible to cover the ground as minor work, create a minimum priority 'F' EC Form. Consider a higher priority based on how much of the ground is exposed, and on the amount of public exposure. The correct FDA is Ground/Exposed/Repair and not Molding Broken/damaged/ repair or replace.

Gaps in between molding segments should be covered if, in the inspector's judgment, they are large enough to allow human contact.

Minor Work: Yes

Related Documents: Utility Bulletin TD-2999B-023

EXPOSED GROUND	
	**At this Location:** Exposed grounds near sidewalk **Perform Minor Work:** Yes, at a minimum make safe **Write Third-Party Notification:** No **Write EC Form:** Only if not able to perform minor work • FDA=Ground / Exposed / Repair • At minimum – must write up as Priority "F-R", next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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REPAIR WITH 1.5” MOLDING



Before: Copper Wire sticking out from under the wood molding



After: 1.5 inch u-shaped molding installed over existing wood molding

At this Location: Wood molding with ground exposed

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: Only if not able to perform minor work

REPAIR WITH 2” PLASTIC



At this Location: Condition acceptable after repair of exposed ground

REPAIR WITH WOOD MOLDING



At this Location: Condition acceptable after repair with wood molding

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2. Exposed Ground above 8' to the Communication Level

General Guidance: If there are communication facilities on the pole, exposed grounds above 8 feet to the communication level must be covered. Cover the ground as minor work if possible. If not, create an EC Notification.

Gaps in between molding segments should be covered if, in the inspector's judgment, they are large enough to allow human contact.

If the pole is not a joint pole, no action required, because there is no exposure to the communication worker.

Minor Work: Yes

Related Documents: 021904, 036229

EXPOSED GROUND AT COMMUNICATION LEVEL	EXPOSED GROUND DUE TO TWISTED MOLDING
	
At this Location: Exposed ground at communications level. Wood molding broken in climbing space.	**At this Location:** Exposed ground in wood molding.
Perform Minor Work: Yes, if safe to do so.	**Perform Minor Work:** Yes, when safe to do so.
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Only if unable to perform minor work. • FDA=Ground / Exposed / Repair • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)	**Write EC Form:** Only if unable to perform minor work. • FDA=Ground / Exposed / Repair • FDA=Molding / Broken/Damaged / Repair • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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3. Ground Molding Unsecured/Loose

General Guidance: Ensure that the molding is in good condition and secured to the pole.

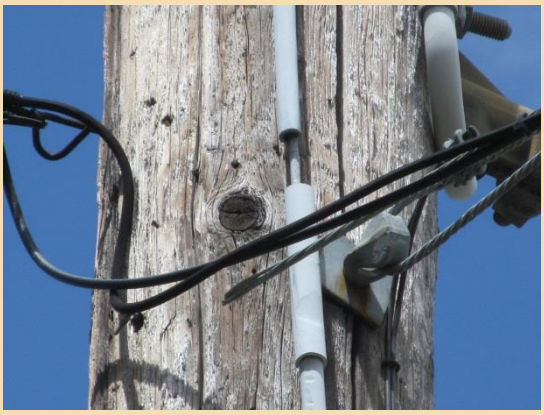
Look for unsecured and loose wood ground molding, unglued PVC ground molding joints, molding joints that have come apart exposing the ground wire, etc.

Gaps in between molding segments should be covered if, in the inspector's judgment, they are large enough to allow human contact.

When making repairs - must meet construction standards.

Minor Work: Yes

Related Documents: 02904

WOOD MOLDING NOT SECURE EXPOSING GROUND	PVC MOLDING NOT SECURE EXPOSING GROUND
	
At this Location: Wood molding not secure, allowing human contact.	**At this Location:** PVC molding not secure, due to failure of previous repairs, allowing human contact.
Perform Minor Work: Yes	**Perform Minor Work:** Yes
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Only if unable to perform minor work. • FDA=Ground / Exposed / Repair At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)	**Write EC Form:** Only if unable to perform minor work. • FDA=Ground / Exposed / Repair At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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PVC MOLDING SECURED	WOOD MOLDING SECURED
	
At this Location: PVC molding adequately secured with staples upon arrival. No action is required.	**At this Location:** Wood molding adequately secured with straps spacing 36 inches or less upon arrival. No action required.

4. Exposed Ground Rod

General Guidance: If the ground rod can be permanently covered as minor work, do so. If not, create an EC Form.

Minor Work: Yes

Related Documents: None

EXPOSED GROUND ROD	
	**At this Location:** Exposed ground rod **Perform Minor Work:** Yes **Write Third-Party Notification:** No **Write EC Form:** At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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5. Broken Ground

General Guidance: Inspector identifies a broken ground; refer to bulletin TD-2999B-023 for specific guidance about testing/replacing grounds

Minor Work: Yes

- Perform minor work if possible and if safe to do so.
- IF not able to perform minor work, THEN write an EC Form.

Related Documents: Utility Bulletin TD-2999B-023

Guys / Anchors

1. Down Guy Preform Buried

General Guidance:

Top of anchor head must be above grade. Expose anchor as minor work. Evaluate the unburied anchor guy pre-forms and visually inspect them.

Perform minor work to add extension or grade around anchor so the anchor head becomes visible, then no EC is required.

If the pre-form cannot be unburied as minor work, create an EC notification.

Notes:

- If you cannot dig up the anchor, and create an EC with a photo of a buried anchor **only** - the Gatekeeper will **not know** if the anchor can be replaced or if an extension can be installed; you should make every effort to dig up the anchor to perform a complete assessment. If your photo is of a buried anchor only, the general rule of thumb is that the EC will be created to **replace** the anchor.
- If you **cannot** dig up the anchor, but you can see most of the pre-form - an extension can *usually* be added (only one extension can be installed)

Minor Work: Yes

- Perform minor work if possible and if safe to do so.
- IF not able to perform minor work, THEN write an EC Form.

Related Documents: 022221

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BURIED ANCHOR



Before: Vegetation covers anchor



After: Vegetation cleared from anchor

At this Location: Anchor below grade overgrown with vegetation. After minor work inspector decides if the anchor can be adjusted or needs replaced.

Perform Minor Work: Yes, remove the vegetation
Yes, expose anchor and evaluate condition/corrosion
Yes, preferred method is to adjust anchor by adding extension

---

Write Third-Party Notification: No

Write EC Form: If cannot be addressed as minor work

- FDA=Anchor / Soil/Eroded/Graded / Replace (if the anchor cannot be adjusted)
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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ANCHOR EXTENSION



Anchor extension



Close-up

At this Location: Inspector performed minor work, exposed anchor, evaluated anchor to be in good condition so that extension could be installed, then installed extension. (Back fill not shown)

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: No

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ANCHOR COVERED BY CONCRETE



Anchor covered by concrete



Close-

At this Location: Anchor covered by concrete

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

FDA=Anchor / Soil/Eroded/Graded / Replace

At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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ANCHOR BURIED BY VEGETATION



Anchor buried by roots



Anchor buried by tree

At this Location: Anchor buried by ivy roots / tree

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Anchor / Soil/Eroded/Graded / Replace
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

2. Visible Portion of Anchor Rod has Significant Corrosion

General Guidance: IF the anchor rod is significantly corroded, THEN create an EC Form.

Minor Work: No

EC Form: Yes, only if not able to perform minor work

- FDA: Anchor Corroded Replace
- Select the Priority and Due Date based Compelling Abnormal Conditions and exposure

Related Documents: 025998

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ANCHOR ROD WITH SIGNIFICANT CORROSION



Anchor above ground



Below

At this Location: Corroded Anchor

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Anchor / Corroded / Replace
- Priority ”E”, 3-12 months depending upon exposure

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3. Guy Broken/Slack

General Guidance: Guys must be taut (straight, no belly). Tighten the guy as minor work if possible. If not possible, create an EC Notification.

If tightening the guy would exacerbate any pre-existing conditions on a facility (e.g. increase the lean of an already leaning pole, deform an already deforming pole), create an EC Notification with comments describing the situation.

Minor Work: Yes

Write EC: Select the Priority and Due Date based Compelling Abnormal Conditions and exposure

Related Documents: 022178

11.1 Guy Clearance

GUY CLEARANCE	GUY DAMAGED REPAIR
	
At this Location: Acceptable solution through plastic barrier. GO 95 requires 3” of radial clearance. Plastic barriers can be installed if less than 3” of clearance.	**At this Location:** Guy tail extends beyond the preform **near sidewalk**, safety hazard. **Perform Minor Work:** Yes **Write Third-Party Notification:** No **Write EC Form:** Only if minor work cannot be performed. • FDA Guy / Broken/Damaged/ Repair • Priority ”E”, 3-12 months depending upon exposure

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OVERGROWN GUY	TREE GROWING AROUND GUY
	
At this Location: Extensive dead ivy covering half of length of guy.	**At this Location:** Tree growing around guy
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Guy / Broken/Damaged / Replace • Priority ”E”, 3-12 months depending upon exposure	**Write EC Form:** Yes • FDA=Guy / Broken/Damaged / Replace • Priority ”E”, 3-12 months depending upon exposure – **OR -** • FDA=Guy / Overgrown / Trim • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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SLACK GUY



At this Location: Loose guy on left side

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: Yes, only if minor work is not possible

- FDA=Guy / Loose / Adjust
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

GUY GROUNDED BY VEGETATION



Guy grounded by vegetation



Guy grounded by vegetation



Guy overgrown by vegetation

At this Location: Guy grounded by vegetation, above the bob.

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: Yes, only if minor work cannot be performed

- FDA=Guy / Overgrown / Trim
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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IVY ON GUY AND PRIMARY



At this Location: Ivy on guy and on primary. Safety issues, possible energized guy and pole, transformer weeping – no oil on ground, evaluate per oil spill matrix.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Transformer / Leaks/Seeps/Weeps / Replace (primary)
- FDA=Guy / Overgrown / Trim
- Priority ”B”, 3 months or less depending upon exposure

TREE LIMB GROWING AROUND GUY



Guy through tree



Close-up

At this Location: Tree limb growing around guy, below the bob.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Guy / Strain/Abrasion / Remove
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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4. Guy Insulator Broken/Missing

General Guidance: Guys in the cylinder of “proximity” to conductors less than 35kV:

- 8 ft. or less above or below the conductor level
- 6 ft. or less horizontally from the surface of the pole

Must be sectionalized and ungrounded. Ensure there is an intact guy insulator.

Minor Work: No

EC Form: Yes

- FDA: Guy / Broken/Damaged / Replace or Guy / Missing / Install
- Select the Priority and Due Date based Compelling Abnormal Conditions and exposure

Related Documents: 022178

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5. Down Guy Grounded above Guy Insulator (vegetation or other)

General Guidance: Ensure that all guys are not grounded above the guy insulator. Remove any foreign objects (e.g. vegetation) contacting and grounding the guy above the insulator as minor work. Clear so that new growth will not contact or ground the guy. (Rule of thumb is that growth per year is 1 foot, so trim back 5 feet.)

Minor Work: Yes

Related Documents: 022178

DOWN GUY GROUNDED ABOVE GUY INSULATOR	DOWN GUY GROUNDED ABOVE GUY INSULATOR CAUSING STRAIN AND ABRASION
	
At this Location: Vine growing up and across the guy insulator grounding the guy.	**At this Location:** Tree grounding the guy above the guy insulator causing strain and abrasion.
Perform Minor Work: Yes	**Perform Minor Work:** Yes, if minor work not possible
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes, only if minor work cannot be performed • FDA=Tree/Vine / Overgrown / Remove • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)	**Write EC Form:** Yes, only if minor work cannot be performed • At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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6. Down Guy Marker Missing/Damaged

General Guidance: For poles installed **after 1996,** Guy Markers are required on **all** down guys. The markers must be a minimum 8 ft. in length. For poles installed ***prior to 1996,*** guy markers are **only required** on poles which are exposed to traffic. **Inspector should confirm the age of the pole via the date nail to verify the requirement.**

Install a single guy marker on multiple guys which are clamped together. For guys that are not clamped together, but on the same anchor, consider separate guy markers on each guy if the separation is large.

Note: Installing yellow colored guy marker does not negate the need to install visibility strips on the markers. Install visibility strips around traffic areas, on state highways, near curbs, driveways, etc. See visibility strip entry for more details.

Note: Install a segment of guy marker above cattle guards to ensure a minimum 8 ft. of guarding.

Minor Work: Yes

Related Documents: 06542, 022178, 99-34

GUY MARKER MISSING	CATTLE GUARD LESS THAN 8 FT
	
At this Location: Guy marker missing	**At this Location:** Cattle guard is less than 8 feet in length
Perform Minor Work: Yes, install new guy marker	**Perform Minor Work:** Yes, lower cattle guard and add guy marker to meet 8 feet requirement.
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: No, perform minor work	**Write EC Form:** No, perform minor work

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DOWN GUY: MARKER NOT REQUIRED	
 **At this Location:** Acceptable down guy attached to building, no marker required.	 **At this Location:** Acceptable down guy in marsh, no marker required.

Idle Facilities

1. Identifying and Documenting Idle Facilities

PS&R inspectors continue to identify and document idle lines as they would for any other field condition found, per the requirements and procedures in the Electric Distribution Preventative Maintenance (EDPM) Manual.

If idle lines are documented on hard copies (paper) rather than with PS&R mobile devices, PS&R inspectors update the Daily Log as follows:

- Create a new numbered entry.
- Write “IF” in the “Notification Type” column
- Include any applicable notes in the “Note” column.
- Create one IF Notification (TD-2459S-F01) for each section of idle line.

  Example: If there is an idle line with five poles, only one IF Notification is required for the entire section of line. ***Do not create an IF Notification for each pole.***

At a **minimum**, attach the following two attachments to each IF Notification:

- Photo of the field condition
- Map with the idle area clearly identified

Do not initiate an IF Notification or an EC Notification when **attachments to poles** (cross-arms, miscellaneous hardware, brackets, insulators, etc.) do not pose a safety or reliability risk to an idle facility.

Continue to document safety or reliability issues that meet criteria for vegetation notifications.

NOTE: Vegetation management personnel **do not** patrol or maintain vegetation on de-energized tap lines.

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Identify specific field conditions on Page 1 of the IF Notification. (The PS&R supervisor refers to these field conditions to prioritize the IF Notification.)

- The service planning due date (SPDD) on the IF Notification is specific to the investigation only and is the date that the investigation must be completed.
- For a list of field conditions and related QCR actions, refer to Table 1, "IF Field Conditions and Investigations Priorities," below.

NOTE: QCRs use IF Notifications to document potentially idle facilities. Customer service delivery (CSD) personnel use IF Notifications to investigate, classify, and document idle facility investigation results.

Table 1. IF Field Conditions and Investigation Priorities

Condition	Action	Investigation Priority
Safety Situation/Risk	• Mitigate hazard and make safe, which may include de-energizing. • Initiate an IF Notification for investigation. • Initiate an Electric Corrective (EC) Notification to document any other abnormal conditions to resolve.	**High** Submit to supervisor by end of day. Enter in SAP, and communicate to service planning personnel within 2 business days.
Idle transformers that do not have a blue sticker indicating a polychlorinated biphenyl (PCB) content of less that 5 parts per million (ppm) may be classified as High, Medium, or Low priority. Consider current field conditions, the transformer condition, and if the following sensitive locations are nearby: • Surface or ground waters • Sewers or sewage treatment systems • Private or public drinking water sources or distribution systems • Grazing lands • Vegetable gardens or agricultural areas • Daycare centers and schools	• If High priority, mitigate hazard and make safe, which may include de-energizing. • Initiate an IF Notification for investigation; priority is dependent upon field and equipment conditions. • Note the specific field conditions, transformer condition, and transform locations (see "Condition" column notes) in the Comments section.	**High – Medium-Low** To designate as High priority, consider the identified idle transformer locations, current condition of the transformer (see "Condition" column notes), and current condition of associated facilities (pole, crossarm, etc.)
Future work required to maintain existing idle facility (EC Notifications to repair/replace/relocate facilities).	• Initiate an IF Notification for investigation. • The IF priority depends on the due date of the EC.	**High – Medium-Low**
PG&E and Modesto Irrigation District (MID) service areas.	• Initiate an IF Notification for investigation.	**Medium**
Idle facilities in raptor concentration zones (RCZs) with suitable habitat to support threatened or endangered raptors.	• Initiate an IF Notification for investigation. • Initiate a Priority E, 3-month EC Notification to de-energize the facility.	**Medium – Low**
Oil-filled equipment considerations: • Surface or ground waters • Sewers or sewage treatment systems • Private or public drinking water sources or distribution systems • Grazing lands • Vegetable gardens or agricultural areas • Daycare centers and schools	• Initiate an IF Notification for investigation. • For idle transformers, note the absense or presence of a blue sticker on the IF Notification. • A blue sticker indicates a PCB content of less than 5 ppm.	**Medium**
Potential use for agricultural pumps or vacant buildings.	• Initiage an IF Notification for investigation.	**Low**
Entire primary tap is identificed as idle and is unfused. No future work is required to maintain the existing idle facility.	• Initiate an IF Nofication for investigation. • Initiate a Prioirty E, 3-month EC Notification to de-energize the line.	**Low**

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Identify idle facilities in RCZs.

Determine whether there is any potential use for agricultural pumps and/or vacant buildings.

Classify facilities that are to remain in the field as follows:

- De-Energized – Temporary Out of Service (TOS):
- Potential agricultural pump – TOS-AG
- Vacant building use – TOS-V

Energized – Temporary Idle Facility (TIF):

- Potential agricultural pump – TIF-AG
- Vacant building use – TIF-V

The following Table 2 is a complete listing of TOS/TIF classifications.

Table 2. TOS/TIF Classifications

Temporary Out of Service (TOS) De-Energized Temporary Idle Facility (TIF) Energized		
Facilities with a future use are grouped into one of the following classifications:		
TOS-AG	Potential agricultural use	De-energized
TIF-AG	Potential agricultural use	Energized
TOS-V	Potential service to an existing vacant building	De-energized
TIF-V	Potential service to an existing vacant building	Energized
TOS-CAP	Potential PG&E use for capacity or reliability	De-energized
TIF-CAP	Potential PG&E use for capacity or reliability	Energized
TOS-F	Future customer use identified by service planning	De-energized
TIF-F	Future customer use identified by service planning	Energized
TOS-MLX	Current Main Line Extension Agreement	De-energized
TIF-MLX	Current Main Line Extension Agreement	Energized
TOS-SFA	Current Special Facilities Agreement	De-energized
TIF-SFA	Current Special Facilities Agreement	Energized

When pending maintenance is identified on idle facilities, write a minimum of two notifications:

- One IF Notification (TD-2459S-F01) for the entire idle line
- One EC Notification per location requiring maintenance

After identifying pending maintenance on idle facilities, ensure that the IF Notification has the Field Condition box, "Future work required to maintain existing idle facility," checked. See Figure 1 below.

- Enter the following note in the EC Notification comments section: "IDLE notification created."
- Enter a note in both IF Notification and EC Notification comments with corresponding notification numbers, when available.

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Figure 1

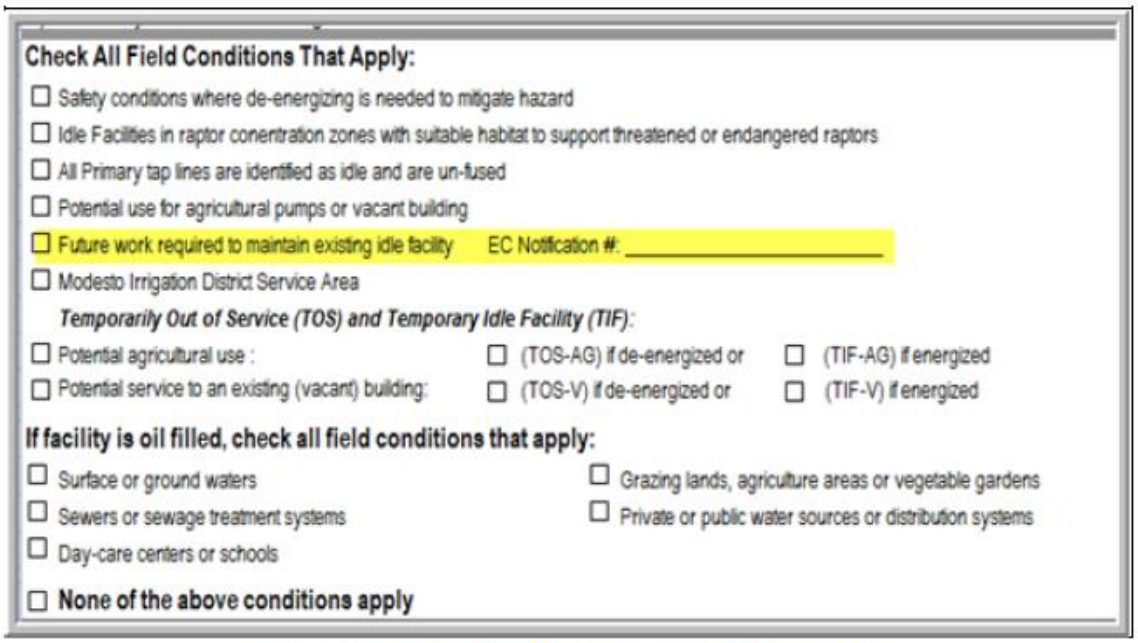


Figure 1. IF Notification – Future Work Required Field Condition and EC Notification Number

2. Energized Electric Line Facility No Longer Used to Serve Customer Load

General Guidance: It may be necessary to de-energize the idle facility:

If primary lines are energized, de-energize line sections by opening cut-outs. In raptor concentration zones (RCZs) or if the primary tap line is unfused, create a Priority E, 3-month Electric Corrective (EC) Notification to de-energize the jumpers.

