
PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION PLAN REPORT
RULEMAKING 18-10-007
UPDATED
MARCH 17, 2020



Updates to Pacific Gas and Electric Company's 2020 Wildfire Mitigation Plan

Pacific Gas and Electric Company (PG&E) hereby provides notice that it has identified updates to the 2020 Wildfire Mitigation Plan (2020 WMP), filed February 7, 2020. The updates to the 2020 WMP are described below and have been posted to the PG&E Wildfire Mitigation Plan website [PGE.com/2020WMP](https://www.pge.com/2020WMP) (WMP Website).

PG&E is providing updates to the 2020 WMP and to Attachment 1 to the 2020 WMP, which included all of the tables required by the WMP Guidelines (Attachment 1).

The tables below summarize the changes made to the updated documents. Table 1 summarizes changes to the 2020 WMP; location of the change, the original text, and a redline version of the update. In cases where the update could not easily be shown in this table format, the update is described. For example, the update p. 4-7, Figure PG&E 4-1 is a page sized chart which was not practical to show in redline form in the Table 1 format.

Table 2 below provides a summary of updates to Attachment 1, Tables 1 – 31. Because it is not practical to show entire tables in a summary table format, the summaries are descriptions rather than a redline format. Understanding that stakeholders may want to compare the old tables to the updated tables, PG&E has retained a copy of the original version of Attachment 1 on the WMP Website called "Original Attachment 1: All Tables Required by the WMP Guidelines." In cases where updates are to tables that are in both the 2020 WMP and Attachment 1 the update is noted in both Table 1 and Table 2 below.

Table 1: Summary of Updates to the WMP

Location	Original	Update (with redlines)
Executive Summary p.5	The vegetation inspection process entails ground patrols and the use of Light Detection and Ranging and advanced analysis techniques to identify dead and risky trees that are too close to utility facilities.	The vegetation inspection process entails ground patrols and the use of Light Detection and Ranging and advanced analysis techniques to identify <u>trees that pose a strike risk to</u> that are too close to utility facilities. -
p. 2-5, Table 1	N/A Table being replaced	Add section numbers 2-4 to Table 1-1 and add a comments column. Add comments below table 1-1.
p. 2-28, Table 4, third cell in the "Underlying Assumptions" column	Reduce wildfire through (1) overhand clearing 4ft vertical from conductor to sky,	Reduce wildfire through (1) overhand clearing 4ft vertical from conductor to sky, <u>for particular trees,</u>

p. 2-20, second and third bullets	<ul style="list-style-type: none">• Items 8.a., 8.b., 9.a, and 9.b. - PG&E is providing in the above table data for 2015 through 2019 for wildfires that CAL FIRE concluded were caused by PG&E equipment. The “structures damaged”	<ul style="list-style-type: none">• Items 8.a., 8.b., 9.a, and 9.b. PG&E is providing in the above table data for 2015 through 2019 for wildfires that CAL FIRE concluded were caused by PG&E equipment. The “structures damaged” metric represents the count of structures destroyed from
-----------------------------------	--	---

Location	Original	Update (with redlines)
	<p>metric represents the count of structures destroyed from incidents listed on CAL FIRE's website that can be linked to a fire ignition in PG&E's fire incident report.</p> <ul style="list-style-type: none"> • Item 10 - The 2015 through 2018 ignition data is primarily based on fire incident reports filed with the CPUC annually in accordance with D.14-02-015. These reports include fire incidents that may be associated with PG&E facilities and meet the following conditions: (1) a self-propagating fire of material other than electrical and/or communication facilities (2) the resulting fire traveled greater than one linear meter from the ignition point, and (3) PG&E has knowledge that the fire occurred. Where not already included as part of the CPUC fire incidents report data, PG&E also included data for 2015 through 2018 wildfires that CAL FIRE concluded were caused by PG&E equipment. As of the time of the 2020 WMP filing, 2019 ignition data is being reviewed by PG&E in preparation for its 2019 fire incident that will be submitted by April 1, 2020 per CPUC Decision D.14-02-015. The 2019 data in 	<p>incidents listed on CAL FIRE's website that can be linked to a fire ignition in PG&E's fire incident report.</p> <ul style="list-style-type: none"> • Item 10 – The 2015 through 2018 ignition data is primarily based on fire incident reports filed with the CPUC annually in accordance with D.14-02-015. These reports include fire incidents that may be associated with PG&E facilities and meet the following conditions: (1) a self-propagating fire of material other than electrical and/or communication facilities (2) the resulting fire traveled greater than one linear meter from the ignition point, and (3) PG&E has knowledge that the fire occurred. Where not already included as part of the CPUC fire incidents report data, PG&E also included data for 2015 through 2018 wildfires that CAL FIRE concluded were caused by PG&E equipment. As of the time of the 2020 WMP filing, 2019 ignition data is being reviewed by PG&E in preparation for its 2019 fire incident that will be submitted by April 1, 2020 per CPUC Decision D.14-02-015. The 2019 data in this table is preliminary and may be revised by the time that report is submitted. • Items 8.a., 8.b., 9.a, 9.b., and 10 The 2015 through 2018 ignition data is primarily based on fire incident reports filed with the CPUC annually in accordance with D.14-02-015. These reports include fire incidents that may be associated with PG&E facilities

Location	Original	Update (with redlines)
	this table is preliminary and may be revised by the time that report is submitted.	<p>and meet the following conditions:</p> <p>(1) a self-propagating fire of material other than electrical and/or communication facilities</p> <p>(2) the resulting fire traveled greater than one linear meter from the ignition point, and (3) PG&E has knowledge that the fire occurred. Where not already included as part of the CPUC fire incident report data, PG&E also included data for 2015 through 2018 wildfires that CAL FIRE concluded were caused by PG&E equipment and 2019 wildfires that CAL FIRE is currently investigating where the point of ignition may be located near PG&E overhead electric facilities. As of the time of the 2020 WMP filing, 2019 ignition data is being reviewed by PG&E in preparation for its 2019 fire incident report that will be submitted by April 1, 2020 per D.14-02-015. The 2019 data in this table is preliminary and may be revised by the time that report is submitted.</p>

p. 3-11, Table 11-2: KEY RECENT DRIVERS OF IGNITION PROBABILITY, LAST 5 YEARS – TRANSMISSION SYSTEM (CONTINUED)	Transformer: number of incidents for 2019 = 5	Transformer: number of incidents for 2019 = 3
p. 4-7, Figure PG&E 4-1	N/A Figure being replaced	Figure Update: “Outcome Type” fields have been updated; edit made to the bowtie visual so it accurately represents the safety consequences accounted for in the case of small and large fire outcomes in the Wildfire Risk Model.
p. 5-24, Section 5.1.D.3.17	5.1.D.3.17 Sensor IQ Type: New Technology (Commercially Available Offering) Description: Itron/SSN is being contracted to implement Sensor IQ, which allows for a parallel, more granular data path (outside of	5.1.D.3.17 Sensor IQ Type: New Technology (Commercially Available Offering) Description: Itron/SSN is being contracted to implement Sensor IQ, which allows for a