> **NOTE**
>
> When idle transformers or sections of line de-energized by cut-outs are located in non-raptor areas, an EC Notification is **not** required to de-energize the jumpers.

Do not initiate an IF Notification or an EC Notification when attachments to poles (cross-arms, miscellaneous hardware, brackets, insulators, etc.) do not pose a safety or reliability risk to an idle facility. If it is not necessary to de-energize the idle facility, create a Priority “F” EC Notification.

Continue to document safety or reliability issues that meet criteria for vegetation notifications.

Minor Work: No

EC Form: Yes, to de-energize

- FDA: OH Facility Idle De-Energize
- Select the Priority “E”
- Select the 0-3 month Due Date

Idle Facility Form: Yes

Related Documents: TD-2459P-01

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3. De-Energized Electric Line Facility Already Identified on a Pending EC Notification but Not Mapped

General Guidance: Create a map change request if the facility is not mapped as idle.

Minor Work: No

Map Correction: Yes

Related Documents: TD-2459P-01

Insulators

1. Arcing or Tracking on Insulators

General Guidance: If there is evidence of arcing or tracking on a primary insulator, call the M&C supervisor, create Emergency tag, and follow emergency EC processes.

Minor Work: No

EC Form: Yes, create an Emergency EC Notification

Related Documents: Utility S2405

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2. Damaged Insulators

General Guidance: Replace all LAPP insulators and/or all glass/porcelain insulators. (LAPP insulators are porcelain.)

Replace ALL insulators if chipped, cracked, contaminated, broken, or damaged. If the crossarm is wood, replace all insulators AND crossarm w/composite crossarm.

If an insulator is damaged due to gunshot, replace with epoxy of polymer insulators.

Minor Work: No

EC Form: Yes

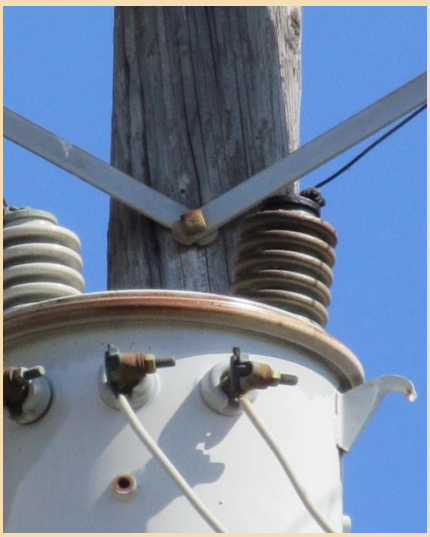
- FDA: Insulator Broken Replace
- Cannot mix insulator types. Always replace full set of insulators AND replace crossarm w/composite crossarm.
- Select the Priority and Due Date based upon Compelling Abnormal Conditions

Related Documents: 022088, TD-2305M-JA_07 Crossarm Evaluation job aid

DAMAGED INSULATOR	INSULATOR LAYING ON ITS SIDE / PRIMARY ON THE ARM
	
At this Location: Damaged insulator	**At this Location:** Insulator lying on its side. Primary on the arm.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Insulator / Broken/ Damage / Replace • Priority ”E”, 3-12 months depending upon exposure	**Write EC Form:** Yes • FDA=Insulator / Broken/ Damage/ Replace • Priority ”A”, follow Emergency Process

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FLASHED INSULATOR ON TRANSFORMER



At this Location: Flashed image on transformer

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA= Transformer / Flashed / Replace
- Priority ”E”, 3-12 months depending upon exposure

BROKEN WOOD PIN ON PRIMARY



At this Location: Broken wood pin. Primary (High Voltage Sign). Conductor on arm.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Insulator / Squatter-(Primary) / Replace
- Priority ”A”, follow Emergency Process, (Conductor contacting crossarm)

FLASHED INSULATOR POTHEAD



At this Location: Flashed pothead

Perform Minor Work: No

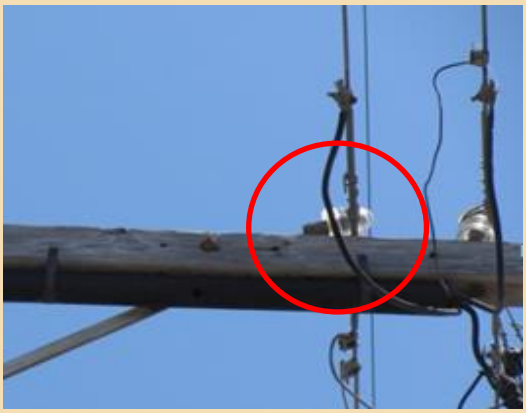
Write Third-Party Notification: No

Write EC Form: Yes or COE (pin or energized)

- FDA=Riser/Pothead / Flashed / Replace
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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BROKEN WOOD PIN ON SECONDARY



At this Location: Broken secondary wood pin. Conductor lying on the arm, tangent pole. (excluding urban wildfire areas, use risk priority matrix)

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: Yes, if minor work not possible

- FDA= Insulator / Squatter (Secondary) / Replace
- Priority ”B”, 0-3 months depending upon exposure

BROKEN SECONDARY INSULATOR



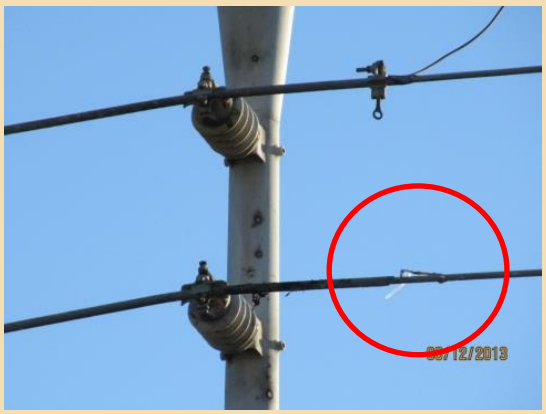
At this Location: Broken secondary insulator, double crossarm that has acceptable secondary insulator

Perform Minor Work: Yes, replace secondary insulator

Write Third-Party Notification: No

Write EC Form: No

FLASHED INSULATOR MYLAR BALLOON



At this Location: Flashed insulator by Mylar balloon

Perform Minor Work: No

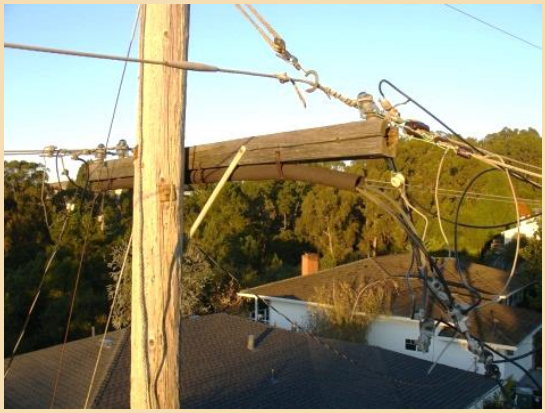
Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Insulator / Flashed / Replace
- Priority ”E”, 3-12 months depending upon exposure

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ACCEPTABLE TEMPORARY REPAIRS



Deteriorated Crossarm



Close-up

At this Location: Acceptable temporary repairs made by Troubleman. Crossarm deteriorated, temporary repair to stabilize secondary conductor. Pending EC Notification.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Crossarm / Broken/Damaged / Replace
- Priority ”E”, 3-12 months depending upon exposure

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3. Squatters

General Guidance: Create an EC Notification at a **maximum** Priority “E” for **all primary and secondary** squatters.

Minor Work: NO

EC Form: Yes

- FDA = Crossarm Decayed/Rotten / Replace or
- FDA = Insulator / Primary Squatter / Replace
- Note: When replacing insulators, do NOT mistmatch insulators. ALWAYS include crossarm replacement (replace with composite arm) on primary and secondary squatter EC notifications with wood crossarms.

Related Documents: 022088, Crossarm Evaluation TD-2305M-JA_07

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PRIMARY SQUATTER	
	**At this Location:** 2 Primary Wood Pin Squatters; replace wood crossarm with composite crossarm.. **Perform Minor Work:** No **Write Third-Party Notification:** No **Write EC Form:** Yes • FDA = Crossarm Decayed/Rotten / Replace or FDA = Insulator / Primary Squatter / Replace • At minimum – must write up as Priority ”E”, based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, or E)

SECONDARY SQUATTER AND DECAYED CROSSARM	
	**At this Location:** Secondary Squatter and decayed crossarm. **Perform Minor Work:** No **Write Third-Party Notification:** No **Write EC Form:** Yes • FDA= Crossarm / Decayed/Rotten / Replace • Priority ”E”, 3-12 months depending upon exposure • Note: When replacing insulators, do NOT mistmatch insulators.

4. Flying Bells

General Guidance: Identify every location where flying bells are installed. Note the type of insulator (ceramic or non-ceramic).

Minor Work: No

EC Form: Yes if broken or damaged.

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Lightning Surge Arresters

1. Flashed/Blown

General Guidance:

Replace if the lightning arresters are already cut in the clear.

IF a damaged lightning/surge arresters is compelling, THEN create an EC Form

Minor Work: No

EC Form: Yes

- FDA: Lightning / Arrestor Broken/Damaged / Replace or Lightning Arrestor /Flashed / Replace
- Select the Priority and Due Date based the 'Probability & Impact Chart' and exposure risks

Related Documents: 031822

Markings

1. High Voltage Sign Not Installed as Required

General Guidance: Inspectors are required to look for missing or broken high voltage signs during inspections. If inspectors find missing or broken signs, they should install new signs as minor work if they have the appropriate materials and equipment, and can perform the work safely. If the inspector cannot install a sign as minor work, the inspector must create a Priority 'F' EC notification. Below is guidance on how to evaluate high voltage signage.

High Voltage Sign Requirements:

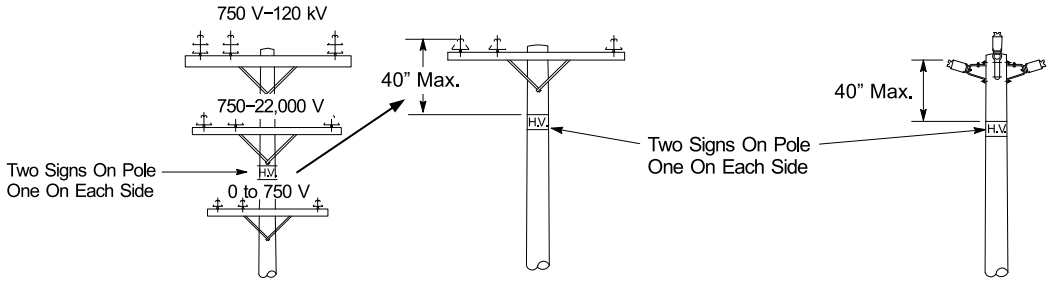
Poles that support line conductors or risers energized at **more than 750 volts** must be marked with high voltage signs. **IMPORTANT: If a pole is marked under any of the options below, it satisfies the high-voltage marking requirement.** When installing new high voltage signs using one option, inspectors are not required to remove signs previously installed under different options.

Marking Options:

A. **Sign the Pole Below the Lowest 750V+ Line Conductor (Preferred Method)**

Marking requirements are satisfied under this option if:

1. There are two signs, attached to the surface of each side of the pole[1].
2. The top of each sign is no more than 40'' below the lowest level line conductor that exceeds 750V.



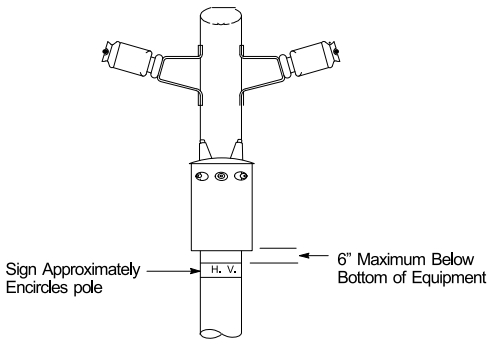
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[1] **Exception:** If an inspector finds only one high-voltage sign within 40'' below the lowest 750V or greater conductor, the inspector **is not required to install a second sign**. However, when performing work at the lowest crossarm level, a second sign must be installed.

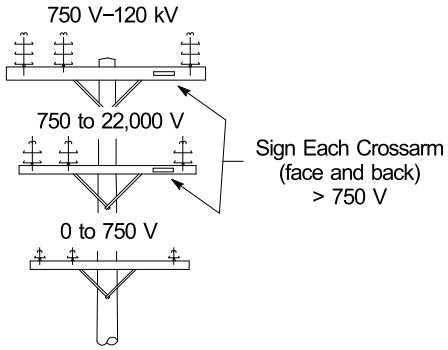
B. Sign the Pole Below Equipment
Marking requirements are satisfied under this option **if:**

1. There are two signs attached to the surface of each side of the pole2.
2. The top of each sign is no more than 6'' below the equipment.
3. The signs are above all 0-750V supply and communication line conductors.

[2] **Exception:** If an inspector finds only one high-voltage sign installed within 6'' below the equipment, the inspector **is not required to install a second sign**. However, when performing work at the equipment level, a second sign must be installed.



C. Sign Each Crossarm
Marking requirements are satisfied under this option **if:**
1. Each crossarm (line arm) supporting line conductors in excess of 750V are signed both front and back. Signs are not required on the inside faces of double arms.



The exceptions in Sections A and B do not apply when, in the judgment of the inspector, the two high voltage signs should be installed so that they may be visible from all sides of the pole. Typical examples are poles near water areas suitable for sailboats, near established boat ramps and associated rigging areas, adjacent to swimming pools, and in agricultural areas with moveable irrigation piping.

Minor Work: Yes

Related Documents: None

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2. Operating Number Incorrect / Illegible/ Missing

General Guidance:

IF the operating number on the field equipment does **not** match the operating number printed on inspection map;

THEN (1) **contact the local Distribution Operation (DO)** to confirm the discrepancy and to get further instructions

(2) DO confirms the field equipment number is **correct;** then complete a **map correction**

(3) DO confirms the field equipment number is **not correct**; then **perform minor work to correct the operating numbers** on the field equipment

(4) DO **cannot confirm the operating number**; then get a PIN from DO and complete a **map correction** to get an operating number assigned

(5) DO confirms the field equipment number for equipment in the field that **does NOT** have a field equipment number installed; then **complete minor work to install the equipment number OR create an EC** to have M&C install the field equipment number

Note: Alpha characters may differ between divisions. Be sure to confirm the "number" with the local DO and PS&R Supervisor.

Operating number should be installed in the operating position; if missing, they should be installed on the operating position, not at the 6' level. Consider also adding the # at the 6' level for ease of identification for field EE's.

If operating number exists, is it legible (faded, etc.); if not legible replace them as minor work.

If operating number is not installed in the field, but on the inspection map - call the DO to confirm the correct number before installing.

If confirmed that the field is wrong, correct as minor work.

If confirmed that the operating number is mapped but not installed in the field, install the operating number as minor work.

If operating number is not installed in the field, but on the inspection map and/or in GIS - call the team lead who will contact the DO to confirm the correct number before installing.

If confirmed that the number is mapped but not installed in the field, or the field is incorrect, correct as minor work if possible, or write EC notification.

Write EC for exempt/non-exempt clearing around pole.

For non-exempt equipment locations with VMS tagging: Write vegetation tag if clearing around pole is needed.

Minor Work: Yes

Map Correction: Yes, if operating number needs to be corrected

EC Form: Yes, if you cannot perform minor work

- FDA: Marking / Broken/Damaged / Replace or Marking / Missing / Install
- Select the Priority and Due Date based upon Compelling Abnormal Conditions

Related Documents: 057352

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FADED OPERATING NUMBER



Before: Faded operating number



Close-up



After: Minor work completed, operating number applied below operating position.

At this Location: Operating number is faded

Perform Minor Work: Yes

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Marking / Broken/Damaged / Replace
- At minimum – must write up as Priority ”F-R”, next inspection cycle; based on field condition and exposure, corrosion, etc.; prioritize as needed (A, B, E, or F)

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3. Damaged or Missing Visibility Strips on Poles/Guy Markers

General Guidance: Reflective visibility strips shall be installed on wood, fiberglass, or steel poles, streetlight poles, and guy markers as follows:

A. On poles and guy markers installed on state highways.

B. On poles and guy markers located within 15 feet from the paved surface or 15 feet from the edge of the traveled, unpaved portion of city or county roads (streets) where not protected by curbs.

C. On poles and guy markers within 6 feet of an adjacent driveway, private roadway (street), turnaround, parking lot, or thoroughfare in rural district, capable of being traversed by vehicles, where these are not protected by curbs.

Notes:

Visibility strips are not required on poles or guy markers behind a curb, approximately 5-1/2” x 5-1/2” and 90 degrees to the surface.

Visibility strips should not be installed if there is no reasonable expectation of traffic. For example: Cross country poles, poles through waterways or wetlands, rear easements poles, poles behind guardrails, or poles on embankments that are well above or below the road.

Reminders:

- Do not install visibility strips on top of the old one. Inspectors must remove the old strip first.
- If the old strip is in good condition, but became loose, re-secure the strip to the structure.
- Do not install metal visibility strips over any vertical molding/riser.
- If any visibility strip work is required, bring the location up to the current visibility strip standard (all must be the same color – yellow)
- Install visibility strips on the side facing oncoming traffic when known.
- Do not install visibility strips within 1-1/2” of U-shaped molding

Minor Work: Yes

Related Documents: 022168, GO 95 Rule 56.9 (1964, 1990, 1996 Change to Guy Marker)

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ADHESIVE VISIBILITY STRIPS



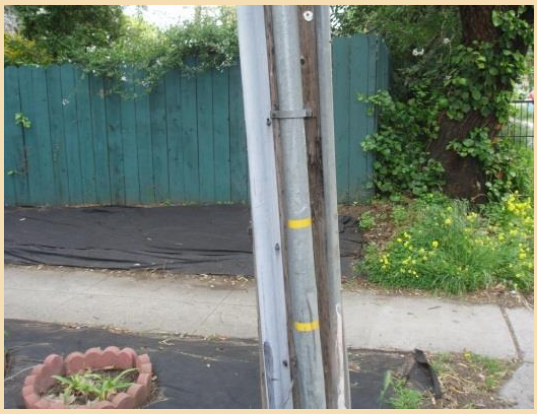
At this Location: Acceptable application of plastic and adhesive visibility strips

CLEARANCE FROM GROUND



At this Location: Acceptable metal visibility strips attached 1 ½“from ground.

INADEQUATE VISIBILITY STRIPS



At this Location: Pole with vehicular exposure. Two small sections of yellow adhesive visibility strips.

Perform Minor Work:

Yes, apply 3 adhesive visibility strips on the pipe.

Yes, apply 3 adhesive visibility strips to the plastic molding.

Write Third-Party Notification: No

Write EC Form: No, perform minor work

VISIBILITY STRIPS PAINTED OVER NO LONGER REFLECTIVE



At this Location: Visibility strips painted brown (3rd visibility strip located above not shown in picture)

Perform Minor Work: Yes, remove old visibility strips and install new.

Write Third-Party Notification: No

Write EC Form: No, perform minor work

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METAL OVER MOLDING



Before



After

At this Location: Metal visibility strips under wood molding and over wood molding with protruding edge.

Perform Minor Work: Yes, remove old metal visibility strips and apply new visibility strips; **visibility strips on after photo are fiber, not metal** (coded item)

Write Third-Party Notification: No

Write EC Form: No, perform minor work

OLD METHOD VISIBILITY STRIPS



At this Location: Aged visibility strips have lost reflectivity.