Location	Original	Update (with redlines)
	<p>billing) to support distribution asset analytics use cases. Deployment enables customizable Network Interface Card (NIC) data sampling, read jobs, and alarms. The scope includes implementing Sensor IQ to all SmartMeters in HFTD areas and customizing reads and alarms to identify service transformer failures, with other use-cases to be considered based on wildfire risk reduction and/or business value. The data collected through Sensor IQ is critical for a variety of other wildfire related initiatives, including:</p> <p>(i) Rapid Earth Fault Current Limiter which requires feeder phasing to determine the line-earth capacitive imbalance; and (ii) increasing the data collected (voltage, current, power factor) and increasing the frequency of data collection will improve wires down algorithms to find faults.</p>	<p>parallel, more granular data path (outside of billing) to support distribution asset analytics use cases. Deployment enables customizable Network Interface Card (NIC) data sampling, read jobs, and alarms. The scope includes implementing Sensor IQ to all SmartMeters in HFTD areas and customizing reads and alarms to identify service transformer failures, with other use-cases to be considered based on wildfire risk reduction and/or business value. The data collected through Sensor IQ is critical for a variety of other wildfire related initiatives, including: (i) Rapid Earth Fault Current Limiter which requires feeder phasing to determine the line-earth capacitive imbalance; and (ii) increasing the data collected (voltage, current, power factor) and increasing the frequency of data collection will improve wires down algorithms to find faults.</p>
p. 5-94, Section 5.3.2.2.6	<p>PG&E is piloting Sensor IQ on approximately 500K SmartMeters™ in HFTD areas and customizing reads and alarms to identify service transformer failures, with other use-cases to be considered based on wildfire risk reduction and/or business value. The data collected through Sensor IQ is critical for a variety of other wildfire related</p>	<p>PG&E is piloting Sensor IQ on approximately 500K SmartMeters™ in HFTD areas and customizing reads and alarms to identify service transformer failures, with other use-cases to be considered based on wildfire risk reduction and/or business value. SSN is being contracted to implement Sensor IQ, which allows for a parallel, more granular data path (outside of billing) to support distribution asset analytics use cases. Deployment enables</p>

Location	Original	Update (with redlines)
	initiatives, including: (i) Rapid Earth Fault Current Limiter which requires feeder phasing to determine the line-earth capacitive imbalance; (ii) increasing the data collected (voltage, current, power factor) and increasing the frequency of data collection will improve wires down algorithms to find faults.	customizable Network Interface Card (NIC) data sampling, read jobs, and alarms. The data collected through Sensor IQ is critical for a variety of other wildfire related initiatives, including: (i) Rapid Earth Fault Current Limiter which requires feeder phasing to determine the line-earth capacitive imbalance; (ii) increasing the data collected (voltage, current, power factor) and increasing the frequency of data collection will improve wires down algorithms to find faults.
p. 5-35, first sentence under Alternatives Analysis	“January 15, 2019”	“January 15, 2019 -2020”
P 5-38, last sentence of first paragraph	These Non-Wildfire Programs are identified as “existing” programs on the Section 5.3 charts, even though 2020 costs are awaiting resolution of PG&E’s 2020 GRC, because historical costs of these programs have been authorized in prior GRC decisions.	These -Non-Wildfire Programs are identified as “existing” programs on the Section 5.3 charts, even though 2020 costs are awaiting resolution of PG&E’s 2020 GRC, because historical costs of these programs have been authorized in prior GRC decisions.
p. 5-38, last sentence	“Table 21”	“ Table 21 Tables 21-30”
p. 5-40, before last sentence in the Overview section	N/A - new language to be added	“See Attachment 1, Table 21 for the additional information associated with the initiatives discussed in the section”
p. 5-91, Section 5.3.2.2.3, second to last sentence in first paragraph	“Tier 2 and Tier 2 HFTD”	“Tier 2 and Tier 2 -3 HFTD”
p. 5-97, Section 5.3.2.3.2	PG&E does not have a program to install addition	PG&E does not have a program to install additional fault indicators in fire areas for future years.

Location	Original	Update (with redlines)
	fault indicators in fire areas for future years.	
p. 5-122, Transmission Line Assessments, second paragraph	Prior to next fire season, PG&E will be evaluating all 552 transmission lines in HFTD areas to determine which lines can be removed from future PSPS Event scope via: supplemental inspections (ultrasonic), below-grade inspections and repairs, increased Vegetation Management (i.e. expanded Rights Of Way), accelerated repairs or replacement of assets.”	Prior to next fire season, PG&E will be evaluating all 552 transmission lines in HFTD areas to determine which lines can be removed from future PSPS Event scope. via: supplemental inspections (ultrasonic); below-grade inspections and repairs; increased Vegetation Management (i.e. expanded Rights Of Way); accelerated repairs or replacement of assets.”
p. 5-150, new section	N/A – new language to be added	<p>“5.3.3.18.3 – Building and Sourcing Services</p> <p>Building services supports the WMP initiatives in two primary ways: (1) securing office space for employees and contractors supporting the WMP initiatives; and (2) securing yards and staging areas for materials needed to complete WMP work.</p> <p>Sourcing provides strategic, operational, and execution level support of PG&E’s WMP. Sourcing provides sourcing program management support, develops project plans, and coordinates sourcing activities with cross functional teams. Sourcing support includes but is not limited to facilitating supplier evaluations, contract bidding and bid awards processes, and direct negotiations.</p> <p>Placement in Section 5.3.3 is based on the desire to put these services within the Section 5.3 initiatives, but note the</p>

Location	Original	Update (with redlines)
		services support all the WMP initiatives.”
p. 5-165, Section 5.3.4.9, add to end of first paragraph	N/A- new language to be added	“Ultrasonic inspection is included in the details and data associated with Attachment 1, Table 24 Section 12, Patrol inspections of transmission electric lines and equipment.”
p. 176, bullet at bottom of page, Overhand Trimming	Removing overhanging branches and limbs four feet out from the lines and up to the sky around electric power lines required by regulatory requirements to further reduce the possibility of wildfire ignitions and/or downed wires and outages due to vegetation-conductor contact.	Removing overhanging branches and limbs four feet out from the lines and up to the sky for particular trees around electric power lines required by regulatory requirements to further reduce the possibility of wildfire ignitions and/or downed wires and outages due to vegetation-conductor contact.
p. 5-177, Section 3.	For example, instead of the required four feet radial clearance around conductors, PG&E is trimming trees from the conductor to sky for overhang clearing.	For example, instead of the required four feet radial clearance around conductors, PG&E is trimming trees from the conductor to sky for overhang clearing on particular trees.
p. 5-177, section 5.3.5 Subsection 1, paragraph 1	This includes coordinating with cities, counties and other local authorities to obtain local encroachment permits or to manage other local requirements such as heritage tree requirements.	This includes coordinating with cities, counties and other local authorities to obtain local encroachment permits or to manage other local requirements.
5-180, 5.3.5.1 paragraph 1	PG&E proactively communicates to and partners with land owners, government agencies and community organizations on the work we are planning in and around their neighborhood	PG&E proactively communicates to and partners with land owners, government agencies and community organizations on the work we are planning.
5-180, 5.3.5.1 paragraph 2	The performance of vegetation management work could create environmental impacts as well, which PG&E is careful to mitigate, monitor, and manage. PG&E	The performance of vegetation management work could create environmental impacts as well, which PG&E is careful to mitigate, monitor, and manage. PG&E vegetation management contractors are trained

Deleted: such as heritage tree requirements.

Deleted: in and around their neighborhood

	vegetation management contractors are trained on Best Management Practices and Avoidance and Minimization Measures to manage erosion, prevent impacts to sensitive environmental resources (e.g., bird nests, sensitive species and habitats) and protect waterways.	on Best Management Practices and Avoidance and Minimization Measures <u>to help prevent impacts to sensitive environmental resources and protect waterways.</u>
5-180, 5.3.5.1 paragraph 4	PG&E also coordinates with numerous cities, counties, and other local authorities to obtain local encroachment permits or to manage other local requirements, such as heritage tree ordinances.	PG&E also coordinates with numerous cities, counties, and other local authorities to obtain local encroachment permits or to manage other local requirements.
5-186, 5.3.5.4 paragraph 1	Trees can also be flagged for immediate follow-up work, while trees that require work but show no near-term risk factors are scheduled following the standard process. The same process would be followed during any urgent conditions, as long as conditions are safe enough for the tree crews to work in.	Trees can also be flagged for <u>urgent</u> follow-up work, while trees that require work but show no near-term risk factors are scheduled following the standard process. The same process would be followed during any urgent conditions, as long as conditions are safe enough for the tree crews to work in.
5-190 5.3.5.9 paragraph 1	Further, in Wildland-Urban Interface (WUI) inspections are performed as frequently as quarterly, so 3 additional inspections in a year on top of the routine program's once-annual inspection.	Further, in Wildland-Urban-Interface (WUI) inspections are performed as frequently as quarterly, so 3 additional inspections in a year on top of the routine program's once-annual inspection.
5-190 5.3.5.9 paragraph 2	PG&E will also inspect for and remove incidental vegetation that restricts access for safe and efficient removal of dead and dying trees may also be removed.	PG&E will also inspect for and remove incidental vegetation that restricts access for safe and efficient removal of dead and dying trees may also be removed.
5-196 5.3.5.15		
p. 5-217, footnote 27	"Rulemaking 18-12-025"	"Rulemaking 18-12- 025 005"

Deleted: , such as heritage tree ordinances

Deleted: immediate

p. 5-241, first paragraph, last sentence	This is done through statistically significant research studies, as well as surveys, customer feedback and input from CBOs, and by tracking customer engagement including web traffic, click-through-rates of advertisements and conversion rates / actions taken by customers as a result. PG&E will adjust as needed to ensure the effective use of available outreach channels.	This is done through multiple sources of direct customer feedback including, but not limited to: opinion surveys, interviews with CBOs, and tracking customer engagement through web traffic (e.g. click-through-rates of advertisements, conversion rates, etc.), and actions taken by customers as a result. PG&E will adjust as needed to ensure the effective use of available outreach channels. With customer surveys, PG&E will compare the responses of various groups (e.g. residential vs. non-residential). Where we have 95% confidence those
--	--	---

Location	Original	Update (with redlines)
		differences in response are due to actual underlying differences and not chance, we will note those differences as being "statistically significant."
p. 5-190, Section 5.3.5.9	"Further, in Wildland-Urban Interface (WUI) inspections are performed as frequently as quarterly, so 3 additional inspections in a year on top of the routine program's once-annual inspection."	"Further, in Wildland-Urban Interface (WUI) inspections are performed as frequently as quarterly, so 3 additional inspections in a year on top of the routine program's once-annual inspection."
p. 5-190, Section 5.3.5.9	"PG&E will also inspect for and remove incidental vegetation that restricts access for safe and efficient removal of dead and dying trees may also be removed."	"PG&E will also inspect for and remove incidental vegetation that restricts access for safe and efficient removal of dead and dying trees may also be removed."
p. 5-196, Section 5.3.5.15	"In addition to establishing "new" miles that have been treated with EVM, PG&E will perform annual, follow-up vegetation maintenance work on the sections of line where EVM was previously established to remove overhangs and to keep branches above powerline height from growing back into an overhanging position. As the number of miles initially worked to remove overhangs increases, the annual maintenance and upkeep effort will also grow along with the continued removal of hazard trees as outlined above."	"In addition to establishing "new" miles that have been treated with EVM, PG&E will perform annual, follow-up vegetation maintenance work on the sections of line where EVM was previously established to remove overhangs and to keep branches above powerline height from growing back into an overhanging position. As the number of miles initially worked to remove overhangs increases, the annual maintenance and upkeep effort will also grow along with the continued removal of hazard trees as outlined above."
p. 5-240, third bullet	Direct Mail/Print Media Engagement:	Direct Mail/Print Media Engagement: Add Footnote 1: See Table 30 Section 5-1 for details regarding PSPS and

Location	Original	Update (with redlines)
		emergency preparedness media education campaigns
p. 5-247, Section 5.3.9.7.1	N/A- new language to be added	“In addition to contractor resources and Mutual Assistance agreements, PG&E owns and maintains aviation resources. The 2020 – 2022 aviation operations and maintenance expense forecast in Table 29, Section 7 was determined by forecasting total operation and maintenance expenses, less forecast chargebacks and forecast reimbursements from CAL FIRE for utilizing PG&E helicopters.”

Table 2: Summary of Updates to Attachment 1, Tables 1 - 31

Location: Table, Section	Description of Change
Table 1; Table 1-1 (Distribution)	Add Sections 2-4 to Table 1-1, add comments column, add comments below Table 1-1.
Table 4, eighth cell in the column “Underlying assumptions”	Edit to the language describing the underlying assumptions.
Table 13	Data updated using an improved database query methodology that provides a more accurate estimate of the number of electric PG&E customers located in each Fire Threat District category. Most of the data in the table has been updated.
Table 22, Section 2-5	Update to new/existing information.
Table 22, Section 7-2	Correction to line miles and spend/treated line mile; line miles should be N/A for all years and spend/treated line mile should be \$0 for

Location: Table, Section	Description of Change
	all years. Updated memorandum account information.
Table 23, Section 2-3	Update to the proceeding and memorandum account information.
Table 23, Section 5	Update comment/reference.
Table 23, Section 8-6	Add the word Substation to the end of the Initiative Activity title. Updates to the Ignition probability drivers targeted, Risk reductions, Risk-spend efficiency, and Other risk drivers addressed.
Table 23, Section 12-1	Remove the words “combined mitigation and control” from the Initiative Activity title.
Table 23, Section 12-2	Remove the words “combined mitigation and control” from the Initiative Activity title.
Table 23, Section 12-4	Updated all rows to reflect attachment: WSD_002-Q46-PGE-43895-E-385-Atch01
Table 23, Section 18	Add new set of rows, “Other/not listed, Building and Sourcing Services-Transmission and Distribution”
Table 24, Section 1	Update to Costs, spend/treated line mile and memorandum account information.
Table 24, Section 2	Update to Costs, spend/treated line mile.
Table 24, Section 9	Details provided are duplicative to Table 24 Section 15-2. Delete data from Table 24 Section 9 and add new comment.
Table 24, Section 10	Details provided are duplicative to Table 24 Section 15-1. Delete data from Table 24 Section 10 and add new comment.
Table 24, Section 11	Update Costs due to mathematical error and update spend/treated line mile.