Perform Minor Work: Yes, replace with 3 yellow visibility strips

Write Third-Party Notification: No

Write EC Form: No, perform minor work

OLD AND NEW VISIBILITY STRIPS



At this Location: Yellow visibility strips mounted over old white visibility strips.

Perform Minor Work: Yes, remove old visibility strips

Write Third-Party Notification: No

Write EC Form: No, perform minor work

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Oil-filled Equipment

1. Equipment Oil: Leaking/Weeping Stain

General Guidance: Refer to the EDPM Manual - Assessments and Notifications Section for additional information about addressing oil in the field.

IF you observe a **stain or leak**

THEN (1) Look for **exposure or contamination**

Refer to the PCB Spill/Leak Category Response Matrix in order to determine the appropriate action:

PCB Spill/Leak Category Response Matrix
Overhead & Sub-surface Equipment

Indicator	PCB Equipment Manufactured Before July 1979		Non-PCB Equipment Manufactured July 1979 or later	
	EC Notification Priority	Standby at Site	EC Notification Priority	Standby at Site
Equipment has failed and insulating fluid has run off the surface of the equipment and is in contact with the soil, vegetation, or water.	A Replace	Yes	A Replace	Yes
Insulating fluid has run off the surface of the equipment and is in contact with the soil, vegetation, or water OR Insulating fluid is actively dripping.	A Replace	Yes	A Replace	Supervisor discusses with EFS to determine need to standby based on location and size of spill.
Insulating fluid is about to run off the surface of the equipment but has not made contact with the soil, vegetation, water, or structure.	A Replace	Yes	A Replace	Supervisor discusses with EFS to determine need to standby based on location and size of spill.

PCB Spill/Leak Category Response Matrix
Overhead & Sub-surface Equipment
(Continued)

Indicator	PCB Equipment Manufactured Before July 1979		Non-PCB Equipment Manufactured July 1979 or later	
	EC Notification Priority	Standby at Site	EC Notification Priority	Standby at Site
Insulating fluid is on the surface of the equipment and is **not** about to run off the surface and has **sheen** (Weeps or Seeps).	Supervisor discusses with EFS to determine EC notification category based on sensitivity of location and upcoming weather. IF no timely response from EFS within ½ hour, THEN assumed to be sensitive area.			
Sensitive Areas	A Replace	Not needed	B 3 month Recheck • Describe sheen in notification • Re-check in 3 months.	Not needed
Non-sensitive Areas	B 30 day Replace IF estimating cannot be completed in time to meet 30 day deadline, THEN replace with like.			
Residual stain is a mark on the equipment that appears dried. Examples: • Stain on side of overhead transformer • Stain on concrete	No further action needed	Not needed	No further action needed	Not needed

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PCB Spill/Leak Category Response Matrix, continued

PCB Spill/Leak Category Response Matrix
Padmount Equipment

Indicator	PCB Equipment Manufactured Before July 1979 2		Non-PCB Equipment Manufactured July 1979 or later	
	EC Notification Priority	Standby at Site	EC Notification Priority	Standby at Site
Equipment has failed and insulating fluid has run off the surface of the equipment and is in contact with the soil, vegetation, or water.	A Replace	Yes	A Replace	Supervisor discusses with EFS to determine need to standby based on location and size of spill.
Insulating fluid Is actively dripping either outside or inside the cabinet doors.	A Replace	Yes	A Contain & Clean Complete cleaning A, B, or E Replace	Supervisor discusses with EFS to determine need to standby based on location and size of spill.

Minor Work: No

Related Documents: TD-2320P-01 Attachment 4,TD-2305M-JA_05 Corrosion Evaluation

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2. Corrosion

General Guidance: In many parts of PGE's service territory, facilities are exposed to conditions that both cause and accelerate corrosion of metal components.

During detailed inspections, examine facilities and assess their condition. If corrosion is minor, repairs to the protective coatings that cover the metal surfaces on the equipment should be made. In addition, during the diagnostic testing for specific types of distribution line equipment, perform an examination for corrosion.

Minor Work: Yes

EC Form: Yes, if compelling

- Select the appropriate FDA
- Select the Priority and Due Date based the 'Probability & Impact Chart' and exposure risks

Related Documents: TD-2305M-JA_05 "Corrosion Evaluation Job Aid", G12020

IF you observe corrosion

THEN (1) Look for exposure

(2) Refer to the below table for to determine the corrosion rating and the required actions to perform. Visual examples follow:

Description	Symptoms	Required Actions
Integrity is breached	Hole(s) in metal (public exposure to high voltage, cover not securable, significant oil leak or spill, etc.)	EC notification Priority A – replace immediately or make safe and issue Priority B – replace/repair
Metal is damaged	Separation, layering, bubbling	EC notification Priority E – replace/repair Not to exceed 12 months
Moderate to heavy corrosion	No sign of metal degradation	Inspect at next interval Pad-mounted equipment – clean and paint
Little or no corrosion	Discolored paint, staining	No action required

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OH CORROSION EXAMPLES



At this Location: Corrosion Weakening Integrity of Tank

Metal is separating into layers

Corrosion will breach tank

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form:

- FDA=Transformer Leaks/Seeps/Weeps Replace
- Priority ”E”, 3-12 months depending upon exposure



At this Location: Transformer with moderate/heavy corrosion

Metal structure still sound (rust staining from attachments)

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: No

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TRANSFORMER WITH STAINING, NO CORROSION	TRANSFORMER CASE WITH LITTLE OR NO CORROSION
	
At this Location: Transformer with dirt and salt spray staining, no metal damage	**At this Location:** Transformer with little to no corrosion, no metal damage
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: No	**Write EC Form:** No

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Poles

1. Solely-Owned Poles with Third-Party Attachments

General Guidance: Identify all solely owned pole with third-party attachments (based on how it is mapped). Write EC Notification for Pole / Overloaded / Test, for Estimating to confirm pole loading.

Determine if additional clearing is needed for access to pole; if so - write EC Notification.

Minor Work: Yes, create an EC Notification to clear vegetation unless it can be addressed as minor work

Related Documents: EDPM Pole Inspection, Utility S2325

2. Broken Poles

General Guidance: Observations in the field may include:

1. Broken
2. Split
3. Decayed / Rotten
4. Vandalized
5. Any pole deformity
6. Any condition that may impair conductor clearance
7. Cracked poles: assess for potential failure



An ‘N’ tag indicates previously identified damaged pole.

If pole has reduced circumference. Write EC Notification for Pole / Overloaded / Test, for Estimating to confirm pole loading.

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Minor Work: No

Related Documents: EDPM Pole Inspection, Utility S2325

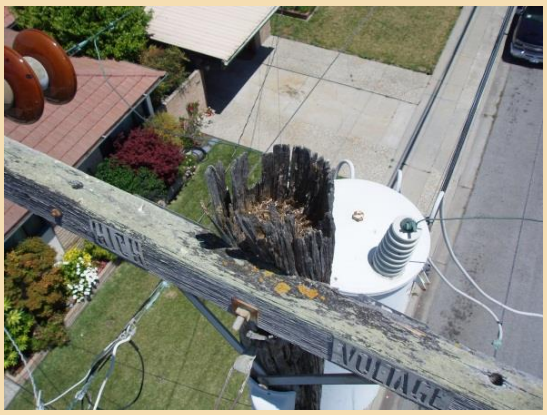
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POLE BROKEN AT THE COMMUNICATION LEVEL	POLE BROKEN AT MIDDLE SECTION
	
At this Location: Pole broken at the communication level in rural location. Complete Pole Inspection Test Report	**At this Location:** Broken pole. Complete Pole Inspection Test Report
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Pole / Broken/Damaged / Replace • Priority ”B”, 0-3 months depending upon exposure	**Write EC Form:** Yes • FDA=Pole / Broken/Damaged / Replace • Priority ”E”, 3-12 months depending upon exposure

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BROKEN POLE	POLE SPLIT AT COMMUNICATION LEVEL
	
At this Location: Broken pole. Complete the Pole Inspection Test Report. Pole supported in four directions.	**At this Location:** Pole split at communication level. Complete the Pole Inspection Test Report.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Pole / Broken/Damaged / Replace • Priority ”B”, 0-3 months depending upon exposure	**Write EC Form:** Yes • FDA=Pole / Broken/Damaged/ Replace • Priority ”E”, 3-12 months depending upon exposure

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DAMAGE TO POLE FROM SPECIFIC EVENT	DECAY OF POLE OVER TIME
	
At this Location: Pole burnt If pole has reduced circumference. Write EC Notification for Pole / Overloaded / Test, for Estimating to confirm pole loading.	**At this Location:** Pole top decayed. Entire pole failed pole test. Complete the Pole Inspection Test Report. If pole has reduced circumference. Write EC Notification for Pole / Overloaded / Test, for Estimating to confirm pole loading.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form Yes, Write EC Notification for Pole / Overloaded / Test, for Estimating to confirm pole loading.	**Write EC Form:** Yes • FDA=Pole Decayed/Rotten/Replace • Priority ”E”, 3-12 months depending upon exposure

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SAW CUT INTO POLE



At this Location: Vandalized pole. Chain saw cut into lower portion of pole. Half of pole circumference cut into.

Notify supervisor of possible vandalism. Supervisor will have to communicate to damage claims. Complete Poles Inspection Test Report.

If pole has reduced circumference. Write EC Notification for Pole / Overloaded / Test, for Estimating to confirm pole loading.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Pole / Broken/Damaged/ Replace
- Priority ”E”, 3-12 months depending upon exposure



At this Location: Vandalized pole. Chain saw cut into lower portion of pole. More than half of pole circumference cut into.

Notify supervisor of possible vandalism. Supervisor will have to communicate to damage claims. Complete Poles Inspection Test Report.

If pole has reduced circumference. Write EC Notification for Pole / Overloaded / Test, for Estimating to confirm pole loading.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Pole / Broken/Damaged / Replace
- Priority ”B”, 0-3 months depending upon exposure

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POLE DAMAGED ON THE BOTTOM BUT OK



At this Location: Pole damaged by vehicle. Splint installed as temporary repair. Inspection shows adequate circumference/strength. Sharp ragged splinters. Curb is adequate protection – visibility strips not required.

Write EC Notification for Pole / Overloaded / Test, for Estimating to confirm pole loading.

Perform Minor Work: Yes, Remove sharp edges, remove splint.

Write Third-Party Notification: No

Write EC Form: Yes.

- FDA= Pole / Overloaded / Test

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DETERIORATION AROUND GROUND LINE



Before extraction



After extraction showing below ground deterioration

At this Location: Deteriorated condition found during normal inspection. Complete Pole Inspection Test Report. If pole has reduced circumference. Write EC Notification for Pole / Overloaded / Test, for Estimating to confirm pole loading.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Pole / Decayed/Rotten / Replace
- Priority ”A”, follow Emergency Process

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3. Leaning Pole

General Guidance: Consider the following when evaluating a leaning pole:

- Is the pole out of plumb by more than 10% of its height above the ground?
- Is the leaning pole causing excessive conductor sag or reduced clearance issues that could result in contact, fire risk, or public safety?
- Does the lean appear as if it will become worse or affect safety or reliability in the next 5 years (considering environmental and configuration factors -soil, wind, pole attachments, equipment, guying)?

If the answer is **yes** to any of these questions, and in the inspector's judgment the pole is leaning excessively, **write an EC Notification (Pole / Leaning / Replace) and fill out Pole Test Data Sheet**.

Note: If the Inspector suspects that a third party attachment is causing the pole to lean, consider writing a Third Party Utility notification vs. an EC Form.

Minor Work: No

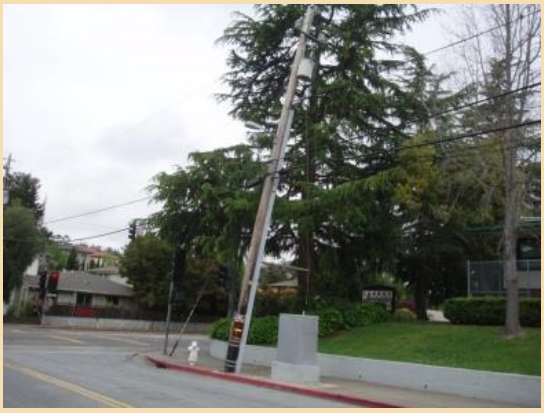
Related Documents: 023058

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LEANING POLE	LEANING SLACK SPAN
	
At this Location: Leaning pole greater than 10% out of plumb. Pole is stable. No equipment in rural area. Causing reduced clearance.	**At this Location:** Leaning pole more than 10% out of plumb. Pole test indicates that pole is solid below ground and can be staightened. Probability of equipment failure is moderate.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Pole / Leaning / Replace • Priority ”E”, maximum12 months	**Write EC Form:** Yes • FDA=Pole / Leaning / Adjust • Priority ”E”, 3-12 months depending upon exposure

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STUBBED POLE LEANING TOWARDS SCHOOL



At this Location: Stubbed pole leaning towards school, supported by down guy. Pole Bands are loose due to additional deterioration of the pole. Pole test data sheet indicates that pole no longer meets stubbing criteria causing reduced clearance issues

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Pole / Decay/Rotten / Replace
- Priority ”E”, 3-12 months depending upon exposure

POLE LEANING 3 POT TRANSFORMER IN BUCK POSITION



At this Location: Pole is leaning less than 10% out of plumb, leaning in direction of offset equipment. Pole inspection found pole stable.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: No

POLE LEANING NEAR RAILROAD TRACKS



At this Location: Severe lean being held up by the primary conductors. Low clearance over active railroad tracks. Pole located in a swamp area with standing water.

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Pole / Decayed/Rotten/ Replace
- Priority ”A”, follow Emergency Process

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4. Deformed Pole

General Guidance:

For deformed poles, write EC Notification for Pole / Overloaded / Test, for estimating to confirm pole loading.

If the deformity appear as if it will become worse or affect safety or reliability in the next 5 years (considering environmental and configuration factors -soil, wind, pole attachments, equipment, guying) - write EC notice to replace pole.

Common drivers for deformed poles: Improper/lack of guying, third party attachment

Review clearances to verify no reduced clearance issues, all levels of clearance requirements that could result in contact, fire risk, or public safety.

Minor Work: No

Related Documents: EDPM Pole Inspection

POLE BENT 4 FEET OUT OF LINE	INADEQUATE SUPPORT AT COMMUNICATIONS LEVEL
	
At this Location: Pole bent 4 feet out of line, less than 10% lean	**At this Location:** Two guys stabilizing communication level.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes, only when the inspector decides that further assessment is required. • FDA=Pole / Overloaded / Test • Priority ”E”, 3-12 months depending upon exposure	**Write EC Form:** Yes, only when the inspector decides that further assessment is required. • FDA=Pole / Overloaded / Test • Priority ”E”, 3-12 months depending upon exposure

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OVER STRESSED POLE	UNBALANCED LOAD AT TOP
	
At this Location: Pole is twisted, cracked, due to communication.	**At this Location:** Deformed pole with bowed top in line with conductor with no visible breaks. No compelling condition.
Perform Minor Work: No	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Pole / Overloaded / Replace Pole Test Data Sheet is Required • Priority "E", 3-12 months depending upon exposure; add in field comments "overloaded by communications."	**Write EC Form:** No

5. Soil Excessively Eroded or Washed Away at Base of Pole

General Guidance: If the inspector notices that a large amount of soil was washed or eroded away at the base of a pole, consider writing an EC Form to investigate whether the pole still meets its designed set depth.

Review clearances to verify no reduced clearance issues, all levels of clearance requirements that could result in contact, fire risk, or public safety.

Minor Work: No

Related Documents: 015203

6. Pole Steps

General Guidance: Remove any pole steps less than 8 feet 6 inches above the ground or any other accessible surface; this allows for grading, landscaping, etc.

Minor Work: Yes

Related Documents: 022616 p.2

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7. Mud sill

General Guidance: Repair/replace deteriorated mud sill. Review clearances to verify no reduced clearance issues, all levels of clearance requirements that could result in contact, fire risk, or public safety.

Minor Work: No

Related Documents: 030109

8. Transmission Poles

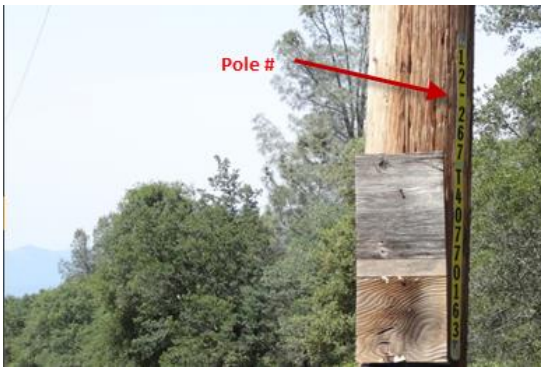
General Guidance: At minimum, when performing GO 165 patrols or inspections, Inspectors should perform a "patrol" of the transmission assets in the area being patrolled or inspected in order to identify any **obvious structural problems or hazards** that need to be addressed by the Transmission Organization. Review clearances to verify no reduced clearance issues, all levels of clearance requirements that could result in contact, fire risk, or public safety.

Examples of the types of issues that could be identified:

- Damaged or broken poles
- Broken or decayed crossarms
- Broken insulators
- Damaged tie wire
- Vegetation issues

If you identify an obvious structural problem or hazard in the field that is NOT an emergency:

- Assign a location # of your map
- *Document the location # on your P&I Daily Log
- Take a photo of the pole # on the pole; example:



- Take a **minimum** of one photo to document the issue at the location
- Refer to the Transmission key contact map to identify the **T-Line contact** for that area
- Contact the appropriate **Transmission Supervisor** (leave a VM if not available)
- In the comments section of your log entry, note the following:
  - The issue identified (i.e. bad pole, broken crossarm, etc.)
  - The transmission pole #
  - The date, name and phone number of the T-Line employee that you contacted
  - The digital photo number(s) associated with the location

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When in doubt call your Supervisor or PG&E Lead

Minor Work: No

Riser Molding

1. Broken/Missing Riser Ground

General Guidance:

See 'Ground / Ground Molding' in this job Aid

Minor Work: None

Related Documents: 027742

2. U-Shape Riser Molding Broken/Damaged or Unsecured

General Guidance – Existing Molding:

Ensure bottom section of ground molding is flush against the pole

IF molding is NOT firmly attached to pole

THEN Perform Minor Work to secure molding to pole by attaching all lags ***OR*** Create EC Notification

Address any gaps identified via minor work or write an EC notification

General Guidance if Installing New Molding or Repairing Existing Molding:

Below 8 feet: Both sides of the molding must be secured to the pole at least every 18 inches

Above 8 feet: Both sides of the molding must be secured to the pole at least every 36 inches

Minor Work: Yes

Related Documents: 021924

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SmartMeter/SCADA Equipment

1. Broken/Damaged SmartMeter Relay/Access Point/Data Collector Unit or SCADA Equipment

General Guidance: If, through visual inspection, an inspector sees broken or damaged SmartMeter antenna, DCU, or SCADA equipment, create an EC Form. Be sure to check the SmartMeter box on the EC Form. If visible, note the operating number and/or serial number of the equipment.

Supervisors will contact SmartMeter Operations to notify them of the issue.

Minor Work: No

Related Documents: 072145, 072150, 068190, SMRT-9000WBT, 054422

EXAMPLES OF SMARTMETER ON POLE









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Streetlights

1. Broken or Damaged Streetlight Pole

General Guidance: Test for out-of plumb, then write an EC Form.

Minor Work: No

Related Documents: Utility S2309

MISSING STREET LIGHT	LEANING AGGREGATE POLE
	
At this Location: Cone indicates location of missing decorative street light and pole. Exposed wire is de-energized. Include picture of similar street light for replacement.	**At this Location:** Leaning aggregate pole more than 10% out of plumb. Pole is broken at base and not stable. Light still working.
Perform Minor Work: Yes, make safe.	**Perform Minor Work:** No
Write Third-Party Notification: No	**Write Third-Party Notification:** No
Write EC Form: Yes • FDA=Streetlight / Missing / Install • Priority "B", 30 days for regular streetlights, add in field comment section if pole is missing. • Priority "E", 6 months for decorative streetlights, add in field comment section – describe if pole is missing.	**Write EC Form:** Yes • FDA=Pole / Broken/Damaged / Replace • Priority "B", 0-3 months depending upon exposure

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2. Day Burner

General Guidance: Do not create an EC Notification for a day burner. Call a clerk to contact Restoration Dispatch to get a T-Man to respond. This is to ensure correct accounting for streetlight work (depending on the rate that the customer is one, etc.).

Minor Work: Yes; if you have the materials on your truck

Related Documents: Utility S2309

3. Missing Streetlight

General Guidance: If the inspector notices that a missing streetlight, first, make safe then write an EC Form to install a missing streetlight.

Minor Work: No

Related Documents: Utility S2309

Trees

1. Trees within 4 Feet of a Primary Line

General Guidance: If you have any questions about the integrity of tree, (causing damage to our facilities, dead or dying, causing conductor height issue, etc.), write a Vegetation Notification to remove dead/dying tree. Identify all tree connects - secondary, service, guying.

Broken Limb on Conductor: Remove the limb as minor work with a hot stick if it is safe to do so.

Vegetation Touching Bare Conductor or Signs of Burning or Arcing: Create an emergency Priority “A” Vegetation Management Tag and call vegetation management for assistance. Wait at the location until relieved by Vegetation Management personnel.

Vegetation Not Touching Bare Conductor and No Signs of Burning or Arcing: Create a priority “B” Vegetation Management tag.

Minor Work: Yes

Related Documents: None

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2. Tree Attachments

General Guidance: If you have any questions about the integrity of the tree, (causing damage to our facilities, dead or dying, causing conductor height issue, etc.), an write an EC Notification to install a clearance pole.

Identify all tree connects - secondary, service, guying.

Minor Work: No

Related Documents: None

3. Trees Causing Strain or Abrasion to a Secondary Conductor or Service

General Guidance:

If vegetation is:

A. Causing damage to the conductor insulation due to friction (Note: scuffing and polishing is NOT damaged) or

B. Causing strain on the conductor that is adversely affecting other supply facilities.

Note: The inspector should clear the vegetation or move the conductor as minor work if possible. Inspectors should leave the trimmings at the location; use door hanger to notify customer.

If the inspector cannot clear the vegetation or move the conductor:

- For service drops: Create an EC notification
- For secondary conductor spans serving 2 or more customers: Write a Vegetation Management notification with priority based on severity.

Note: Vegetation Management considers secondary as conductor that feeds more than one physical address (per Rule 16); i.e. multiple “service” conductors feeding the **same customer/property are considered service**, not secondary; Inspector will need to **write an EC** in this scenario

If the inspector sees a hazardous vegetation issue on communication facilities, create a third-party notification.

Minor Work: Yes

Related Documents: None

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PHONE TREE CONDITION



At this Location: Tree putting strain on the pole, due to communication line

Perform Minor Work: No

Write Third-Party Notification: Yes

Write EC Form: No

SECONDARY HARD AGAINST TREE



SECONDARY OVERGROWN



At this Location: Secondary conductor resting on tree/vegetation

Perform Minor Work: No

Write Third-Party Notification: No

Write EC Form: Yes

- FDA=Tree / Overgrown / Trim
- FDA= Conductor / Clearance / Adjust
- Priority ”E”, 3-12 months depending upon exposure

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Wildlife Protection

1. Existing Migratory Bird Protection Damaged

General Guidance: Evaluate locations where animal mitigation has previously been installed, is not sufficient, or is missing/broken.

Note where there are signs of animal activity/nesting/debris. Write EC Notification to install animal mitigation if nest is already abandoned, etc.

Minor Work: No

Related Documents: Utility S2321, 061149

2. Existing Wildlife Protection Damaged

General Guidance: Inspector should write an EC Form to repair/replace existing wildlife protection installed in the field (cow guards, etc.)

Identify any missing animal guards on all overhead transformers. Document locations that do not have bushing covers and insulated jumpers

Identify all locations with bushing mounted cutouts.

Note where there are signs of animal activity/nesting/debris. Write EC Notification to install animal mitigation if nest is already abandoned, etc.

Minor Work: No

Related Documents: 061149

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Clearance Evaluation Job Aid

TD-2305M-JA12
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Overhead Clearance Evaluation

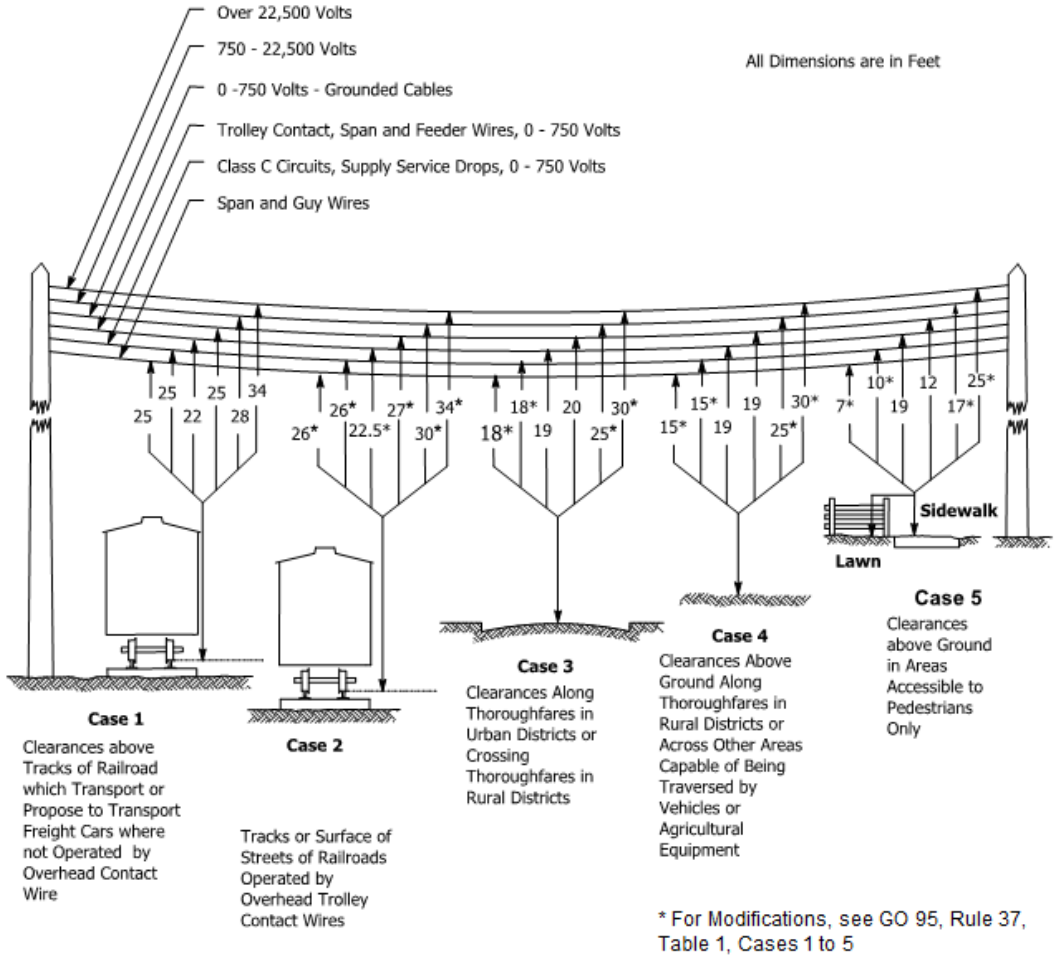
Guidance Document References:
TD-2305M – EDPM 2011 Manual
Engineering Document 022158 – Clearance Tables CPUC General Order 95

Level of Use:
- ❑ Information
- ✓ Reference
- ❑ Continuous

General Information

This job aid contains reference material to help compliance inspectors evaluate conductor clearance issues they visually identify in the field.

Ground Clearances - General

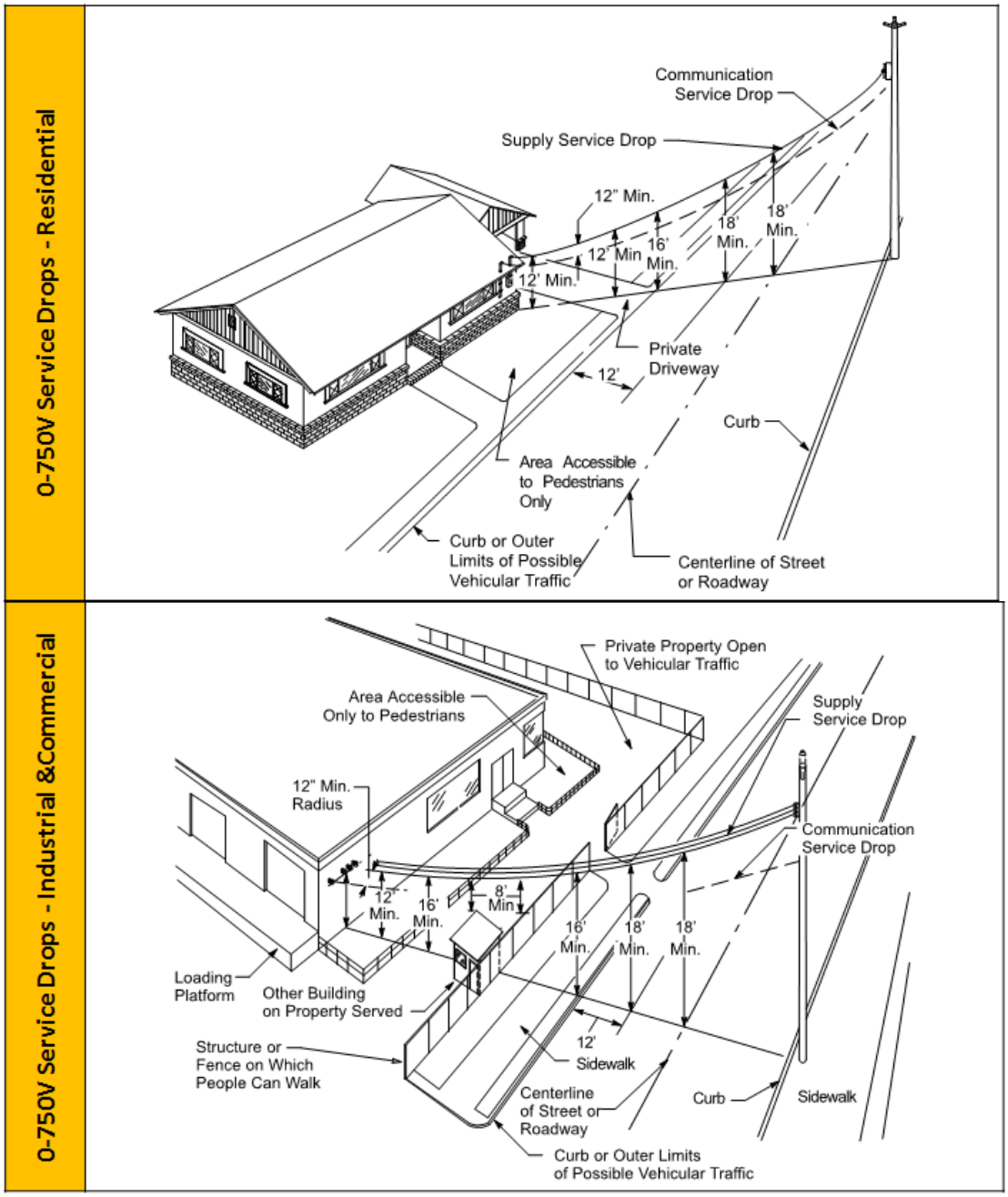


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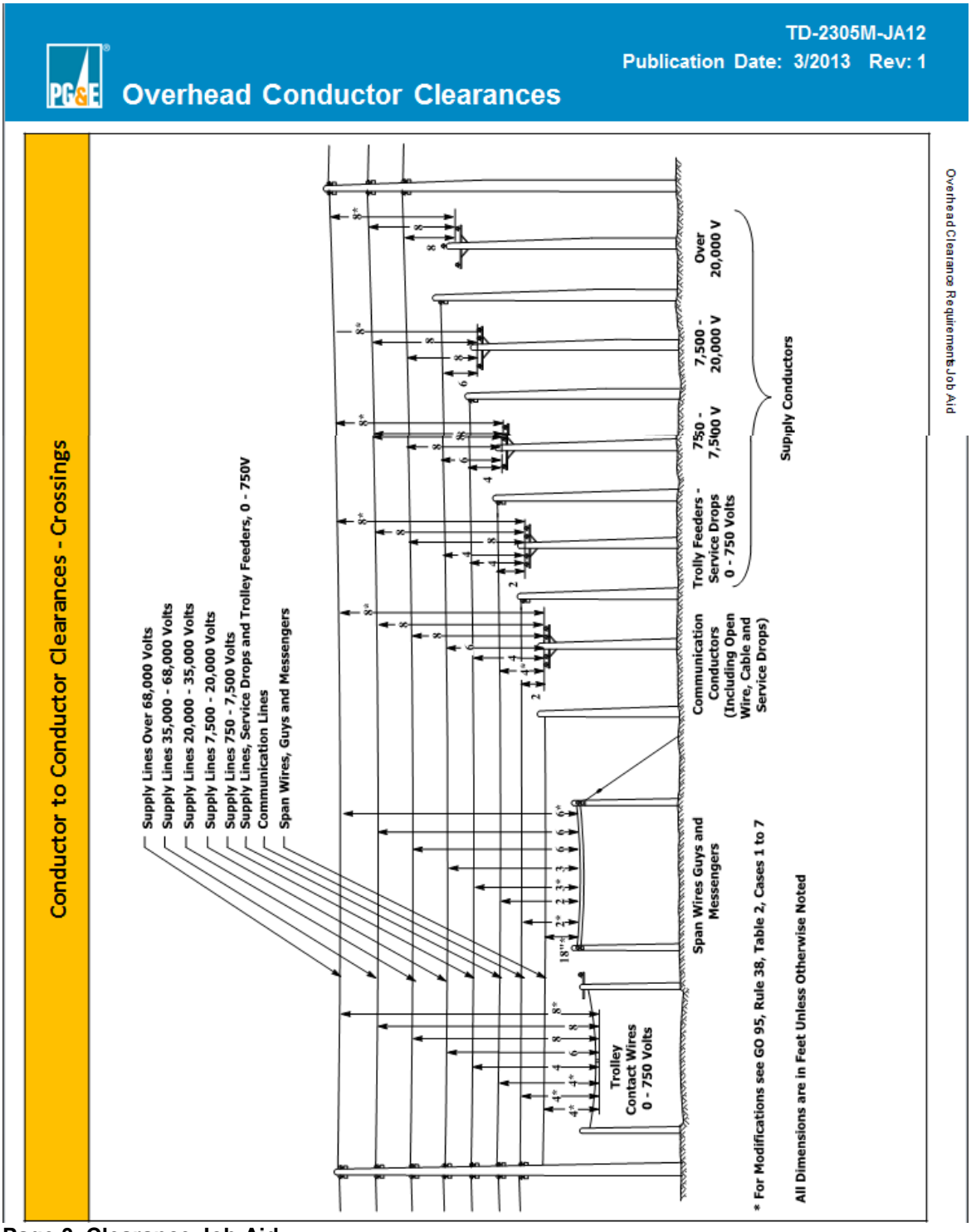
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Overhead Conductor Clearances



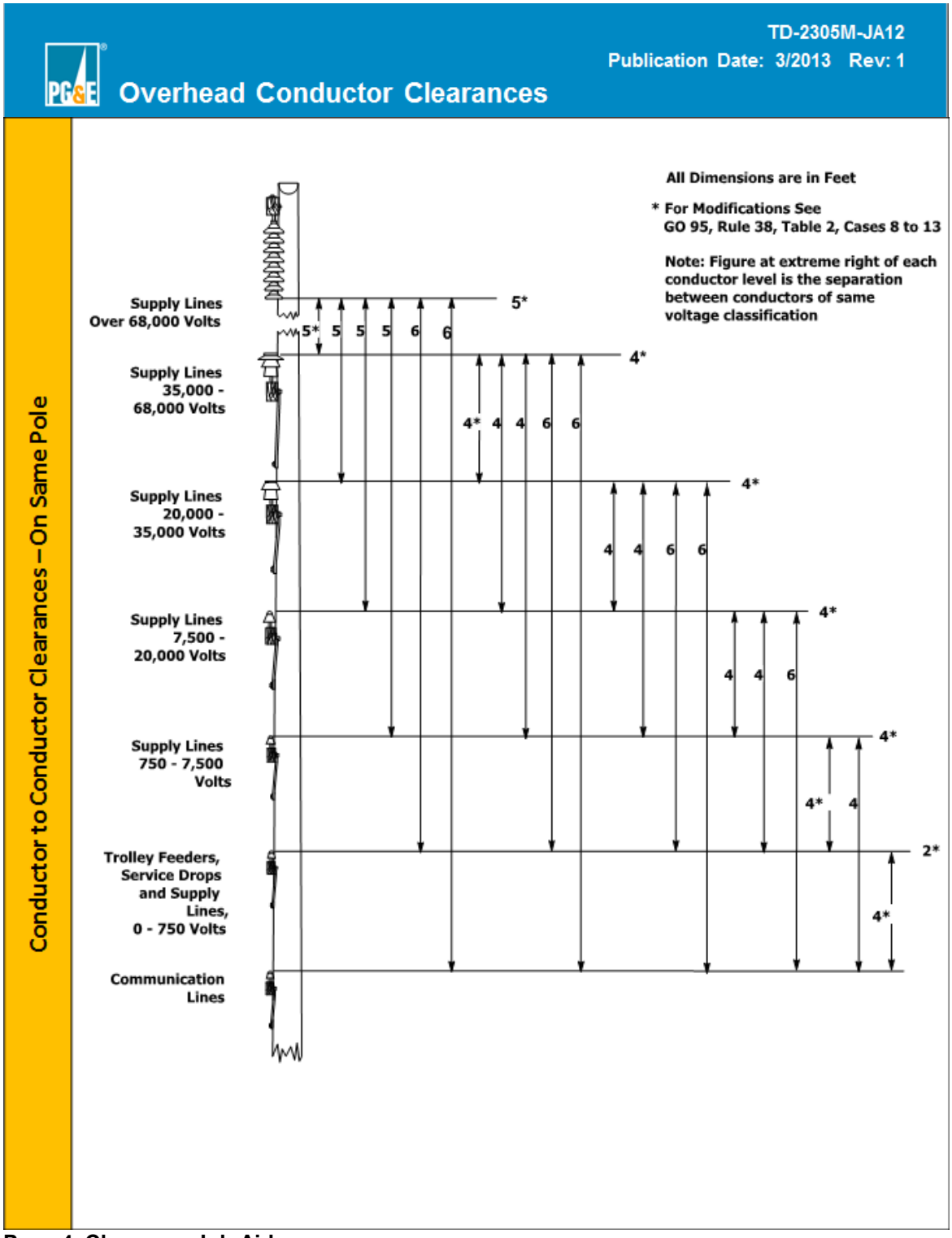
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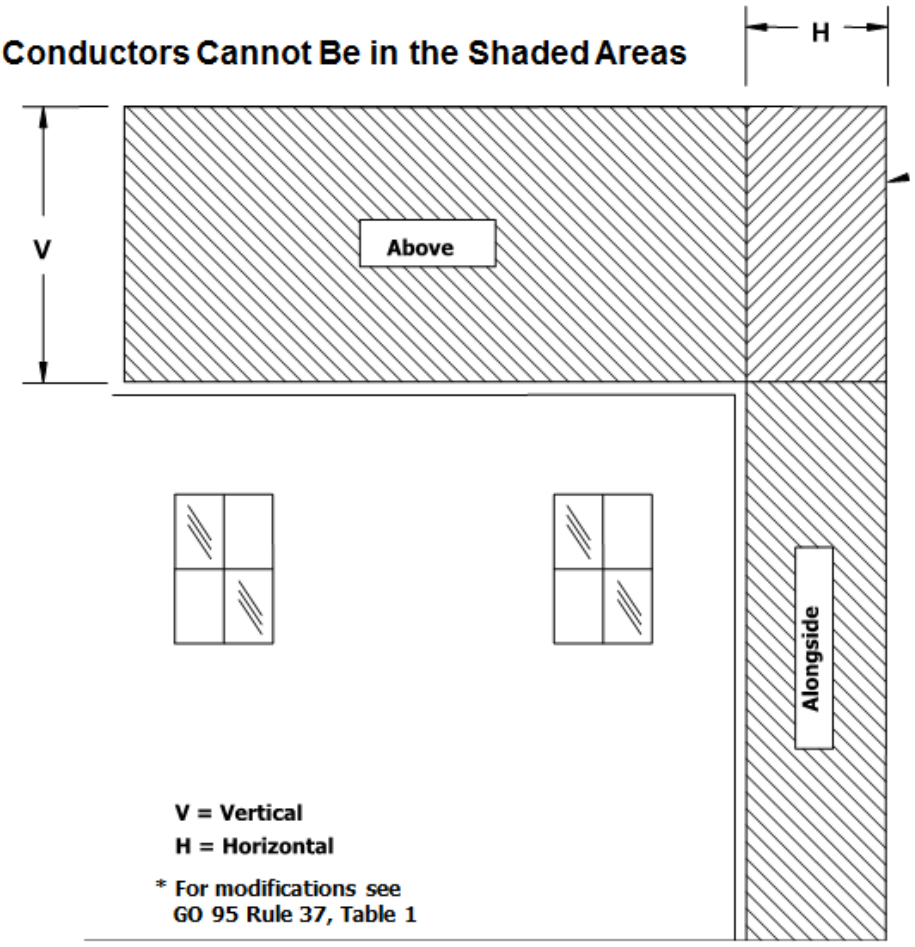
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Overhead Conductor Clearances