Table 24, Section 15-1	Update Costs and In/exceeding compliance with regulations
Table 26, Section 5-3	Update all rows to reflect attachment: WSD_002-Q46-PGE-43895-E-385-Atch01

Location: Table, Section	Description of Change
Table 24, Section 15-2	Update Costs and In/exceeding compliance with regulations
Table 25, Section 5	Update to Ignition probability drivers targeted, Risk reductions, Risk-spend efficiency, and Other risk drivers addressed.
Table 25, Section 7-1	Update to Ignition probability drivers targeted, Risk reductions, Risk-spend efficiency, and Other risk drivers addressed.
Table 26, Section 3	Revise rows with new data and details.
Table 26, Section 4-1	Update to Ignition probability drivers targeted, Risk reductions, Risk-spend efficiency, and Other risk drivers addressed.
Table 26, Section 4-2	Update to Ignition probability drivers targeted, Risk reductions, Risk-spend efficiency, and Other risk drivers addressed.
Table 26, Section 5-2	Update to Ignition probability drivers targeted, Risk reductions, Risk-spend efficiency, and Other risk drivers addressed.
Table 26, Section 5-3	Update to Ignition probability drivers targeted, Risk reductions, Risk-spend efficiency, and Other risk drivers addressed.
Table 29, Section 2	Revise comment.
Table 29, Section 7	Add new set of rows, Other/not listed – Aviation Support
Table 30, Section 4	Update rows to include details for “Forest service and fuel reduction cooperation and joint roadmap”.
Table 30, Section 5-1	Add new set of rows, “Other/not listed, Emergency preparedness education campaign”

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

Executive Summary	1
1 Persons Responsible for Executing the WMP	1-1
1.1 Explanation of Data and Formatting	1-3
2 Metrics and Underlying Data	2-1
2.1 Lessons Learned: How Tracking Metrics on the 2019 Plan Has Informed the 2020 Plan	2-1
2.2 Recent Performance on Progress Metrics, Last 5 Years	2-4
2.3 Recent Performance on Outcome Metrics, Annual and Normalized for Weather, Last 5 Years	2-8
2.4 Description of Additional Metrics	2-20
2.5 Description of Program Targets	2-26
2.6 Detailed Information Supporting Outcome Metrics	2-30
2.7 Mapping Recent, Modelled, and Baseline Conditions	2-39
3 Baseline Ignition Probability and Wildfire Risk Exposure	3-1
3.1 Recent Weather Patterns, Last 5 Years	3-1
3.2 Recent Drivers of Ignition Probability, Last 5 Years	3-4
3.3 Recent Use of PSPS, Last 5 years	3-13
3.4 Baseline State of Equipment and Wildfire and PSPS Event Risk Reduction Plans	3-15
3.4.1 Current Baseline State of Service Territory and Utility Equipment	3-15
3.4.2 Planned Additions, Removal, and Upgrade of Utility Equipment by End of 3-Year Plan Term	3-24
3.4.3 Status Quo Ignition Probability Drivers by Service Territory	3-29
4. Inputs to the Plan and Directional Vision for Wildfire Risk Exposure	4-1
4.1 The Objectives of the Plan	4-1

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

4.2 Understanding Major Trends Impacting Ignition Probability and Wildfire Consequence	4-3
4.2.A – Contribution of Weather to Ignition Probability and Estimated Wildfire Consequences	4-10
4.2.B – Contribution of Fuel Conditions	4-13
4.2.1 Service Territory Fire-Threat Evaluation and Ignition Risk Trends	4-13
4.3 Change in Ignition Probability Drivers	4-22
4.4 Directional Vision for Necessity of PSPS	4-23
5 Wildfire Mitigation Strategy and Programs for 2019 and for Each Year of the 3-Year WMP Term	5-1
5.1 Wildfire Mitigation Strategy	5-1
5.1.A – PG&E's Approach to Managing Wildfire Risk	5-4
5.1.B – Major Investments and Implementation of Wildfire Mitigation Initiatives	5-5
5.1.C – Challenges Associated with Limited Resources	5-8
5.1.D – New or Emerging Technologies	5-9
5.1.D.1 Impact on Strategies	5-10
5.1.D.2 Implementation Approach and Integration of Emerging Technologies – Electric Program Investment Charge.....	5-12
5.1.D.3 New or Emerging Technologies – Project Summaries	5-13
5.1.D.3.1 Wildfire Spread Models	5-15
5.1.D.3.2 Satellite Fire Detection	5-15
5.1.D.3.3 Weather Model and Fire Potential Index – 2019 Model Expansions	5-15
5.1.D.3.4 SmartMeter™ Partial Voltage Detection (Formerly Known as Enhanced Wires Down Detection).....	5-17

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

5.1.D.3.5 Line Sensor Devices	5-17
5.1.D.3.6 Proactive Wires Down Mitigation Demonstration Project	5-17
5.1.D.3.7 Distribution, Transmission, and Substation – Fire Action Schemes and Technology (DTS-FAST).....	5-18
5.1.D.3.8 Remote Grid.....	5-19
5.1.D.3.9 Multi-Use Microgrid	5-20
5.1.D.3.10 Enhanced Asset Inspections – Drone/AI (Sherlock & Waldo)	5-21
5.1.D.3.11 Ultrasonic Technology.....	5-21
5.1.D.3.12 Below Ground Inspection of Steel Structures	5-22
5.1.D.3.13 Mobile LiDAR for Distribution Inspections	5-23
5.1.D.3.14 Transformer Monitoring.....	5-23
5.1.D.3.15 Maintenance Analytics	5-24
5.1.D.3.16 System Harmonics for Power Quality Investigation	5-24
5.1.D.3.17 (Omitted)	
5.1.D.3.18 Wind Loading Assessments	5-25
5.1.D.3.19 Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors (Distribution Fault Anticipation Technology)	5-25
5.1.D.3.20 Advanced Distribution Energy Resource Management System	5-25
5.1.D.3.21 Advanced Distribution Management System (ADMS)	5-26
5.2 Wildfire Mitigation Plan implementation	5-28
5.2.A Monitor and Audit WMP Implementation	5-28
5.2.B WMP Deficiencies	5-29
5.2.C Monitor and Audit Inspection Effectiveness.....	5-30
5.2.D Data Used for Wildfire-Related Decisions	5-31
5.3 Detailed Wildfire Mitigation Programs	5-33
5.3.1 Risk Assessment and Mapping.....	5-39

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

5.3.1.1 A Summarized Risk Map Showing the Overall Ignition Probability and Estimated Wildfire Consequence Along Electric Lines and Equipment	5-43
5.3.1.2 Climate-Driven Risk Map and Modelling Based on Various Relevant Weather Scenarios	5-45
5.3.1.3 Ignition Probability Mapping Showing the Probability of Ignition Along the Electric Lines and Equipment	5-48
5.3.1.4 Initiative Mapping and Estimation of Wildfire and PSPS Risk-Reduction Impact.....	5-51
5.3.1.5 Match Drop Simulations Showing the Potential Wildfire Consequences of Ignitions that Occur Along the Electric Line and Equipment	5-52
5.3.1.6 Weather-Driven Risk Map and Modelling Based on Various Relevant Weather Scenarios	5-53
5.3.2 Situational Awareness and Forecasting.....	5-54
5.3.2.1 Advanced Weather Monitoring and Weather Stations	5-57
5.3.2.1.1 Weather Prediction Program Using High Performance Cloud Computing	5-60
5.3.2.1.2 Wildfire Spread Models.....	5-65
5.3.2.1.3 Weather Stations	5-68
5.3.2.1.4 Wildfire Cameras	5-72
5.3.2.1.5 PG&E Fire Detection and Alert System (FDAS)	5-74
5.3.2.1.6 Live Fuel Moisture Sampling.....	5-78
5.3.2.1.7 Addressing Weather Forecast Model Uncertainty.....	5-79
5.3.2.1.8 PG&E Lightning Detection Network (PLDN)	5-83
5.3.2.1.9 Information Sharing	5-85
5.3.2.1.10 Collaborative Efforts to Advance Fire Science	5-87

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

5.3.2.2 Continuous Monitoring Sensors	5-90
5.3.2.2.1 Electric Transmission.....	5-90
5.3.2.2.2 Electric Distribution	5-90
5.3.2.2.3 SmartMeter™ Partial Voltage Detection (Formerly Known as Enhanced Wires Down Detection)	5-91
5.3.2.2.4 Distribution Fault Anticipation Technology	5-92
5.3.2.2.5 Early Fault Detection	5-93
5.3.2.2.6 Sensor IQ	5-94
5.3.2.2.7 Line Sensor Devices.....	5-95
5.3.2.2.8 Distribution Arching Fault Signature Library.....	5-96
5.3.2.3 Fault Indicators for Detecting Faults on Electric Lines and Equipment	5-97
5.3.2.3.1 Electric Transmission.....	5-97
5.3.2.3.2 Electric Distribution	5-97
5.3.2.4 Forecast of a Fire Risk Index, Fire Potential Index, or Similar.....	5-98
5.3.2.5 Personnel Monitoring Areas of Electric Lines and Equipment in Elevated Fire Risk Conditions	5-103
5.3.2.5.1 Safety and Infrastructure Protection Team	5-103
5.3.2.5.2 Data Collection	5-104
5.3.2.6 Weather Forecasting and Estimating Impacts on Electric Lines and Equipment	5-106
5.3.2.7 [Other] Wildfire Safety Operations Center (WSOC)	5-110
5.3.3 Grid Design and System Hardening	5-111
5.3.3.1 Capacitor Maintenance and Replacement Program	5-114

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

5.3.3.2 Circuit Breaker Maintenance and Installation to De-Energize Lines	
Upon Detecting a Fault.....	5-115
5.3.3.3 Covered Conductor Installation.....	5-116
5.3.3.4 Covered Conductor Maintenance	5-117
5.3.3.5 Crossarm Maintenance, Repair, and Replacement	5-118
5.3.3.6 Distribution Pole Replacement and Reinforcement, Including With	
Composite Poles.....	5-119
5.3.3.7 Expulsion Fuse Replacement.....	5-121
5.3.3.8 Grid Topology Improvements to Mitigate or	
Reduce PSPS Events.....	5-122
5.3.3.9 Installation of System Automation Equipment	5-127
5.3.3.10 Maintenance, Repair, and Replacement of Connectors, Including	
Hotline Clamps	5-129
5.3.3.11 Mitigation of Impact on Customers and Other Residents Affected During	
PSPS Event	5-130
5.3.3.12 Other Corrective Action	5-131
5.3.3.13 Pole Loading Infrastructure Hardening and Replacement Program	
Based on Pole Loading Assessment Program	5-136
5.3.3.14 Transformers Maintenance and Replacement.....	5-136
5.3.3.15 Transmission Tower Maintenance and Replacement.....	5-137
5.3.3.16 Undergrounding of Electric Lines and/or Equipment.....	5-138
5.3.3.17 Updates to Grid Topology to Minimize Risk of	
Ignition in HFTDs	5-139
5.3.3.17.1 Distribution System Hardening.....	5-140
5.3.3.17.2 Transmission Line System Hardening	
Overview and Strategy.....	5-143

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

5.3.3.17.3 Relationship Between System Hardening and Enhanced Vegetation Management.....	5-146
5.3.3.17.4 Non-Exempt Surge Arrester Replacement Program.....	5-146
5.3.3.17.5 Transmission Line System Hardening Overview and Strategy	5-147
5.3.3.18 Other/Not Listed [Only if an Initiative Cannot Feasibly Be Classified Within Those Listed Above].....	5-148
5.3.3.18.1 Evaluation New Protection Technologies	5-148
5.3.3.18.2 : Transmission Line Modeling	5-149
5.3.3.18.3 : Building and Sourcing Services.....	5-150
5.3.4 Asset management and inspections	5-151
5.3.4.1 Detailed inspections of Distributed Electric Lines and Equipment.....	5-156
5.3.4.2 Detailed Inspections of Transmission Electric Lines and Equipment.....	5-157
5.3.4.3 Improvement of Inspections.....	5-159
5.3.4.4 Infrared Inspections of Distribution Electric Lines and Equipment	5-160
5.3.4.5 Infrared Inspections of Transmission Electric Lines and Equipment.....	5-161
5.3.4.6 Intrusive Pole Inspections.....	5-162
5.3.4.7 LiDAR Inspections of Distribution Electric Lines and Equipment.....	5-163
5.3.4.8 LiDAR Inspections of Transmission Electric Lines and Equipment.....	5-164

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

5.3.4.9 Other Discretionary Inspection of Distribution Electric Lines and Equipment, Beyond Inspections Mandated By Rules and Regulations	5-165
5.3.4.10 Other Discretionary Inspection of Transmission Electric Lines and Equipment, Beyond Inspections Mandated by Rules and Regulations	5-166
5.3.4.11 Patrol Inspections of Distribution Electric Lines and Equipment.....	5-167
5.3.4.12 Patrol Inspections of Transmission Electric Lines and Equipment.....	5-168
5.3.4.13 Pole Loading Assessment Program to Determine Safety Factor.....	5-169
5.3.4.14 Quality Assurance/Quality Control of Inspections	5-170
5.3.4.15 Substation Inspections.....	5-172
5.3.5 Vegetation Management and Inspections	5-174
5.3.5.1 Additional Efforts to Manage Community and Environmental Impacts	5-180
5.3.5.2 Detailed Inspections of Vegetation Around Distribution Electric Lines and Equipment	5-182
5.3.5.3 Detailed Inspections of Vegetation Around Transmission Electric Lines and Equipment	5-184
5.3.5.4 Emergency Response Vegetation Management Due to Red Flag Warning or Other Urgent Conditions	5-186
5.3.5.5 Fuel Management and Reduction of “Slash” From Vegetation Management Activities	5-187
5.3.5.6 Improvement of Inspections.....	5-188