Conductor to Building Clearances

Conductors Cannot Be in the Shaded Areas



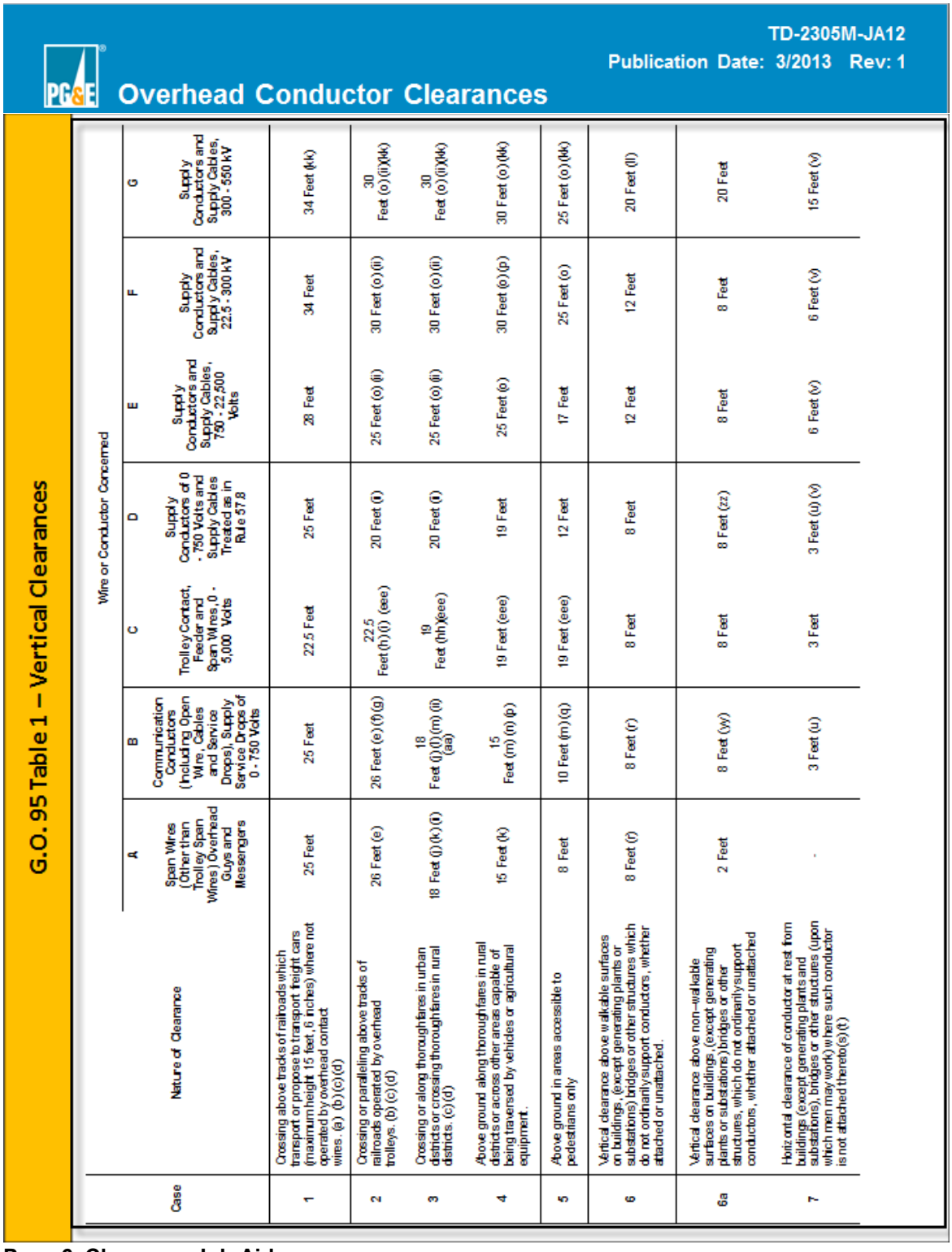
V = Vertical
H = Horizontal

* For modifications see GO 95 Rule 37, Table 1

	Conductor Type					
	Guys	Service Drops (not Attached)	0-750 V Spans	750V-22.5kV	22.5 – 300kV	300-550kV
V (Walkable Surface)	8 ft. *	8 ft. *	8 ft.	12 ft.	12 ft.	20 ft. *
V (Non-Walkable Surfaces: Handrails, Chimneys, Patio Covers, etc.)	2 ft.	8 ft. *	8 ft. *	8 ft.	8 ft.	20 ft.
H		3 ft. *	3 ft. *	6 ft.	6 ft. *	15 ft. *

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Overhead Conductor Clearances

G.O. 95 Table 1 – Vertical Clearances

Case	Nature of Clearance	Wire or Conductor Concerned						
		A	B	C	D	E	F	G
		Span Wires (Other than Trolley Span Wires) Overhead Guys and Messengers	Communication Conductors (Including Open Wire, Cables and Service Drops), Supply Service Drops of 0 - 750 Volts	Trolley Contact, Feeder and Span Wires, 0 - 5,000 Volts	Supply Conductors of 0 - 750 Volts and Supply Cables Treated as in Rule 57.8	Supply Conductors and Supply Cables, 750 - 22,500 Volts	Supply Conductors and Supply Cables, 22.5 - 300 kV	Supply Conductors and Supply Cables, 300 - 550 kV
1	Crossing above tracks of railroads which transport or propose to transport freight cars (maximum height 15 feet, 6 inches) where not operated by overhead contact wires. (a) (b)(c)(d)	25 Feet	25 Feet	22.5 Feet	25 Feet	28 Feet	34 Feet	34 Feet (kk)
2	Crossing or paralleling above tracks of railroads operated by overhead trolleys. (b) (c) (d)	26 Feet (e)	26 Feet (e)(f)(g)	22.5 Feet (h)(i) (eee)	20 Feet (i)	25 Feet (o) (ii)	30 Feet (o)(ii)	30 Feet (o)(ii)(kk)
3	Crossing or along thoroughfares in urban districts or crossing thoroughfares in rural districts. (c) (d)	18 Feet (j)(k)(ii)	18 Feet (j)(l)(m) (ii) (aa)	19 Feet (hh)(eee)	20 Feet (i)	25 Feet (o) (ii)	30 Feet (o)(ii)	30 Feet (o)(ii)(kk)
4	Above ground along thoroughfares in rural districts or across other areas capable of being traversed by vehicles or agricultural equipment.	15 Feet (k)	15 Feet (m) (n) (p)	19 Feet (eee)	19 Feet	25 Feet (p)	30 Feet (p)(p)	30 Feet (o)(kk)
5	Above ground in areas accessible to pedestrians only	8 Feet	10 Feet (m)(q)	19 Feet (eee)	12 Feet	17 Feet	25 Feet (o)	25 Feet (o)(kk)
6	Vertical clearance above walkable surfaces on buildings, (except generating plants or substations) bridges or other structures which do not ordinarily support conductors, whether attached or unattached.	8 Feet (r)	8 Feet (r)	8 Feet	8 Feet	12 Feet	12 Feet	20 Feet (ll)
6a	Vertical clearance above non-walkable surfaces on buildings, (except generating plants or substations) bridges or other structures, which do not ordinarily support conductors, whether attached or unattached	2 Feet	8 Feet (yy)	8 Feet	8 Feet (zz)	8 Feet	8 Feet	20 Feet
7	Horizontal clearance of conductor at rest from buildings (except generating plants and substations), bridges or other structures (upon which men may work) where such conductor is not attached thereto(s)(t)	-	3 Feet (u)	3 Feet	3 Feet (u) (vv)	6 Feet (v)	6 Feet (v)	15 Feet (v)

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Overhead Conductor Clearances

G.O. 95 Table 1 – Vertical Clearances (cont'd)

Case	Nature of Clearance	Wire or Conductor Concerned							
		A	B	C	D	E	F	G	
		Span Wires (Other than Trolley Span Wires) Overhead Guys and Messengers	Communication Conductors (Including Open Wire, Cables and Service Drops), Supply Service Drops of 0 - 750 Volts	Trolley Contact, Feeder and Span Wires, 0 - 5,000 Volts	Supply Conductors of 0 - 750 Volts and Supply Cables Treated as in Rule 57.8	Supply Conductors and Supply Cables, 750 - 22,500 Volts	Supply Conductors and Supply Cables, 22.5 - 300 kV	Supply Conductors and Supply Cables, 300 - 550 kV	
8	Distance of conductor from center line of pole, whether attached or unattached (w) (x) (y)	-	15 inches (s) (aa)	15 inches (aa) (bb) (cc)	15 inches (o) (aa) (dd)	15 or 18 inches (o) (dd) (ee) (ii)	18 inches (dd) (ee)	Not Applicable	
9	Distance of conductor from center line of pole, whether attached or unattached (w) (x) (y)	-	3 inches (aa) (ff)	3 inches (aa) (cc) (gg)	3 inches (aa) (dd) (gg)	3 inches (dd) (gg) (ii)	1/4 Pin Spacing Shown in Table 2 Case 15 (dd)	1/2 Pin Spacing Shown in Table 2 Case 15 (dd)	
10	Radial centerline clearance of conductor or cable (unattached) from non-climbable street lighting or traffic signal poles or standards, including mastarms, brackets and lighting fixtures, and from antennas that are not part of the overhead line system.	-	1 Foot (u) (rr) (ss)	15 inches (bb) (cc)	3 Feet (oo)	6 Feet (pp)	10 Feet (qq)	10 Feet (tt)	
11	Water areas not suitable for sailboating (tt) (uu) (ww) (xx)	15 Feet	15 Feet	-	15 Feet	17 Feet	25 Feet	25 Feet (kk)	
12	Water areas suitable for sailboating, surface area of: (tt) (vv) (ww) (xx)			-					
	(A) Less than 20 acres	18 Feet	18 Feet	-	18 Feet	20 Feet	27 Feet	27 Feet (kk)	
	(B) 20 to 200 acres	26 Feet	26 Feet	-	26 Feet	28 Feet	35 Feet	35 Feet (kk)	
	(C) Over 200 to 2,000 acres	32 Feet	32 Feet	-	32 Feet	34 Feet	41 Feet	41 Feet (kk)	
	(D) Over 2,000 acres	38 Feet	38 Feet	-	38 Feet	40 Feet	47 Feet	47 Feet (kk)	
13	Radial clearance of bare line conductors from tree branches or foliage (aaa) (ddd)	-	-	18 inches (bbb)	-	18 inches (bbb)	1/4 pin spacing shown in table 2, Case 15 (bbb) (ccc)	1/2 pin spacing shown in table 2, Case 15	

Note: A letter next to a measurement indicates there may be an exception. Refer to G.O. 95 to research.

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Overhead Conductor Clearances

G.O. 95 Table 2 – Conductor to Conductor Clearances

Case No.	Nature of Clearance and Class and Voltage of Wire, Cable or Conductor Concerned	Other Wire, Cable or Conductor Concerned				Supply Conductors (Including Supply Cables)						
		A Span Wires, Guys and Messengers	B Trolley Contact Conductors 0 – 750 Volts	C Comm. Conductors (Including Open Wire, Cables and Service Drops)	D 0 – 750 Volts (Including Service Drops) and Trolley Feeders (a)	E 750 - 7,500 Volts	F 7,500 - 20,000 Volts	G 20,000 - 35,000 Volts	H 35,000 - 75,000 Volts	I 75,000 - 150,000 Volts	J 150,000 - 300,000 Volts	K (kk) 300,000 - 550,000 Volts
	Clearance between wires, cables and conductors not supported on the same poles, vertically at crossings in spans and radially where colinear or approaching crossings											
1	Span wires, guys and messengers (b)	18 (c)	48 (d, e)	24 (e)	24 (e)	36 (f)	36	72	72	78	78 (gg)	138 (hh)
2	Trolley contact conductors, 0 - 750 volts	48 (d, e)	-	48 (d)	48 (d, h)	48	72	96	96	96	96 (gg)	156 (hh)
3	Communication conductors	24 (e)	48 (d)	24	48 (i)	48 (dd)	72	96	96	96	96 (gg)	156 (hh)
4	Supply conductors, service drops and trolley feeders, 0 - 750 volts (qq)	24 (e)	48 (d, h)	48 (i)	24	48	48	96(oo)	96	96	96 (gg)	156 (hh)
5	Supply conductors, 750 - 7,500 volts (qq)	36 (f)	48	48 (dd)	48	48 (h)	72	96(oo)	96	96	96 (gg)	156(hh)
6	Supply conductors, 7,500 - 20,000 volts (qq)	36	72	72	48	72	72	96(oo)	96	96	96 (gg)	156 (hh)
7	Supply conductors, more than 20,000 volts (qq)	72 (g)	96 (g)	96 (g)	96 (g, oo)	96 (g, oo)	96 (g, oo)	96 (g, oo)	96 (g)	96	96 (gg)	156 (hh)
	Vertical separation between conductors and/or cables, on separate crossarms or other supports at different levels (excepting on related line and buck arms) on the same pole and in adjoining midspans											
8	Communication Conductors and Service Drops	-	-	12 (j, rr)	48 (k, l, m, n, pp)	48(k)	72 (m, n)	72(m)	72	78	87 (gg)	147 (hh)
9	Supply Conductors Service Drops and Trolley Feeders, 0 - 750 Volts	-	-	48 (k, l, m, n, pp)	24 (h, k, m, o)	48 (k, m, p)	48 (k, m, p)	72 (m, nn)	72	78	87 (gg)	147 (hh)
10	Supply conductors, 750 – 7,500 volts	-	-	48 (k)	48 (k, m, p)	48 (m, o, r, ee)	48 (m, q)	48 (m, q)	48 (q)	60 (ff)	90 (gg)	150 (hh)

Note: A letter next to a measurement indicates there may be an exception. Refer to G.O. 95 to research.

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Overhead Conductor Clearances

G.O. 95 Table 2 – Conductor to Conductor Clearances (Cont'd)

Case No.	Nature of Clearance and Class and Voltage of Wire, Cable or Conductor Concerned	Other Wire, Cable or Conductor Concerned					Supply Conductors (Including Supply Cables)					
		A Span Wires, Guys and Messengers	B Trolley Contact Conductors 0 – 750 Volts	C Comm. Conductors (Including Open Wire, Cables and Service Drops)	D 0 – 750 Volts (Including Service Drops) and Trolley Feeders (a)	E 750 - 7,500 Volts	F 7,500 - 20,000 Volts	G 20,000 - 35,000 Volts	H 35,000 - 75,000 Volts	I 75,000 - 150,000 Volts	J 150,000 - 300,000 Volts	K (kk) 300,000 - 550,000 Volts
	Vertical clearance between conductors on related line arms and buck arms											
14	Line arms above or below related buck arms (s , t)	-	-	6	12 (u)	18 (u)	18 (u)	24	48	60 (ff)	90 (gg)	150 (hh)
	Horizontal separation of conductors on same crossarm											
15	Pin spacing of longitudinal conductors vertical conductors and service drops (v , w)	-	-	3 (x)	11½ (h , x)	11½(x)	17½(x)	24 (x)	48	60 (ff)	90 (gg)	150 (hh)
	Radial separation of conductors on same crossarm, pole or structure—incidental pole wiring											
16	Conductors, taps or lead wires of different circuits (v , y , s)	-	-	3 (x)	11½ (h , x)	11½(x)	17½(x)	24 (x)	48	60 (ff)	90 (gg)	150(hh)
16a	Uncovered, grounded, non-dielectric fiber optic cables on metallic structures, in transition (ss)	-	15	15	15	18	18	18	18	24	36	120
17	Conductors, taps or lead wires of the same circuit (v , s , aa)	-	-	3	3	6	6	12	24	60 (ff)	90 (gg)	150 (hh)
	Radial separation between guys and conductors											
18	Guys passing conductors supported on other poles, or guys approximately parallel to conductors supported on the same poles	-	-	3	11½	11½	17½	24	36	36 (ff)	78 (gg)	138(hh)

Note: A letter next to a measurement indicates there may be an exception. Refer to G.O. 95 to research.

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Crossarm Evaluation Job Aid – Summary

GENERAL INFORMATION:

Environmental conditions throughout the service territory expose support structures to a variety of conditions that can cause or accelerate deterioration of wood components. This section provides guidelines for assessing wood cross arms. Engineering requirements are identified in the Electric Wood Crossarm Assessment Utility guideline TD-2301P-01-JA01.

Procedure:

During detailed inspections, examine wood cross arms and assess their condition for all compelling abnormal conditions, the crossarm will be replaced with a composite crossarm and associated hardware.

Compelling Abnormal Condition is any condition that needs to be addressed in the next 5 years.

Identify onditions such as crossarm configuration, number of phases, location (eg, urban, rural, forest, inaccessible, traffic, etc.), loading (eg, double/triple arms, dead ends, alley arms, proximity to trees, angles/conductor size, heavy loading, damaged wood pins, etc) and the likelihood of these conditions contributing to further deterioration or failure of the crossarm or attached components.

Often cross arms experience significant decay on the top of the arm without exhibiting clues that are visible from the ground[1]. For this reason, arms that exhibit two or more of the following characteristics are more likely to decay on the top and should be considered for a more detailed aerial/climbing inspection:

- Arms that appear to be greater then 50 years old[2](based on age of pole, presence of wood pins, brown/glass insulators, or other indicators).
- Arms mounted on poles where the pole top is showing signs of decay or crowning.
- Severely weathered arms or arms rounded or apparently decayed ends.
- Damaged wood pins or elongated pinholes.
- Active moss/vegetation growth.
- Presence of woodpecker holes (greater than one inch diameter) on the arm
- Arms in areas of higher rainfall/moisture and reduced sunlight such as those in many coast and mountain areas.
- Wood pins on arms located in agricultural areas or orchards contaminated by aerial spraying and dirt, which contributes to tracking and arm or pin deterioration.

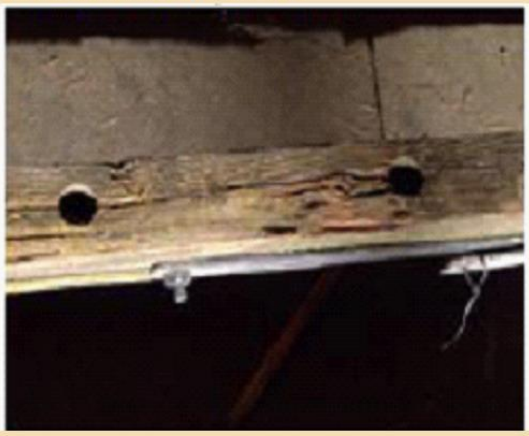
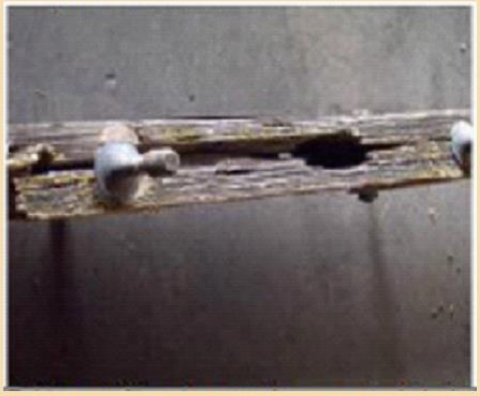
[1] Examples of top and bottom views of crossarm conditions are shown in table 2

[2] Many, but not all, arms prior to 1955 were untreated.