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

5.3.5.7 LiDAR Inspections of Vegetation Around Distribution	
Electric Lines and Equipment	5-188
5.3.5.8 LiDAR Inspections of Vegetation Around Transmission	
Electric Lines and Equipment	5-189
5.3.5.9 Other Discretionary Inspection of Vegetation Around Distribution	
Electric Lines and Equipment, Beyond Inspections Mandated by	
Rules and Regulations	5-190
5.3.5.10 Other Discretionary Inspection of Vegetation Around Transmission	
Electric Lines and Equipment, Beyond Inspections Mandated by	
Rules and Regulations	5-191
5.3.5.11 Patrol Inspections of Vegetation Around Distribution	
Electric Lines and Equipment	5-191
5.3.5.12 Patrol Inspections of Vegetation Around Transmission	
Electric Lines and Equipment	5-191
5.3.5.13 Quality Assurance/Quality Control of Inspections	5-191
5.3.5.14 Recruiting and Training of Vegetation	
Management Personnel	5-193
5.3.5.15 Remediation of At-Risk Species	5-195
5.3.5.16 Removal and Remediation of Trees With Strike Potential to	
Electric Lines and Equipment	5-197
5.3.5.17 Substation Inspections.....	5-199
5.3.5.18 Substation Vegetation Management.....	5-200
5.3.5.19 Vegetation Inventory System	5-200
5.3.5.20 Vegetation Management to Achieve Clearances Around	
Electric Lines and Equipment	5-200
5.3.6 Grid Operations and Protocols.....	5-201

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

5.3.6.1 Automatic Recloser Operations	5-202
5.3.6.2 Crew-Accompanying Ignition Prevention and Suppression Resources and Services.....	5-204
5.3.6.3 Personnel Work Procedures and Training in Conditions of Elevated Fire Risk	5-205
5.3.6.4 Protocols for PSPS Re-Energization	5-207
5.3.6.5 PSPS Events and Mitigation of PSPS Impacts	5-210
5.3.6.6 Stationed and On-Call Ignition Prevention and Suppression Resources and Services.....	5-212
5.3.7 Data Governance	5-212
5.3.7.1 Centralized Repository for Data.....	5-214
5.3.7.2 Collaborative Research on Utility Ignition and/or Wildfire	5-218
5.3.7.3 Documentation and Disclosure of Wildfire-Related Data and Algorithms	5-220
5.3.7.4 Tracking and Analysis of Near Miss Data	5-221
5.3.8 Resource Allocation Methodology	5-222
5.3.8.1 Allocation Methodology Development and Application	5-224
5.3.8.2 Risk Reduction Scenario Development and Analysis	5-225
5.3.8.3 Risk Spend Efficiency Analysis.....	5-227
5.3.9 Emergency Planning and Preparedness.....	5-229
5.3.9.1 Adequate and Trained Workforce for Service Restoration	5-239
5.3.9.2 Community Outreach, Public Awareness, and Communications Efforts	5-240
5.3.9.3 Customer Support in Emergencies	5-242
5.3.9.4 Disaster and Emergency Preparedness Plan	5-243
5.3.9.5 Preparedness and Planning for Service Restoration	5-245

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

5.3.9.6 Protocols in Place to Learn from Wildfire Events	5-246
5.3.9.7 Other / Not Listed [Only if an Initiative Cannot Feasibly be Classified Within Those Listed Above]	5-247
5.3.9.7.1 Resource Sharing to Support Inspection Work and Other Aspects of the Wildfire Management Plan	5-247
5.3.10 Stakeholder Cooperation and Community Engagement	5-248
5.3.10.1 Community Engagement	5-249
5.3.10.2 Cooperation and Best Practice Sharing With Agencies Outside CA	5-251
5.3.10.3 Cooperation with Suppression Agencies	5-252
5.3.10.4 Forest Service and Fuel Reduction Cooperation and Joint Roadmap	5-254
5.3.11 Definitions of Initiative Activities by Category	5-257
5.4 Methodology for Enterprise-Wide Safety Risk and Wildfire-Related Risk Assessment	5-268
5.5 Planning for Workforce and Other Limited Resources	5-271
5.6 Expected Outcomes of 3-Year Plan	5-273
5.6.1 Planned Utility Infrastructure Construction and Upgrades	5-273
5.6.1.1 Changes in Geographic Location of Facilities	5-274
5.6.1.2 Costs of System Hardening Exceeding \$0.5 Million Per Customer	5-276
5.6.1.3 Wildfire Mitigation Strategy Impact on Construction and Upgrades	5-277
5.6.2 Protocols on Public Safety Power Shutoff	5-283
5.6.2.1 Strategy to Minimize Public Safety Risk During High Wildfire Risk Conditions	5-286

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF CONTENTS

5.6.2.1.1 Reducing Scope, Duration, and Frequency of PSPS Events	5-286
5.6.2.1.2 Mitigating Impacts on De-Energized Customers	5-288
5.6.2.2 PSPS Decision-Making Protocols.....	5-293
5.6.2.3 Re-Energization Strategy.....	5-297
5.6.2.4 Customer, Agency, and External Communications.....	5-298
5.6.2.5 Protocols for Mitigating Public Safety Impacts of PSPS.....	5-306
6 Utility GIS Attachments.....	6-1
6.1 Recent Weather Patterns	6-1
6.2 Recent Drivers of Ignition Probability	6-1
6.3 Recent Use of PSPS.....	6-1
6.4 Current Baseline State of Service Territory and Utility Equipment	6-1
6.5 Location of Planned Utility Equipment Additions or Removal.....	6-1
6.6 Planned 2020 WMP Initiative Activity by End-2022.....	6-1
Appendices	
Glossary of Defined Terms	App1-1
Acronym List.....	App2-1
Confidentiality Declaration	App3-1
Attachments (available on website)	
1 All Tables Required by the WMP Guidelines	Atch1-1
2 List of Community Resource Centers Per Section 5.6.2.2	Atch2-1
3 List of Critical Facilities Per Section 5.6.2.4 (CONFIDENTIAL)	Atch3-1
4 PG&E's Utility Survey Responses.....	Atch4-1
5 Additional Detail on PG&E's Utility Survey Responses	Atch5-1
6 GIS Files.....	Atch6-1

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF TABLES

TABLE 1: RECENT PERFORMANCE ON PROGRESS METRICS, LAST 5 YEARS	2-5
TABLE PG&E-2-1: PG&E OH LINE MILES	2-7
TABLE PG&E-2-2: ANNUAL DAYS RFW CIRCUIT MILE	2-10
TABLE 2: RECENT PERFORMANCE ON OUTCOME METRICS, LAST 5 YEARS	2-11
TABLE PG&E-2-2: ANNUAL RFW DAYS – OH CIRCUIT MILES (T&D COMBINED)	2-18
TABLE 3: LIST AND DESCRIPTION OF ADDITIONAL METRICS, LAST 5 YEARS	2-21
TABLE PG&E-2-2: ANNUAL RFW DAYS – OH CIRCUIT MILES (T&D COMBINED)	2-23
TABLE PG&E-2-3: ANNUAL RFW DAY - OH DISTRIBUTION CIRCUIT MILES	2-24
TABLE 4: LIST AND DESCRIPTION OF PROGRAM TARGETS, LAST 5 YEARS	2-26
TABLE 5: ACCIDENTAL DEATHS DUE TO UTILITY WILDFIRE MITIGATION INITIATIVES, LAST 5 YEARS	2-31
TABLE 6: OSHA-REPORTABLE INJURIES DUE TO UTILITY WILDFIRE MITIGATION INITIATIVES, LAST 5 YEARS	2-32
TABLE 7: METHODOLOGY FOR POTENTIAL IMPACT OF IGNITIONS	2-34
TABLE 8: MAP FILE REQUIREMENTS FOR RECENT AND MODELLED CONDITIONS OF UTILITY SERVICE TERRITORY, LAST 5 YEARS	2-39
TABLE 9: MAP FILE REQUIREMENTS FOR BASELINE CONDITION OF UTILITY SERVICE TERRITORY PROJECTED FOR 2020	2-40
TABLE 10: WEATHER PATTERNS, LAST 5 YEARS	3-2
TABLE PG&E-3-1: NON-EXEMPT FUSE DEVICES IN HFTD TIERS 2 AND 3	3-6
TABLE 11-1: KEY RECENT DRIVERS OF IGNITION PROBABILITY, LAST 5 YEARS – DISTRIBUTION SYSTEM	3-7

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF TABLES
(CONTINUED)

TABLE 11-2: KEY RECENT DRIVERS OF IGNITION PROBABILITY, LAST 5 YEARS – TRANSMISSION SYSTEM	3-10
TABLE 12: RECENT USE OF PSPS, LAST 5 YEARS.....	3-14
TABLE 13: CURRENT BASELINE STATE OF SERVICE TERRITORY AND UTILITY EQUIPMENT	3-17
TABLE 14: SUMMARY DATA ON WEATHER STATION COUNT	3-21
TABLE 15: SUMMARY DATA ON FAULT INDICATOR COUNT	3-22
TABLE 16: LOCATION OF PLANNED UTILITY EQUIPMENT ADDITIONS OR REMOVAL BY END OF 3-YEAR PLAN TERM.....	3-24
TABLE 17: LOCATION OF PLANNED UTILITY INFRASTRUCTURE UPGRADES	3-27
TABLE 18-1: KEY DRIVERS OF IGNITION PROBABILITY – DISTRIBUTION.....	3-30
TABLE 18-2: KEY DRIVERS OF IGNITION PROBABILITY – TRANSMISSION...	3-32
TABLE PG&E 4-1:.....	4-4
TABLE 19: MACRO TRENDS IMPACTING IGNITION PROBABILITY AND/OR WILDFIRE CONSEQUENCE.....	4-15
TABLE 20: ANTICIPATED CHARACTERISTICS OF PSPS USE OVER NEXT 10 YEARS.....	4-29
TABLE PG&E 5-1: MAJOR INVESTMENTS AND IMPLEMENTATION OF WILDFIRE MITIGATION – INITIATIVES CATEGORY	5-6
TABLE 5.1.D.3: SELECT NEW OR EMERGING TECHNOLOGIES	5-13
TABLE PG&E 5-2: SELECTION OF GIS DATASETS APPLICABLE TO UNDERSTANDING WILDFIRE RISK AND CONDITIONS.....	5-31
TABLE PG&E 5-3: WILDFIRE SAFETY INSPECTION PROGRAM (WSIP) TAG PRIORITY CLASSIFICATION.....	5-41
TABLE PG&E 5-4: PG&E'S METHOD FOR COMPLYING WITH THE S-MAP SETTLEMENT AGREEMENT	5-268
TABLE 31-1: DISTRIBUTION.....	5-280
TABLE 31-2: TRANSMISSION.....	5-281

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF FIGURES

FIGURE PG&E 2-1: CPUC 2018 FIRE-THREAT MAP	2-2
FIGURE PG&E 2-2: FIRE IMPACT AREA (FIA) MAP	2-9
FIGURE PG&E 3-1: WUI AREAS WITHIN CALIFORNIA (2010)	3-16
FIGURE PG&E 4-1: PG&E WILDFIRE RISK "BOWTIE" ANALYSIS	4-7
FIGURE PG&E 4-2: FIRE RISK MODEL INTERACTION: OUTAGE PRODUCING WINDS AND FIRE POTENTIAL INDEX	4-11
FIGURE PG&E 4-3: 30-YEAR HISTORICAL ANNUAL AVERAGE OF "DIABLO WIND EVENTS" GEOGRAPHICALLY	4-12
FIGURE PG&E 5-1: AVERAGE ANNUAL NUMBER OF DIABLO WIND EVENTS	5-45
FIGURE PG&E 5-2: PROJECTED CHANGED IN ANNUAL AREA BURNED BY 2050 RELATIVE TO HISTORICAL BASELINE	5-46
FIGURE PG&E 5-3: PG&E'S DISTRIBUTION LINE WILDFIRE RISK RANKING WITH PROBABILITY OF IGNITION.....	5-49
FIGURE PG&E 5-4: SAMPLE PRODUCT MENU FOR THE POMMS MODEL	5-62
FIGURE PG&E 5-5: POMMS MODEL OUTPUT, WIND GUSTS/WIND SPEED BARBS.....	5-63
FIGURE PG&E 5-6: POMMS MODEL OUTPUT, 2M TEMPERATURE/WIND BARB	5-64
FIGURE PG&E 5-7: EXAMPLE OUTPUT FROM THE FIRE SPREAD MODEL APPLICATION – COLOR CODING REPRESENTS THE MAXIMUM FIRE SIZE SIMULATED FROM EACH OVERHEAD CIRCUIT	5-66
FIGURE PG&E 5-8: EXAMPLE OUTPUT FROM THE FIRE SPREAD MODEL APPLICATION	5-67
FIGURE PG&E 5-9: PG&E WEATHER STATION AND ASSOCIATED INSTALLATION DETAIL	5-69
FIGURE PG&E 5-10: INTERNAL WEB APPLICATION DEVELOP BY PG&E THAT SHOWS REAL-TIME WEATHER STATION DATA FROM MULTIPLE NETWORKS (PG&E, NWS, RAWS)	5-70

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF FIGURES
(CONTINUED)

FIGURE PG&E 5-11: THE PG&E WIND ALERT SYSTEM THAT DISPLAYS AND ALSO DISSEMINATES ALERTS WHEN WIND SPEEDS EXCEED THRESHOLDS – USERS CAN CUSTOMIZE ALERTS TO ONLY RECEIVE ALERTS FOR THE AREA(S) NEEDED	5-71
FIGURE PG&E 5-12: EXAMPLE CAMERA OUTPUT, WEB INTERFACE, AND CAMERA NETWORK DENSITY FROM WWW.ALERTWILDFIRE.ORG	5-73
FIGURE PG&E 5-13: EXAMPLE OUTPUT OF THE PG&E FIRE DETECTION AND ALERT SYSTEM (FDAS) – SNAPSHOT TAKEN ~3:45 PM 9/9/2019 AND ACTIVE FIRE SHOWN IS THE WALKER FIRE – VIIRS AND MODIS FIRE DETECTIONS ARE NOT SHOWN	5-75
FIGURE PG&E 5-14: EXAMPLE FIRE DETECTION ALERT EMAIL DISTRIBUTED AUTOMATICALLY BY THE PG&E FIRE DETECTION AND ALERT SYSTEM – THIS INCIDENT WAS THE MARSH FIRE THAT WAS REPORTED IN CONTRA COSTA COUNTY ON AUGUST 3, 2019	5-76
FIGURE PG&E 5-15: EXAMPLE INTEGRATION OF PG&E WILDFIRE CAMERAS AND THE PG&E F DAS –THIS EXAMPLE SHOWS A SMOKE PLUME VISIBLE FROM A FIRE DETECTED FROM FDAS – THIS EXAMPLE IS FROM THE FIRE THAT OCCURRED IN THE NUSTAR ENERGY FACILITY IN CROCKLETT, CA	5-77
FIGURE PG&E 5-16: EXAMPLE OUTPUT FROM THE PG&E PRESSURE GRADIENT TRACKING TOOL THAT SHOWS OBSERVATIONS (BLACK DOTS) VERSUS PRESSURE GRADIENT FORECASTS FROM SEVERAL DETERMINISTIC FORECAST MODELS	5-80
FIGURE PG&E 5-17: EXAMPLE OUTPUT FROM THE PG&E ECMWF ENSEMBLE PREDICITON SYSTEM (EPS) GRADIENT TOOL THAT SHOWS MODEL RESULTS FROM 50 EPS MEMBERS (GRAY LINES) THE TOP AND BOTTOM 10% (LIGHT BLUE SHADING), THE EPS MEAN (BLACK LINE) AND THE DETERMINISTIC ECMWF MODEL (RED LINE) ...	5-81