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Crossarm Evaluation Job Aid

Table 2 – Crossarm Grading Aid

BOTTOM VIEW	TOP VIEW
Evidence of decay near hole 	Evidence of Significant Decay 
Enlarged hole, minor moss/discoloration/splits near pin hole 	Enlarged hole, minor moss/discoloration/splits near pin hole 
Evidence of tracking/burning near brace and pin holes 	Evidence of burning near brace and pin holes 

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Crossarm Evaluation

Corrosion Examples	
Arm completely broken/fractured	 Priority A (make safe immediately)
Primary squatter (wood pin). Split within 2" of pinhole .	 Priority B (Replace 0-3 months)

Crossarm Evaluation Job Aid

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Crossarm Evaluation

Corrosion Examples	
Secondary arm broken. Split/fractured within 2" of bolt holes in heavy tree area.	 Priority E (Replace 0-12 months).
Evidence of pole top and face of crossarm decay indicate need for more detailed inspection to better assess extent of arm top decay and condition and to determine if the remaining wood is sufficient to support the brace	 Priority E (Replace 0-12 months).
Significant Deterioration. Both arms are broken/split. Temporary repair needs to be made permanent.	 Priority E (Replace 0-12 months).

Crossarm Evaluation Job Aid

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Crossarm Evaluation

Corrosion Examples	
Moderate Deterioration.	 • Split within 2" of pin. • No other evidence of damage, burning, decay. • Confirm if insulator on double arm is adequate to support strain • No Compelling Abnormal Condition • No repair or reporting required. • Inspect during next cycle.
Moderate Deterioration	 • Top of arm showing signs of decay / deterioration within 2" of each side of brace hole. • No Compelling Abnormal Condition • No repair or reporting required. • Inspect during next cycle.

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PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_124-Q007		
PG&E File Name:	GRC-2023-PhI_DR_TURN_124-Q007		
Request Date:	February 15, 2022	Requester DR No.:	TURN-PG&E-124
Date Sent:	March 2, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Katy Morsony

SUBJECT: PG&E-4, CHAPTER 10, OH AND UG ELECTRIC ASSET INSPECTIONS

QUESTION 007

Following up on the 2016 EDPM Manual (WMCE2020-DR-TURN-DR-7-2Atch02), p. 3 of the Inspections section (p. 127 of the PDF), PG&E's instructions to Compliance Inspectors include, "The Compliance Inspector's primary responsibility when inspecting an overhead or underground electric facility is to examine and record any Compelling Abnormal Conditions that, in the judgment of the inspector, will adversely impact safety or service reliability *within 12 months*" (*emphasis* added)." At p. 1 of Job Aid: Overhead Inspection (TD-2305-JA02, Rev. 7, attached as Atch02 to 2020WMCE_DR_TURN_017-Q01 in the 2020 WMCE (A.20-09-019)), however, PG&E's instructions state: "Compelling Abnormal Condition is defined as being any electric distribution pole, equipment, component, conductors, vegetation or third party condition that cause a safety or *fire ignition risk that may adversely impact public safety and/or service reliability in the next five (5) years*."

a. Please provide the rationale for increasing the reference timeframe for expected replacements from 1 year to 5 years, distinguishing between considerations relevant to (i) HFTD areas and (ii) non-HFTD areas, if applicable.

b. Prior to the WSIP, the inspection cycle was 5 years. Please provide any and all of PG&E's justification for defining Compelling Abnormal Conditions requiring attention in the next 12 months, rather than 5 years.

c. Please provide a brief description and any supporting materials (standard operating procedures, job aid, training material, or the like, with citations to the relevant page number) outlining how inspectors issue EC Notifications for conditions that may become an Compelling Abnormal Condition that do not immediately but will impact safety (including wildfire-related safety) and/or reliability within the (i) year (for routine, non-WSIP inspections) and (ii) next 5 years (for enhanced, WSIP inspections) for the following structures and equipment types:

   (To the extent that any of the Compelling Abnormal Conditions identified as examples for the structures and equipment listed in this subpart (e.g., "degree to which the pole is damaged" for Poles) are conditions that either are present or

not at the time of inspection, instead of time dependent (i.e., they are the type that, while they may not present as Compelling Abnormal Conditions when the inspection is performed, could be become Compelling Abnormal Conditions within 5 years), please identify such conditions.)

i. Poles (including but not limited to the degree to which the pole is damaged, broken, burnt, deformed, exhibits corrosion, gunshots, cracking, or decay, woodpecker damage, and/or reduced circumference)

ii. Crossarms (including but not limited to the degree to which a crossarm is damaged, broken, burnt, decayed, rotten, loose, missing hardware or showing signs of bent bolts or brackets, gun shots, insect damage or woodpecker damage, splitting that compromises integrity, and/or contribution of configuration, number of phases, location, loading, etc. to further deterioration or failure of the crossarm or attached components)

iii. Conductors (including but not limited to cracked or damaged insulation, arcing or burn marks, corrosion, broken strands, gun shot, deterioration, annealing, bird caging, cracked or hotlegged service conductor, splice-prevented free movement, broken or otherwise damaged or missing tie wire, vegetation entanglement, excessively corroded or damaged conductors, dead-end hardware with the potential to drop the conductor, damaged or corroded splices, splices tied too close to insulator, missing spreader bracket(s), secondary connector installed on primary conductor, mixed-metal connections made with a copper-over-aluminum configuration, incorrectly installed Change (tap) Clamps, the presence of floaters, a broken or unsecure service bob, conductor clearance, and/or uneven or improper sag or diminished conductor clearance)

iv. Insulators (including but not limited to evidence of arcing and tracking (or just tracking), chipped, cracked, corroded, contaminated, flashed, broken, or damaged insulator, and/or squatting insulator)

v. Transformers (including but not limited to leaking/weeping stain and/or corrosion)

d. Please provide a brief description and any supporting materials (standard operating procedures, job aid, training material, or the like, with citations to the relevant page number) outlining how inspectors issue EC Notifications for conditions that due to the presence of a fire ignition risk have the potential to become Compelling Abnormal Conditions for the each of the structures and equipment types identified in Subpart c.

e. Please identify the number of (i) pole and (ii) non-pole ECs that PG&E wrote during the WSIP that were written because the structures, equipment, etc., while not otherwise rising to the level of a Compelling Abnormal Condition at the time of the inspection, was expected to become a Compelling Abnormal Condition with 5 years.

f. If known, please identify the number of (i) pole and (ii) non-pole EC Notifications identified in Subpart e that would not have been written, but for the 5-year instead of 1-year lookout.

ANSWER 007

a. In 2019, guidance for inspectors performing GO 165 inspections was updated to align with guidance being provided to inspectors performing WSIP inspections. See below for comparison of guidance from prior to and beginning in 2019.

   Prior to 2019: Inspectors were instructed to write up compelling, abnormal conditions that need to be addressed in the next 12 months. ECs for these conditions were written up with a maximum priority/duration of E, 12 months.

   Beginning in 2019: Inspectors were instructed to write up compelling, abnormal conditions that need to be addressed in the next 5 years. However, the priority model did not change, and compelling abnormal conditions would still be written up with a maximum priority/duration for a Priority E tag of 12 month.

b. See response for 7a which discusses unchanged priority model.

c. See response for 7a which discusses unchanged priority model.

d. Inspectors issue EC Notifications according to the inspection checklist which was developed from the FMEA (see response to question 5).

e. See response for 7a which discusses unchanged priority model. All pole tags were written during the WSIP.

f. See response for 7a which discusses unchanged priority model.

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_124-Q008		
PG&E File Name:	GRC-2023-PhI_DR_TURN_124-Q008		
Request Date:	February 15, 2022	Requester DR No.:	TURN-PG&E-124
Date Sent:	March 10, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Katy Morsony

SUBJECT: PG&E-4, CHAPTER 10, OH AND UG ELECTRIC ASSET INSPECTIONS

QUESTION 008

Following up on Wildfire Safety Inspections Program, Changes to the GO 165/EC Program, which PG&E provide to TURN in the WMCE proceeding (A.20-09-019), 2020WMCE_DR_TURN_017-Q01Atch01:

a. The footer states, "Some of the measures included in this document are contemplated as additional precautionary measures intended to further reduce the risk of future ignitions following the 2017 and 2018 Camp wildfires."
    i. Please identify the measures that "[PG&E] contemplated as additional precautionary measures intended to further reduce the risk of future ignitions following the 2017 and 2018 Camp wildfires."
    ii. For each of the measures that is included in the referenced document but not identified in the response to Subpart a.i, please identify each reason that it was included as a change to the routine, GO165-based inspection approach.
b. At p. 3, PG&E states under New Guidance for Conductors, "Inspect all connections; write EC notifications to replace all connectors with dissimilar metals that are incorrectly installed (copper over aluminum is incorrect):"
    i. When did PG&E discover that there are connections with copper over aluminum on its system?
    ii. When did PG&E begin to understand that a copper-overaluminum, connector configuration has fire-ignition-related concern associated with it?
    iii. When did PG&E begin to understand that a copper-overaluminum, connector configuration has non-fire-ignition, safety and/or reliability concerns associated with it?
c. At p. 3, PG&E states within New Guidance for Floaters, "Floaters are ALWAYS emergency; stand-by required."

i. Please identify the recorded number of Floaters for which EC Notifications were written, disaggregated into priorities by Priority A, B, and E, for each year, 2016-2021.

ii. Please provide the basis for the requirement under New Guidance as compared to the requirement for a priority A, B, or E notification under the Previous Guidance.

iii. Please provide any studies, analysis, reports, etc. that support PG&E's new requirements for priority and duration.

d. At p. 3, PG&E requires the inspector to "[w]rite ECs for ALL LAPP Insulators."

i. When did PG&E begin to understand that LAPP insulators have fire-ignition-related concerns associated with them?

ii. When did PG&E begin to understand that LAPP insulators have non-fire-ignition, safety and/or reliability concerns associated with them?

iii. Please provide any studies, analysis, reports, etc. that support PG&E's new requirement that all LAPP insulators be removed from service.

e. At p. 3, PG&E requires that insulator types not be mixed and that a replacement of one insulator requires inspectors/field crews to replace the full set of affected insulators under the New Guidance.

i. When did PG&E begin to understand that the practice of mixing of insulators has (1) fire-ignition-related and/or (2) non-fire-ignition safety and/or reliability concern associated with it? Please respond separately for subparts e.i.1 and e.i.2, if different.

ii. What is PG&E's knowledge of when the utility industry began tounderstand that the practice of mixing of insulators has (1) fireignition-related and/or (2) non-fire-ignition safety and/or reliability concern associated with it? Please respond separately for subparts e.ii.1 and e.ii.2, if different.

iii. When did PG&E issue the requirement that a full set of insulators must be replaced if an insulator is tagged?

iv. Please provide any studies, analysis, reports, etc. that support PG&E's new requirement that all insulator types not mixed.

f. At p. 3, PG&E requires for Insulators – Primary Squatters under New Guidance, "Primary squatter ECs now required to be max priority E, 12 month duration," but only required a "minimum [of] Priority F/5 years" under the Previous Guidance.

i. Please identify the recorded number of Primary Squatters written as (i) Priority E and (ii) Priority F EC Notifications in each year, 2016-2021. For each priority, please identify the number of Primary Squatters that were written for each Duration for which EC Notifications for Primary Squatters were written – e.g., 10 for 12 months, 20 for 5 years, and X number for Y years, etc., for any other Duration for which EC Notifications for Squatters were written.

ii. Please provide any studies, analysis, etc. that support PG&E's new requirements for priority and duration.

g. At pp. 3-4, please provide an Excel-formatted spreadsheet with responses to each of the following questions for each of the Subparts (i.e., i-xiv) below:

- What negative effect(s) (e.g., broken conductor, sparks, etc.) can the following conditions create in the field?
- What is/are the cause(s) of such negative effect(s)? Please provide a brief description.
- What are the potential consequences if the negative effects that PG&E identifies for a particular negative effect occur? Please identify and explain each of the specific fire-ignition, non-fire-ignition-safety, and reliability consequences, as relevant.
- Clarify whether the condition could cause an inspector to write a fireignition-related EC Notification without the underlying condition also being considered a non-fire-ignition-safety-related (e.g., injury, death, etc.) and/or reliability-related Compelling Abnormal Condition and briefly describe how such a Compelling Abnormal Condition profile is possible.

i. Secondary connectors improperly used in on primary conductor

ii. Connectors with dissimilar metals that are incorrectly installed (i.e., copper over aluminum)

iii. Automatic splices that are damaged

iv. Automatic splices that are corroded

v. Automatic splices that are tied too close together, preventing free movement of the splice with the conductor

vi. Uneven conductor

vii. Annealed copper conductor (6 or 4 solid)

viii. Missing spreaders for >135 spans with open-wire secondary/rack construction

ix. Floaters

x. Chipped, cracked, contaminated, broken, or damaged insulator

xi. Mixed insulator types

xii. LAPP insulators

xiii. Primary squatters

xiv. OH transformers that exhibit signs of dried oil or oil stain

h. At p. 5, PG&E lists numerous Tier 2/3 Inventory Items that were not required under the GO 165-based inspection guidance.

i. Please provide the number of items that WSIP inspectors identified for inclusion in the inventory for each of the categories listed.

ii. Please identify the number of EC Notifications that were written for each of the categories listed in each year 2016-2021, disaggregated between (i) HFTD areas and (ii) non-HFTD areas.

iii. Please identify and explain each reason that the inventory of the each of the identified equipment types or conditions built up.

ANSWER 008

a.i. PG&E implemented various additional precautionary measures intended to further reduce the risk of future ignitions following the 2017 and 2018 wildfires. Some of these additional measures include:

1. Conductors - where signs of arcing or damage to a conductor is identified, PG&E now performs an inspection for arcing, deterioration, burn marks, broken strands, and bird caging through the entire span.
2. Conductors - where inspections identified an insulator was pulled out of the arm, primary and secondary are now considered an emergency, and replace immediately.
3. Crossarms/Framing - where equipment has been damaged due to (a) impact/gunshot, (b) woodpecker/other bird damage, (c) bent bolts or brackets, (d) burns, (e) decay, (f) splitting due to weathering or (g) rot causing internal decay - if the equipment needs to be addressed in the next 5 years, the item is written up to be replaced.
4. Poles - when poles are identified with reduced diameter, degradation, shell rot or leaning or overstressed due to overloading, PG&E writes an EC for testing pole loading.

a.ii. PG&E implemented various additional precautionary measures intended to further reduce the risk of future ignitions following the 2017 and 2018 wildfires. Reasons for taking these additional mitigation measures is provided below:

1. Conductors - Conductors may be missing vibration dampers, splices may have fallen, or termination is too close to the dead-ends. Damage may also be caused by corrosion (e.g. bail style dead ends), mechanical stress from snow loading or weaking from annealing. Small conductors may be more susceptible to failure over time compared to large conductors.
2. Crossarms/Framing - Broken cross-arms may result in conductor falling to the ground due to high wind condictiones or weather events, vegetation clearance or 3rd party damage.
3. Poles - Damaged/broken poles may result in conductor falling to the ground. A pole may fall due to high wind conditions, severe storms, contact with vegetation, damage by a 3rd party (e.g. vehicle crash), overloading (mechanical) or weather event. Reduced diameter of a pole can result in weakened pole, lower class rating and may be susceptible to overload, cracking or breaking.

b.i. PG&E has known that there are connections in its systems with copper over aluminum since 1952. PG&E later started to provide guidance to inspectors that when making aluminum-to-copper connections, one should assemble the conductors such that the copper conductor is always below the aluminum conductor to prevent damage to the aluminum conductor caused by copper salts draining onto the aluminum. For larger conductor connections, it may be necessary that the conductors be positioned horizontally. Please see attachment "GRC-2023-PhI_DR_TURN_124-Q008Atch01", "GRC-2023-PhI_DR_TURN_124-Q008Atch02", and "GRC-2023-PhI_DR_TURN_124-Q008Atch03".

b.i.i This guidance was given to system inspections in 2019 after the fires in 2017 and 2018. The risk associated is much greater with the effects of climate change. This determination was made in collaboration with various teams including Asset Strategy, Standards, and System Inspections FMEA meetings. Please see Page 18 of attachment "GRC-2023-PhI_DR_TURN_124-Q008Atch04".

b.i.i.i. This guidance has been provided since 1952. Reference document 028852 Rev 3,15 and 1952 jpg. Please see attachment "GRC-2023-PhI_DR_TURN_124-Q008Atch01", "GRC-2023-PhI_DR_TURN_124-Q008Atch02" and "GRC-2023-PhI_DR_TURN_124-Q008Atch03".

c.i. Please see "GRC-2023-PhI_DR_TURN_124-Q008Atch05" for recorded number of floaters.

c.i.i. Earlier guidance provided to inspectors was to use an Impact / Probability Matrix to determine the risk and create an EC notification accordingly. This guidance was later revised in 2019, and the decision was risk based - PG&E noted that an unattached energized conductor will hang lower and swing at a different moment than those that are still attached. Please see page 188 for the Impact / Probability Matric in attachment "GRC-2023-PhI_DR_TURN_124-Q008Atch06", and page 30, note 3 of attachment "GRC-2023-PhI_DR_TURN_124-Q008Atch07".

c.i.i.i. PG&E has not identified any of these to provide.

d.i. Current and previous construction guidance has been provided since 1972, and PG&E understood that LAPP brand insulators manufactured prior to 1972 were a known issue. PG&E disagrees that all LAPP insulators have fire and non-fire ignition-related concerns associated with them. The issue around LAPP insulators was very specific to insulators manufactured by one vendor. These insulators date back to sometimes in 1970s, and are no longer utilized by PG&E.

Please see Page 1, Note 8 in attachment " GRC-2023-PhI_DR_TURN_124-Q008Atch08", and most current procedures in attachment " GRC-2023-PhI_DR_TURN_124-Q008Atch09". Please also see attachment " GRC-2023-PhI_DR_TURN_124-Q008Atch10" for PG&E's LAPP insulator replacement program. PG&E does not provide this guidance in its Overhead Inspection Job Aid (Please see attachment "GRC-2023-PhI_DR_TURN_124-Q008Atch07" or

the Systems inspection checklist ELEC-1000 (Please see attachment "GRC-2023-PhI_DR_TURN_124-Q008Atch11"

d.i.i. For non-fire-ignition, safety and/or reliability concerns related to LAPP insulators, see response to d.i.

d.i.i.i PG&E has not identified any of these to provide.

e.i. In 2012, PG&E made polyethylene pin insulators the preferred insulator for new installations, including bare conductor, tree wire, and covered wire jumpers. Please see Page 1, Note 1 in attachment " GRC-2023-PhI_DR_TURN_124-Q008Atch12".

This included the guidance of replacing all insulators if one was to be replaced. The rational was that mixed insulator types have different leakage properties, and this makes the bonding which is installed to prevent tracking become ineffective. This would have a negative effect on the structure itself and possibly lead to pole fires. There are also the financial reasons of changing three insulators at the same time since the crew was already on the job changing one insulator.

e.i.i. PG&E cannot identify when the utility industry began to understand this practice, however SME's current practice is to replace these insulators.

e.i.i.i. PG&E issued the requirement that a full set of insulators must be replaced if an insulator is tagged in 1998. Please see Page 1, Note 5 in attachment "GRC-2023-PhI_DR_TURN_124-Q008Atch13".

e.i.v. PG&E has not identified any of these to provide.

f.i. Please see "GRC-2023-PhI_DR_TURN_124-Q008Atch05" for recorded number of Primary Squatters.

f.i.i. This is discussed in PG&E's FMEA, see "GRC-2023-PhI_DR_TURN_124-Q005Atch01".

g. Please see "GRC-2023-PhI_DR_TURN_124-Q008Atch16" for responses to subparts i-xiv.

h.i. Please see "GRC-2023-PhI_DR_TURN_124-Q008Atch14" for items that WSIP inspectors identified for inclusion in the inventory for each of the categories listed.

h.i.i. Please see "GRC-2023-PhI_DR_TURN_124-Q008Atch15" for inventory items that require an EC. In the time given to respond to this request, PG&E was not able to provide the data requested.

h.i.i.i. PG&E determined that guidance was needed for these assets and included guidance in the WSIP.

NOTES:

GENERAL:
1. This drawing covers the instructions for making aluminum-to-aluminum or aluminum-to-copper current carrying connections with parallel groove clamps, tap clamps and compression type connectors. For the purposes of this drawing "covered" conductors include 0-5kV. weatherproof conductors, all 600V. insulated wires or cables, and exclude "tree wire". (Refer to Dwg. 015195 for tree wire connections).

CLEANING AND SEALING:
2. Aluminum surfaces are normally coated with an invisible layer of aluminum oxide. Since this oxide has a high electrical resistance, it must be removed to insure a good electrical connection, capable of carrying heavy currents when necessary, to maintain a good connection, the joint must be sealed with a liberal coating of Inhibitor Compound such as No-Ox-Id "A Special" (in 36 lb. containers ---Code 49-5183).

CONNECTORS: All new connectors shown on this drawing are now factory cleaned and coated with a film of compound and contact surfaces need not be wire brushed in the field. Contact surfaces of salvaged connectors should be wire brushed and coated in the manner described for conductors below.

CONDUCTORS: Since the oxide film begins to re-form immediately after removal unless the surface is coated with compound, it should be removed by wire brushing after the compound has been applied. This can best be done by applying a liberal quantity of compound to the wire brush and then wire brushing the conductor surface thoroughly. Sufficient quantity of compound should be applied to the conductor to fill the strands and also the connector grooves.
In making copper-to-aluminum connections it is important to clean and coat both copper and aluminum conductors with inhibitor compound to prevent damage to the aluminum by corrosion.

SEALING OR TAPING
3. In general, where either or both conductors are bare, do not seal or tape connector. Otherwise, the aluminum may corrode due to moisture trapped by the sealant. Do not use mastic sealant or tape on insulated service sleeves except in underground applications specified on Sheet 6.

4. When both conductors are covered, seal connector with mastic sealant pads as specified on Sheet 9.
As an alternate PVC plastic tape, Code 38-4158, may be used.

POSITIONING OF CONDUCTORS:
5. Turn ends of covered aluminum conductor downward to prevent entrance of moisture under the covering. Do not tape over bare aluminum (such as service drop cable neutral) to hold in position as moisture may be trapped and aluminum corroded.

6. In making copper-to-aluminum connections, form smaller conductors so that copper is always below the aluminum to prevent damage to the aluminum by copper salts draining downward. Install large conductors in clamps on copper-to-aluminum connections so that conductors are positioned horizontally.

REMOVAL OF COVERING:
7. When removing insulation or W.P. covering from aluminum conductor, normally make a tapered "pencil" cut, rather than a square or "ring" cut which may damage aluminum by deep nicking. Exception: Square cuts are required for insulated service sleeves (Sheet 6).

CONNECTOR APPLICATION GUIDE:
8. Where conductor size combinations permit, the following connectors are specified:
(a) 2.4-35kV. Secondary, and Services-Pole End: PG Clamps (Sheet 4), unless service sleeves are applicable.
(b) Services- Customer's End: Service Sleeves (Sheet 6).

9. Exception to Note 8 is as follows:
(d) Service Sleeves (Sheet 6) are limited to conductors of No. 10 to 1/0. Use PG Clamps for all others.

10. All applications covered in the notes above are detailed on the following sheets.

METER SOCKET CONNECTIONS:
11. Aluminum service entrance conductors may be connected directly to meter socket terminals which are specifically designed and approved for use with aluminum conductors. Thoroughly clean the ends of the conductors and apply a coating of No-Ox-Id "A Special" compound, Code 49-5183, to the ends of the conductors and fill the meter terminals with this compound before making up the connections.

REFERENCE:
Index of drawings applicable to aluminum conductors --- Dwg. 028850, Sheet 1.

REGISTERED PROFESSIONAL ENGINEER T.A. BETTERWORTH No. 1986 ELECTRICAL STATE OF CALIFORNIA

GENERAL NOTES AND REFERENCES

CHG.	DATE	DESCRIPTION
12	4-16-79	Revised Notes 8 and 9. Renumbered Notes 8 thru 11.
11	3-15-76	Revised Notes 1, 3, 4 & 7. Added Sh. 9
10	8-12-70	Added Sheet 8.
9	3-17-65	Minor revisions on Notes 2, 10(a) & 13. Redrawn

APPROVED [redacted]
SUPERV. BY [redacted]
DSGN.
DR.
CH.
O.K.
DATE 11-14-52
SCALE —

SUPV. | BY | CH. | APPD. [redacted]

SUPERSEDES 015012, 015016, 027875
SUPERSEDED BY
SHEET NO. 1 | 9 SHEETS
DRAWING NUMBER 028852 | CHANGE 12

ENGINEERING STANDARD
CONNECTIONS FOR ALUMINUM CONDUCTORS DISTRIBUTION LINES
DEPARTMENT OF ENGINEERING
PACIFIC GAS AND ELECTRIC COMPANY
SAN FRANCISCO, CALIFORNIA

35 M/M NEG. 12
105 M/M NEG. 10

DRAFT





Pre-1972 Lapp and Ohio Brass Pt. 1 Tie Top Insulators, Pre-1979 Gladco Pt. 2 Tie Top Insulators Background Information and Recommendations

October, 2014

[redacted]

Background & Historical Information

During the last five years a total of 9 MPR's have been submitted to report failures of Lapp Parts 1 & 2 (Pre-1972), and Gladco Part 1 (pre-1980) post type insulators, 8 of the MPR's were for Lapp insulators. Premature failure of a small percentage of these insulators at lower than rated cantilever strength was identified back in 1977. Certain vintage of Gladco Pt. 2 and Ohio Brass (OB) Part 1 Tie top insulators were also identified as having similar issues.

The M&C organization has conducted tailboards to their employees reiterating the potential safety issues that breakage of these insulators could present to the public and employees.

These insulators are no longer on the approved for purchase list, and have been removed from available inventory. Identification of these insulators that remain on our system is very difficult to do from the ground, and not documented in our current asset registry, DART.

Engineering Document #022088 in the Overhead Construction Manual provides the following recommendation for insulators that are no longer approved for purchase:

8. Replace and dispose of any of the following insulators either found installed or in storage (i.e., in service centers, in construction yards, on vehicles or trailers):

- *Pin Insulators − All Gladco Insulators, and any old insulators that are not shown in this document or that are removed per this section.*
- *Post Insulators All Gladco insula[redacted]nd earlier), Ohio Brass Part I Tie Top Insulators (1972 and earlier), and any insulators that are removed per this section.*

Background & Historical Information

- During a 15 month period between 1976 and 1977, 13 Pt. 1 OB Tie Top Insulators failed in service and were submitted for testing to the Ohio Brass Company. The manufacturer was unable to explain the exact cause of the failures, but offered to send replacement insulators free of charge for any failed Ohio Brass insulator.
- All of the units exhibited the same failure pattern near the bottom of the porcelain, apparently originating near the chum hole and extending toward the outer circumference of the insulators, below the bottom skirt.
- In October of 1977, the Electric Standards Department requested from T&D Electric Operations the removal from PG&E's Distribution lines of 30-Pt. 1 Ohio Brass Tie Top Insulators manufactured between 1970 and 1972.
- These 30 insulators were to be sent to the Department of Engineering Research (currently known as ATS) for evaluation.
- At the time, approval of the Ohio Brass Company as a supplier of line post insulators was suspended pending satisfactory resolution of the problem.



Background & Historical Information

- In November of 1977, T&D Electric Operations responded by stating that that their department only had 12 failed Part 1 OB Post Type Insulators were on record.
- It is apparent that no testing was conducted at the Department of Engineering Research in 1977 or 1978.
- In 1981, another memo from the Electric Standards Department went out to T&D Electric Operations, this time requesting five to seven Ohio Brass Part 1 insulators from Drum, Shasta and Stockton Division. The intent was once again to test the insulators internally at DER.
- A total of 22 OB Post Type Insulators were submitted for testing at DER, all of them were collected from the foothill areas where they had been subjected to both freezing and very hot ambient temperatures. Out of this sample, 15 had visible cracks and 8 failed at cantilever loading of less than 2800 lbs (their rated strength).
- A set of recommendations came out which included replacement of pre-1971 OB Post Type insulators from the foothill areas of Drum, Shasta, DeSabla and Stockton Divisions.

[redacted]

Background & Historical Information

- In June of 1982, Corporate Accounting Activity Records were researched and identified 27,000 Part 1 Insulators with material code M31-1064 installed from 1970 through 1972. This list included Lapp Part 1 insulators which was the only other manufacturer approved during this time period.
- The objective of this effort was to inspect and identify for removal 15,000 Ohio Brass Part 1 Insulators.
- In September of 1984, the Electric Standards Department issued a memo to all Division Managers requesting that all Lapp and Ohio Brass Part 1, Post Type Insulators purchased between 1970 and 1972 be removed from the field and stored at the local service centers.
- The Lapp insulators were supposed to be packaged and sent to the DER for further testing.
- Corporate Accounting identified Work Orders and GM's for the projects on which the suspect insulators were installed. All distribution poles that were identified as supporting the Lapp and Ohio Brass insulators were located and marked on the traveled side of the pole, seven feet above ground with Pole Marker Tags.

[redacted]

Ohio Brass Insulator Replacement Program

- By the end of the program in 1986, a total of 54,696 of suspect insulators were found, and their supporting poles tagged, these included poles supporting both Lapp and OB Part 1 insulators.
- Approximately 16,000 Ohio Brass Part 1, Post Type Insulators were replaced during a two year period (from mid-1984 to mid-1986).
- After performing numerous tests on Lapp Part 1 insulators removed in 1984, a letter was sent to all Division Managers on November of 1984. Through the letter, the Electric Standards Department requested to discontinue the removal of Lapp Part 1 insulators from service. It was concluded based on the tests done at DER that the Lapp Part 1 insulators did not have a deterioration or manufacturing problem.

[redacted]

Gladco Insulators

- A couple of design flaws were discovered on Gladding Part 2, Post Type Insulators manufactured prior to 1980.

1. The shallow groove on top of the “biscuit” area allowed conductors to slip out easily when tying in the conductor with hot sticks.
2. When installing pre-formed top ties, they did not seat properly and became prone to deformation when wrapped around the “biscuit” area.

- At the beginning of 1981, Gladding changed their tool dies to cut a deeper groove, the radii of the top groove and side groove increased to 1” radius. The changes were made to comply with ANSI Standard C29.7-1977, and to ensure proper seating of pre-formed ties and conductors.
- After these changes were made, the Electric Standards Department recommended that Gladding Part 2, Post Type Insulators manufactured prior to 1980 be installed only for single-phase construction with small conductors (#6 Cu & #4 ACSR).
- From 1982 to 1984 multiple tests were conducted at DER on many samples of Gladding Part 2 Insulators, in most cases their cantilever strength passed the loading test. The Gladding Company went out of business in 1984.

[redacted]

Asset Identification and Data Quality Issues

- Identifying the location of Lapp Parts 1 & 2 and Gladco Parts 1 & 2 insulators using DART is not easy to do at present time. Purchasing records are not available and installation location can only be identified through an up close inspection (within 2 feet of the insulators). These inspections would have to be performed from a bucket truck (1 man operation) or by climbing the poles at locations that are not accessible by bucket trucks.

- Block/plat map, or raster map layer in DART, may indicate the vintage of facilities in the area. The pole date stamp may also indicate the vintage of insulators and other overhead hardware.

- As mentioned above, poles supporting Lapp Part 1 insulators manufactured between 1970 and 1972 were tagged with pole markers when the Ohio Brass Insulator replacement program was happening. This may help identify locations with suspect Lapp insulators.

[redacted]

Recommendations

Recommendations:

- In addition to the M&C organization's recent tailboards communicating the potential safety issue with these insulators, Asset Strategy's recommendation is for the Work Methods and Safety organizations to take the lead in developing and documenting proven safeguard procedures/training/tools for M&C personnel.

- At this time, a video has been produced by the Grass Safety Roots Team to help identify these insulators (Pre-Work checking). See Link below:

  https://www.dropbox.com/s/vr04b28u69qoxmv/2013-08-19%2010.19.13.mov

- Failures of suspect Lapp, Ohio Brass and Gladco insulators should be documented through the MPR process and the material sent to Distribution Standards for review. Suspect insulators adjacent to the failed ones should be removed from service and also submitted through the MPR process to be analyzed at ATS.

- It is also recommended that Distribution Standards issue a bulletin providing background information on the known issues (there is a new generation of line-workers who may not be aware of them), as well as a summary of the following guidelines:

[redacted]

Capital Replacement Projects

Within the Work Area

Major capital replacement projects (e.g. installing/replacing poles, reconductoring, replacing crossarms, adding a third phase, or new line equipment) shall include replacement of all Lapp and Gladco Parts 1 & 2, Post Type insulators installed prior to 1980.

Minor capital projects (e.g. bird mitigation projects, reframing, or installing a set of fused cutouts), shall also include replacement of cracked or suspect insulators as part of the project.

Outside the Work Area

Where these type of insulators are known to exist, or the line was built before 1980, these will be identified by estimating/construction, documented, and will be replaced as part of a multi-year capital replacement plan using the ER Notification process.

Identification/Documentation

All known, LAPP Parts 1 & 2 (Pre-1972), Gladco Parts 1 & 2 (Pre-1980), Post Type Tie Top insulators found outside an existing project work area, should be communicated to the Asset Strategy for future replacement. This will be accomplished via a reporting form, which will serve as a starting point for the ER notification/replacement process. A system wide list will be created which contains all work locations with LAPP/GLADCO insulators.(See example of repo[redacted]

Routine and Emergency Work

Within the Work Area

On routine or emergency work where these type of insulators are found, every effort should be made to replace them when found. In cases where they are not able to be replaced on routine or emergency work, their existence needs to be documented via the reporting form, and sent to the Asset Strategy Organization for future replacement utilizing the ER process.

Outside the Work Area

Where these type of insulators are known to exist/or are just outside the immediate work area, these insulators will be documented via the reporting form as well, and will be replaced as part of a multi-year capital replacement plan using the ER Notification process.

(See example of reporting form on slide 12).

[redacted]

LAPP/Gladco/OB Insulator Reporting Form

LAPP/Gladco/OB Insulator Reporting Form

Reported By: _____ **Date:** _____

Phone: _____

Post

☐ **Lapp Insulator Pt. 1 & 2** ☐ **Gladco Pt. 1 & 2** ☐ **Ohio Brass Pt. 1**

Division: _____

GPS Coordinates (if available): _____

Circuit: _____ **Source Side Device:** _____

Location Description: _____

Include Plat/Block Map with Pole Location(s) marked

Please SCAN and E-Mail this Form/Map to:

[redacted]

Distribution Asset Strategy and Development

TURN 124
DR 8g

	Request	
8G	**At pp. 3-4, please provide an Excel-formatted spreadsheet with responses to each of the following questions for each of the Subparts (i.e., i-xiv) below:**	**What negative effect(s) (e.g., broken conductor, sparks, etc.) can the following conditions create in the field? What is/are the cause(s) of such negative effect(s)? Please provide a brief description.**
i	Secondary connectors improperly used in on primary conductor	Connector failure due to fault current overload may result in thermal runaway and arcing.
ii	Connectors with dissimilar metals that are incorrectly installed (i.e., copper over aluminum)	High resistant connections may result in failure and arcing.
iii	Automatic splices that are damaged	Failure of automatic splices that are damaged may result in a downed conductor and arcing.
iv	Automatic splices that are corroded	Failure of automatic splices that are corroded may result in a downed conductor and arcing.
v	Automatic splices that are tied too close together, preventing free movement of the splice with the conductor	When a vibration is induced to a conductor the vibration forces are amplified where it is restrained. The tie wire or clamp is designed to hold this, a conductor splice is not. This guidance has been provided in our construction standard since 1944. Please see attachment "GRC-2023-PhI_DR_TURN_124-Q8GAtch1"

vi	Uneven conductor	Conductors sagged differently may swing at different rates and come in contact with each other.
vii	Annealed copper conductor (6 or 4 solid)	Annealed conductor are no longer considered to be as strong as designed. Annealed conductors are hazards, and if it fails, the conductor may arc.
viii	Missing spreaders for >135 spans with open-wire secondary/rack construction	This was a construction requirement for rack construction and the spreaders break over time. This may cause conductor spacing issues. Please see Page 1, Notes 1 and 3 in attachment "GRC-2023-PhI_DR_TURN_124-Q6CAtch2".
ix	Floaters	A Floater is where an insulator has fallen off its support. This could be a cross arm or a bracket of various types. The can be reasons for this, such as broken pins, rotten cross arms or loose bolts, etc.. If a conductor is floating it can be low, swing into another structure or an object nearby, or even break due to weight span limitations of adjacent components. This may result in arcing.
x	Chipped, cracked, contaminated, broken, or damaged insulator	Chipped, cracked, contaminated, broken, or damaged insulators are no longer effectively intact and may not perform well resulting in voltage making it to the structure. This may create arcing.

xi	Mixed insulator types	Mixed insulator types have different leakage properties, and this makes the bonding which is installed to prevent tracking to become ineffective. It is also not visually easy to spot a flaw in an insulator when there isn't an identical one next to it. Often, it's the silhouette of an insulator that is different that catches an inspector's eye.
xii	LAPP insulators	Lapp brand insulators manufactured prior to 1972 had a manufacturing defect that was not externally visible. Water could intrude between the ceramic and base, then freeze and break the insulator. This can result in arcing and electrocution hazards.
xiii	Primary squatters	A primary squatter is an insulator energized above 500 volts that is no longer supported above the cross arm and is laying on the arm. This may result in shorting of the skirts on the underside of the insulator and reduceing its effectiveness. The reasons can be a rotten cross arm, or a rotten or broken pin, or loose hardware. This can result in a floater or arcing on the structure.
xiv	OH transformers that exhibit signs of dried oil or oil stain	Overhead transformers use oils as an insulating fluid. Any oil loss is a sign of leaking and/or possible water intrusion. Once the oil is lost or water gets in the coils inside the transformer, this can short out which produces hydrogen gas. The short circuit can also cause arcing which can provide an ignition source for the oil and hydrogen gas.

Response	
What are the potential consequences if the negative effects that PG&E identifies for a particular negative effect occur? Please identify and explain each of the specific fire-ignition, non-fire-ignition-safety, and reliability consequences, as relevant.	**Clarify whether the condition could cause an inspector to write a fire-ignition-related EC Notification without the underlying condition also being considered a non-fire-ignition-safety-related (e.g., injury, death, etc.)**
Secondary conductors improperly used in on primary conductors may cause thermal runaway and arcing.	Yes it could be written that way. However the other underlying conditions are no less severe. Injury and death can result from other things than fire.
Connectors with dissimilar metals that are incorrectly installed (i.e., copper over aluminum) may result in failure and arcing.	Yes it could be written that way. However the other underlying conditions are no less severe. Injury and death can result from other things than fire.
Automatic splices that are damaged may result in downed conductor and arcing.	No
Automatic splices that are corroded may result in downed conductor and arcing.	No
A downed conductor from a failed splice is a saftey concern and electrocution hazard as well as a fire risk.	No

Uneven conductor installation may result in conductors coming in contact with each other.	Yes it could be written that way. However the other underlying conditions are no less severe. Injury and death can result from other things than fire.
If Annealed copper conductors fail, it may result in arcing.	No
Missing spreaders for >135 spans with open-wire secondary/rack construction may result in conductor spacing issues.	Yes it could be written that way. However the other underlying conditions are no less severe. Injury and death can result from other things than fire.
If a conductor is floating, it may result in arcing.	No
Chipped, cracked, contaminated, broken, or damaged insulator may result in arcing.	No

Use of mixed insulator types may result in tracking becoming ineffective.	No
Using LAPP brand insulators may result in arcing and electrocution hazards.	No
Using primary squatters may result in a floater of arcing on the structure.	No
OH transformers that exhibit signs of dried oil or oil stain may result in short circuits.	No

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_124-Q010		
PG&E File Name:	GRC-2023-PhI_DR_TURN_124-Q010		
Request Date:	February 15, 2022	Requester DR No.:	TURN-PG&E-124
Date Sent:	March 10, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra/Paul McGregor	Requester:	Katy Morsony

SUBJECT: PG&E-4, CHAPTER 10, OH AND UG ELECTRIC ASSET INSPECTIONS

QUESTION 010

Re. p. 10-5:22-23, PG&E states, "Starting in 2020, PG&E incorporated the enhanced detailed inspection approach developed in the WSIP across its entire Overhead Inspection Program, including beyond the HFTD areas."

a. Please provide all of PG&E's justifications for expanding the enhanced inspection beyond the non-HFTD areas.

b. Please provide any and all documents supporting this change.

c. Has PG&E calculated a risk-spend efficiency for expanding the enhanced inspection beyond the HFTD areas? If yes, please provide the RSE and all supporting documents.

ANSWER 010

a. PG&E expanded its Overhead Inspection Program to include non-HFTD areas based on its wildfire risk modeling. PG&E calculated risk-spend efficiency for expanding the enhanced inspection beyond HFTD areas. PG&E incorporated the enhanced detailed inspection approach developed in the WSIP to its entire Overhead Inspection Program to proactively identify and address potential sources of wildfire ignition, as well as threats to safety and reliability.

b. See "GRC-2023-PhI_DR_TURN_124-Q010Atch01" for support for change.

c. Yes, PG&E calculated risk-spend efficiency for expanding the enhanced inspection beyond the HFTD areas. This can be seen in workpapers EO-DOVHD-3_RSE Input File.xslm and EO-WLDFR-3_RSE Input File.xlsm as shown below.

   Both workpapers were submitted as:

   GRC-2023-PhI_DR_ED_001Supp01Rev02Atch01 (PG&E's February 25,2022 updated risk modeling workpapers for EO-WLDFR and EO-DOVHD).

   1) In EO-DOVHD-3_RSE Input File.xslm, 'RSE Results' tab:

- Filter Column X10 (Program) to "Inspections - Distribution Overhead" and filter Column Y10 (index) to exclude "HFTD" (i.e. include: Corrosive Regions with Specific Material (ACSR), Elevated Wire-downs (Small Copper Conductors), High Reliability Performance, Moderate Reliability Performance and Poor Reliability Performance).
- For DOVHD non-HFTD tranches, 2023-2026 Program Risk Reduction NPV = 92.338. This is the sum of "2023-2026 Program Risk Reduction NPV" for all the rows.
- The 2023-2026 Capital Cost NPV with PVRR is $0 and 2023-2026 Expense Cost NPV is $112,901,876

2) In EO-WLDFR-3_RSE Input File.xslm, 'RSE Results' tab:

- Filter AA10 (Program) to "Inspections - Distribution Overhead" and filter Column AB10 (index) to exclude all rows with "HFTD," resulting in 1 row for "non-HFTD – Distribution."
- For WLDFR non-HFTD tranches, 2023-2026 Program Risk Reduction NPV = 66.503.
- The 2023-2026 Capital Cost NPV with PVRR is $0 and 2023-2026 Expense Cost NPV is $112,901,876 (same cost as DOVHD)

The combined RSE for enhanced inspection beyond the HFTD areas = (92.338+66.503) / $112,901,876 * 10^6 = 1.406.

Pacific Gas and Electric Company®

Utility Bulletin: TD-2305M-B006
Publication Date: 01/24/2020 Rev: 0

Revised Electric Distribution Inspection Guidelines

SUMMARY

This bulletin provides changes to TD-2305M, Electric Distribution Preventative Maintenance Manual (EDPM) referencing changes implemented as a result of learnings from the Wildfire Safety Inspection Program (WSIP). Specifically:

- Revisions to asset selection process for inspections
- Revisions to inspection frequencies and types of inspections based on learnings from risk analysis performed within Asset Strategy

Level of Use: Informational Use

AFFECTED DOCUMENTS

TD-2305M, "Electric Distribution Preventative Maintenance Manual" (EDPM) and all associated bulletins.

TD-2305B-002, "High Fire Threat Districts (HFTD) for GO 165 Inspections and Patrols" (due dates and cycle times only)

TD-8999B-001 "PG&E's 2019 Corrective Tag Execution Approach"

"Wildfire Safety Inspection Program (WSIP) Compliance Plan and Interim Controls"

TARGET AUDIENCE

Electric distribution maintenance employees, electric engineers, contractors, supervisors, and superintendents involved in the maintenance of distribution facilities.

WHAT YOU NEED TO KNOW

1 Background Information

1.1 Historically, Distribution line has performed inspections on roughly 20% of assets each calendar year, utilizing detailed visual inspections and aerial patrols. The inspection frequency is outlined in TD-2302S Appendix 1.

1.2 Learnings from WSIP have resulted in overhead detailed inspections that generate more data, enabling a better understanding of the health of components on assets. This has led to "WSIP-scope" inspections for detailed visual inspections, which follow an FMEA-based detailed questionnaire to be completed on every asset in scope for detailed inspection.

1. Note: The timeline for this change will be based on technology platform deployments from the System Inspections organization for each asset type (i.e. Overhead/Underground).

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Revised Electric Distribution Inspection Guidelines

1.3 Analysis surrounding the risk of assets (dependent on asset age, general health, geographic area, etc.) has been performed to garner a stronger understanding of which assets can benefit from inspections on risk-based timescales.

As PG&E embarks on this new, risk-based approach, the lower-risk area and/or assets may end up outside the GO required time-cycle. However, PG&E is following the GO 165 path to provide clear notification and ensure transparency with the Commission as necessary and appropriate.

1. This shift to a risk-based timescale is a departure from the established EDPM cycle. As a result, the inspection of some assets will have a **one-time interval of inspections exceeding five (5) years**; this will be done with deliberate attention to safety and risk – incorporating the risk of the potential longer duration between inspections in this transitional period.

2. Within a working year, System Inspections execution organization has flexibilty to bundle and shift inspection scope for efficiency opportunities or due to unforeseen challenges (such as inclement weather or access).

3. Any change to inspection scope that impacts system risk will require alignment with Asset Strategy

4. In alignment with bulletin TD-8999B-001, Safety Re-Assessments will be performed for all open WSIP EC tags flagged as Time-Dependent prior to 2020 Wildfire Season.

2 Modifications to Asset Selection and Inspection Frequency

2.1 Below is the updated risk-based inspection timeline **for OVERHEAD STRUCTURES ONLY,** based on the "1-N Circuit Risk Ranking" and updated circuit-based grouping of distribution structures into "Blocks"

HFTD Tier	Year 1	Year 2	Year 3	Year 4	Year 5
Tier 3 Blocks	All	TBD	TBD	TBD	TBD
Tier 2 Blocks	1/3	1/3	1/3	TBD	TBD
Non-HFTD Blocks	1/5	1/5	1/5	1/5	1/5

1. Based on the above table, the new inspection cycles will be:

   a. Tier 3 (T3) structures will be inspected every year.

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Revised Electric Distribution Inspection Guidelines

b. Tier 2 (T2) structures (that are not contained on a Tier 3 Block) will be inspected once every three years.

c. Non-HFTD structures (that are not contained on a Tier 2 or Tier 3 Block) will be inspected once every five years.

d. Risk analysis to define annual inspection scope will leverage actual inspection data to continue to refine a risk-based inspection cycle for "TBD" indicated years.

2.2 This ensures that higher risk structures will be inspected more frequently.

2.3 The above table does not impact underground inspection cycles; Underground assets are remaining on a 3-year detailed inspection cycle.

3 Modifications to Inspection Methods

3.1 *Inspection methods will not be modified (i.e. drone/helicopter) as a result of this bulletin.*

4 EDPM Definition Changes

4.1 Compelling Abnormal Condition is defined as being any electric distribution pole, equipment, component, conductors, vegetation or third party condition that cause a safety or fire ignition risk that may adversely impact public safety and/or service reliability **in the next five (5) years**.

DOCUMENT APPROVER

[redacted], Director, Electric Distribution Asset Strategy

DOCUMENT CONTACT

[redacted], Director, Electric Distribution Asset Strategy

INCLUSION PLAN

This bulletin will be added to TD-2305M located in the Technical Information Library. The bulletin content will be incorporated in the next revision of the EDPM.

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PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_124-Q015		
PG&E File Name:	GRC-2023-PhI_DR_TURN_124-Q015		
Request Date:	February 15, 2022	Requester DR No.:	TURN-PG&E-124
Date Sent:	March 10, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Katy Morsony

SUBJECT: PG&E-4, CHAPTER 10, OH AND UG ELECTRIC ASSET INSPECTIONS

QUESTION 015

Re. WP 10-7,

a. At lines 15 and 18, PG&E sets forth Unit Cost values that indicate the company expects forecasted unit costs to remain elevated relative to the average of the pre-WSIP, historical years (i.e., 2016-2018).

   Please list each factor (e.g., reliance upon contract work, more numerous photographs, new inspection techniques, inspection techniques that are used more frequently, more frequent pole climbs, more “minor work” units accomplished, etc.) that causes Unit Cost in 2023 to remain elevated. To the extent that the list of factors includes more “minor work” units accomplished, please identify the number of such units in each year, 2016-2021, with 2019 WSIP-related units separated from the rest of the 2019 units.

b. Please disaggregate the recorded (for 2019-2020) and forecasted (2021- 2023) annual Units between those that were/will be accomplished using the (i) routine, GO 165-based inspection approach and (ii) enhanced, WSIP-based inspection approach.

c. Please identify the number of Units in each year, 2019-2021 using the traditional inspection approach (i.e., with the pre-WSIP, asset-health criteria), disaggregated into (i) HFTD Tier 3 and Zone 1, (ii) HFTD Tier 2, and (iii) Non-HFTD (assumed to be Tier 1) areas.

d. Please identify the number of poles inspected in each year, 2019-2021 using the enhanced inspection approach (i.e., with the WSIP-related, asset health criteria), disaggregated into (i) HFTD Tier 3 and Zone 1, (ii) HFTD Tier 2, and (iii) Non-HFTD (assumed to be Tier 1) areas.

ANSWER 015

a. Drivers for higher unit cost beginning in 2020 include:
   - Moved away from manual, paper process where inspector was highlighting facilities on a map to record completion of an inspection, and inspections were managed at "plat map" level.
   - Beginning in 2020, inspection process now requires:
     - New maintenance plan (MP) structure with specific poles attached to the maintenance plan; new MPs were not plat-based, and not as efficient to schedule/complete in the field based on how they were structured. Example - previously had one MP for an entire plat map/grid; Inspector would complete all work within that grid. The new structure for that one plat map may now have multiple MPs for different HFTD designations, different circuits, etc., that are more difficult to schedule/bundle, and may include Inspectors visiting the same area on different cycles.
     - Inspections now performed using a mobile device, in the INSPECT application.
     - A completed OH inspection now requires that the Inspector fill out a detailed inspection questionnaire (checklist), with ~75 to 100 questions, as well as capturing additional information to help document attributes used for our inventory documentation and risk assessments.
     - A completed OH inspection now requires a minimum of 5 photos be taken.
     - Because all work is recorded in a mobile device, the device itself adds time to the process to load maps, submit work, etc., that did not exist in the paper process.

b. 2019: 489,692 units using traditional inspections approach
   2020: 704,502 units using enhanced inspections approach
   2021: 880,535 units using enhanced inspections approach
   2022: 882,202 units using enhanced inspections approach
   2023: 608,807 units using enhanced inspections approach

c. PG&E completed a total of 489,692 traditional overhead (OH) inspections in 2019. The GO 165 OH inspections were being performed on a map-based level and were not tracked as individual assets by HFTD categories. PG&E pivoted its inspection approach starting in 2020 where all GO 165 inspections are performed using the detailed “enhanced” inspection methods regardless of HFTD tier.

d. PG&E implemented enhanced inspections for GO 165 in 2020, so there were no enhanced inspections in 2019. See “GRC-2023-PhI_DR_TURN_124-Q015Atch01” for a breakdown of Overhead (OH) Inspections completed for years 2020 and 2021.

2020	
Category	**Overhead Inspections**
HFTD Buffer Zone	3,188
Non-HFTD	350,711
ZONE 1	524
HFTD - Tier 2	151,968
HFTD - Tier 3	198,111
Grand Total	**704,502**

2021	
Category	**Overhead Inspections**
HFTD Buffer Zone	6
Non-HFTD	428,557
ZONE 1	71,683
HFTD - Tier 2	232,313
HFTD - Tier 3	147,976
Grand Total	**880,535**

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
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Data Response

PG&E Data Request No.:	TURN_128-Q002		
PG&E File Name:	GRC-2023-PhI_DR_TURN_128-Q002		
Request Date:	February 17, 2022	Requester DR No.:	TURN-PG&E-128
Date Sent:	March 8, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Katy Morsony

SUBJECT: PG&E-4, CHAPTER 11

QUESTION 002

Re. WP 11-10 (MAT KAA), WP 11-18 (MAT KBA), WP 11-19 (MAT KBC), WP 11-20 (MAT KBP), WP 11-36 (MAT 2AA), WP 11-39 (MAT 2AE), and WP 11-40 (MAT 2AF), PG&E identifies the "Program inception to August 2020 average unit cost, escalated for inflation" as the basis for the respective unit-cost forecast (i.e., in the Unit Cost Forecast Basis lines on each of the referenced pages). With this in mind, please responds to the following for each of the referenced MAT codes:

a. What year and month was "Program inception"?

b. Why did PG&E use August 2020 as the cutoff for calculating unit costs?

c. Please provide an Excel-formatted workpaper containing the unit-cost forecast calculation, analogous to the one that PG&E provided to Cal Advocates for MAT 2AC the response to Cal Advocates DR 90-3, but including data for 2020 (both for the entire year and through August) in the calculation instead of limiting it to pre-2020 data as requested by Cal Advocates. (Please provide the information in an Excel-formatted spreadsheet, and, to the extent that the MAT-specific program-inception year for any of the MAT codes requested in the instant request is different than the one for MAT 2AC, please use the relevant inception year.)

ANSWER 002

a. PG&E used recorded data going back to 2016 when developing the unit cost forecast basis for these MAT codes. PG&E will update its workpapers to correctly describe its unit cost forecast methodology in a future errata submission.

b. PG&E used August 2020 as the cutoff for calculating unit costs based on the timing of forecast development for the 2023 GRC.

c. See "GRC-2023-PhI_DR_TURN_128-Q002Atch01" for recorded data of MAT codes requested.

MAT		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
2AA	Total (Actual $)	38,487,145	57,789,593	50,033,400	76,346,478	55,440,592	56,246,191	49,381,991	55,881,815	94,998,503	227,751,394	179,383,441	**941,740,543**
	Total (Escalated to 2020)	54,208,179	78,114,388	64,842,105	95,597,327	67,007,720	65,937,342	56,533,641	62,967,313	103,624,177	240,960,975	179,383,441	**1,069,176,607**
	Units	7,343	10,516	10,189	14,410	9,834	10,424	10,112	11,394	14,650	21,134	14,179	**134,185**
	Unit Cost	7,382	7,428	6,364	6,634	6,814	6,326	5,591	5,526	7,073	11,402	12,651	
2AE	Total (Actual $)	10,710,807	17,231,879	22,434,203	16,828,036	17,766,398	22,786,567	28,136,236	25,933,655	37,742,618	34,864,697	44,510,020	**278,945,114**
	Total (Escalated to 2020)	15,085,904	23,292,389	29,074,197	21,071,244	21,473,180	26,712,665	32,211,011	29,221,895	41,169,572	36,886,849	44,510,020	**320,708,925**
	Units	701	995	1,316	984	940	1,288	1,541	1,248	1,458	1,205	1,094	**12,770**
	Unit Cost	21,521	23,409	22,093	21,414	22,844	20,740	20,903	23,415	28,237	30,611	40,686	
2AF	Total (Actual $)	18,981	57,863	226,783	2,556,007	1,648,034	2,533,954	3,281,935	3,659,461	6,343,345	10,850,754	4,980,506	**36,157,624**
	Total (Escalated to 2020)	26,735	78,213	293,905	3,200,507	1,991,880	2,970,551	3,757,235	4,123,460	6,919,308	11,480,098	4,980,506	**39,822,399**
	Units	1	7	38	659	362	557	688	1,047	1,457	1,649	697	**7,162**
	Unit Cost	26,735	11,173	7,734	4,857	5,502	5,333	5,461	3,938	4,749	6,962	7,146	
KAA	Total (Actual $)	14,734,978	19,787,725	23,803,600	31,761,846	17,673,470	23,819,264	13,599,739	16,272,789	21,269,903	87,222,002	97,716,728	**367,662,042**
	Total (Escalated to 2020)	20,753,846	26,747,134	30,848,903	39,770,630	21,360,864	27,923,294	15,569,294	18,336,087	23,201,167	92,280,878	97,716,728	**414,508,826**
	Units	11,026	14,144	20,214	24,499	12,361	18,844	20,943	26,886	28,797	48,615	43,736	**270,065**
	Unit Cost	1,882	1,891	1,526	1,623	1,728	1,482	743	682	806	1,898	2,234	
KBA	Total (Actual $)	10,516,793	14,583,549	19,443,445	25,800,310	20,539,046	18,864,826	11,426,823	11,857,411	15,497,897	15,233,742	11,881,331	**175,645,173**
	Total (Escalated to 2020)	14,812,640	19,712,632	25,198,245	32,305,887	24,824,314	22,115,213	13,081,691	13,360,863	16,905,075	16,117,299	11,881,331	**210,315,189**
	Units	4,924	6,148	7,272	9,563	7,268	7,092	7,502	7,165	7,371	6,067	4,839	**75,211**
	Unit Cost	3,008	3,206	3,465	3,378	3,416	3,118	1,744	1,865	2,293	2,657	2,455	
KBC	Total (Actual $)	2,176,972	2,279,571	2,387,322	3,980,500	3,998,703	3,256,080	1,748,202	635,142	653,910	1,016,718	929,323	**23,062,443**
	Total (Escalated to 2020)	3,066,211	3,081,304	3,093,912	4,984,188	4,832,993	3,817,099	2,001,382	715,674	713,283	1,075,688	929,323	**28,311,057**
	Units	424	519	449	563	541	465	534	222	155	137	163	**4,172**
	Unit Cost	7,232	5,937	6,891	8,853	8,933	8,209	3,748	3,224	4,602	7,852	5,701	
KBP	Total (Actual $)	178,252	1,126,328	1,064,059	1,409,507	664,655	60,597	1,035,023	491,413	515,476	135,586	38,732	**6,719,628**
	Total (Escalated to 2020)	251,064	1,522,461	1,378,996	1,764,915	803,328	71,038	1,184,918	553,722	562,280	143,450	38,732	**8,274,904**
	Units	9	198	44	27	49	31	4,895	3,540	2,598	869	259	**12,519**
	Unit Cost	27,896	7,689	31,341	65,367	16,394	2,292	242	156	216	165	150	

PACIFIC GAS AND ELECTRIC COMPANY
2023 General Rate Case Phase I
Application 21-06-021
Data Response

PG&E Data Request No.:	TURN_128-Q003		
PG&E File Name:	GRC-2023-PhI_DR_TURN_128-Q003		
Request Date:	February 17, 2022	Requester DR No.:	TURN-PG&E-128
Date Sent:	March 4, 2022	Requesting Party:	The Utility Reform Network
PG&E Witness:	Mark Esguerra	Requester:	Katy Morsony

SUBJECT: PG&E-4, CHAPTER 11

QUESTION 003

Re. WP 11-10 (MAT KAA), WP 11-11 (MAT KAC), WP 11-12 (MAT KAD),WP 11-36 (MAT 2AA), WP 11-37 (MAT 2AB), WP 11-39 (MAT 2AE), WP 11-40 (MAT 2AF), and WP 11-37 (MAT 2AB), please responds to the following for each of the referenced MAT codes:

a. The 2018 Unit Cost for these overhead activities is generally significantly higher than the Unit Cost for 2017. What beyond escalation is PG&E's understanding of the specific cause(s) of the significant increase to unit costs between 2017 and 2018 for the referenced MAT codes for which such is the case?

b. To the extent that the reasons identified in response to section (a) for any of the MAT codes includes contract-cost escalation and/or additional overtime, what is driving the increase to such costs and why does PG&E believe that such costs will not decline by 2023?

c. The 2019 Unit Cost for these overhead activities is generally significantly higher than the Unit Cost for 2018. What beyond escalation is PG&E's understanding of the specific cause(s) of the significant increase to unit costs between 2018 and 2019 for the referenced MAT codes for which such is the case?

d. To the extent that the reasons identified in response to section (c) for any of the MAT codes include contract-cost escalation and/or additional overtime, what is driving the increase to such costs and why does PG&E&E believe that such costs will not decline by 2023?

e. The 2020 Unit Cost for many of these overhead activities is generally significantly higher than the Unit Cost for 2019. What beyond escalation is PG&E's understanding of the specific cause(s) of the significant increase to unit costs between 2019 and 2020 for the referenced MAT codes for which such is the case?

f. To the extent that the reasons identified in response to section (e) for any of the MAT codes include contract-cost escalation and/or additional overtime, what is driving the increase to such costs and why does PG&E believe that such costs will not decline by 2023?

ANSWER 003

a. Costs for overhead notifications increased starting in 2018 to allow PG&E to complete rescheduled Priority F notifications. Work starting in 2018 also focused on higher priority work related to major emergencies, including northern California wildfires, which resulted in higher costs due to increased use of contract labor.

b. There are a number of factors that can influence unit costs between 2017 and 2023. For the most part, the unit costs in PG&E's forecast for the MATs identified in part (a) remain relatively steady from the 2020 base year through the 2023 test year.

c. In 2019 and 2020, PG&E implemented its Wildfire Safety Inspection Program (WSIP). It used all available resources to conduct inspections of poles and associated equipment in the HFTD areas on an accelerated and enhanced basis to mitigate the risk of initiating fires. The WSIP led to a significant increase in the volume of Electric Corrective (EC) notifications, including EC notifications that needed to be addressed within three months of the identification date. This higher volume required more contractor and overtime resources to complete the notifications.

d. See response to 3b.

e. See response to 3c.

f. See response to 3b.