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILD FIRE MITIGATION PLAN

TABLE OF FIGURES
(CONTINUED)

FIGURE PG&E 5-18: EXAMPLE OUTPUT FROM THE PG&E ECMWF ENSEMBLE PREDICTION SYSTEM (EPS) PRECIPITATION TOOL THAT SHOWS MODEL RESULTS FROM 50 EPS MEMBERS (GRAY LINES) THE EPS MEAN (GREEN LINE), THE EPS MEDIAN (BLACK LINE) AND THE DETERMINISTIC ECMWF MODEL (BLUE LINE)	5-82
FIGURE PG&E 5-19: EXAMPLE OUTPUT FROM THE PG&E LIGHTNING DETECTION NETWORK (PLDN) SHOWING HISTORICAL LIGHTNING FROM MARCH 27, 2019.....	5-84
FIGURE PG&E 5-20: EXAMPLE OF A PSPS FORECAST ISSUED ON 10/6 FOR AN UPCOMING PERIOD OF FIRE RISK ON 10/9- 10/11.....	5-86
FIGURE PG&E 5-21: EXAMPLE OUTPUT FROM THE PG&E UTILITY FIRE POTENTIAL INDEX WEB APPLICATION.....	5-100
FIGURE PG&E 5-22: EXAMPLE OUTPUT FROM THE PG&E WILDFIRE DANGER CONSOLE	5-101
FIGURE PG&E 5-23: EXAMPLE OUTPUT FROM THE PG&E WILDFIRE DANGER CONSOLE – FIRE FAMILY PLUS AUTOMATED UPDATES	5-102
FIGURE PG&E 5-24: EXAMPLE OUTPUT AND HOURLY VISUALIZATION OF THE PG&E OPW MODEL BASED ON POMMS.....	5-108
FIGURE PG&E 5-25: EXAMPLE OUTPUT FROM THE DYNAMIC PATTERN AND ANALOG MATCHER (DPAM) TOOL DEVELOPED BY PG&E USING GRS AND NARR ARCHIVE DATA	5-109
FIGURE PG&E 5-26: SYSTEM HARDENING REMAINING RELATIVE RISK SCORE	5-274
FIGURE PG&E 5-27: PSPS DECISION MAKING PROCESS WITH OIC DECISION POINTS (SUBJECT TO CHANGE AS REQUIRED BY PROGRAM EVOLUTION).....	5-295

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION PLAN
EXECUTIVE SUMMARY

**PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION PLAN
EXECUTIVE SUMMARY**

A. Introduction

Over the past few years, California has experienced an unprecedented number of catastrophic wildfires due to climate change. Many of these fires have occurred in Pacific Gas and Electric Company's (PG&E or the Company) service territory in Northern California. PG&E recognizes the urgent need to reduce the frequency, scope and impact of wildfires and is taking extensive measures to address this challenge and protect the safety of the customers and communities we serve.

PG&E conducted massive Vegetation Management (VM) and asset inspection efforts in 2019. At the same time, we worked with regulators, communities, other utilities and industry experts to get a better understanding of the wildfire problem and ways to address and limit wildfire risk. Based on our work and experience in 2019, in 2020 PG&E will be implementing continued VM activities, enhanced inspection practices, more strategic system hardening, increased situational awareness tools, and additional system automation devices. In addition to further reducing wildfire risk we anticipate these efforts will enable the Company to implement smarter, smaller, and shorter Public Safety Power Shutoffs (PSPS) during future fire seasons.

This document describes the measures that PG&E is taking to reduce the risk of catastrophic wildfires in Northern California. These measures have ramped up in the last few years because Northern California's wildfire problem has grown significantly during that time. These programs are evolving as our understanding of the wildfire threat improves, and as we learn more from the customers, communities and governments we serve about how to improve the effectiveness and impact of these efforts. The table on the next page summarizes the major 2020 wildfire mitigation activities described in Section 5 of PG&E's 2020 Wildfire Mitigation Plan (WMP).

B. PG&E's System and Wildfire Threat

Over half of PG&E's service territory lies in the High Fire Threat District (HFTD) as identified by the California Public Utilities Commission (CPUC or Commission) in 2018. Approximately 5,500 line-miles of electric transmission and 25,500 line-miles of distribution assets lie within these HFTDs. Many of these are long lines that serve low-density, non-urban customers and communities located within the "wildland-urban

interface," who face an increased fire risk. This wildfire threat has increased significantly over the past ten years. The U.S. Forest Service estimates that 147 million trees died in California from drought and invasive beetles from 2010-2018. This contributed to the CPUC significantly increasing the size of the HFTDs within PG&E's service territory, effective January 2018.



TABLE 1
SUMMARY OF 2019 AND 2020 WILDFIRE MITIGATION ACTIVITIES

	PROGRAM	2019 PROGRESS*	2020 TARGETS*	NOTES	REFERENCE
REDUCE WILDFIRE IGNITION POTENTIAL	1.A Enhanced VM — VM and Tree Clearing Reduce Fire Risk by Reducing Potential Vegetation Contacts With Utility Equipment				
	Enhanced VM (EVM)	2,498 line-miles	1,800 line-miles	EVM activities are in addition to PG&E's routine VM practices.	5.3.5
	Catastrophic Event Memorandum Account (CEMA) (Dead Tree Removal)	48,000 trees	Removals per inspection results	2020 activities will include some trees identified in 2019	5.3.5.9
	1.B Asset Inspection and Repair/Replacements — Identify and Fix Actual and Potential Equipment Problems That Could Contribute to a Failure or Wildfire Ignition				
	Enhanced Inspections	Transmission – aerial and visual for 49,715 structures	Transmission – aerial and visual for ~22,000 structures	Transmission 2019 data reflect some inspections performed in late 2019 as well.	5.3.4.2
		Distribution – 694,250 poles	Distribution – ~344,000 poles	All structures in HFTD inspected in 2019 and late 2018; for 2020 all HFTD Tier 3 and one third of Tier 2 assets will be inspected.	5.3.4.1
		Substations – 222	Substations – ~105		5.3.4.15
	Repairs and Replacements	Transmission – repaired 5,215 A&B tags	Continue risk-prioritized repairs identified in 2019 and perform new corrective actions identified during 2020 inspections.	Repaired all A tags and 94 percent of B tags identified through 2019 inspections.	5.3.4.2
		Distribution – repaired 4,881 A&B tags			5.3.4.1
		Substations – repaired 745 A&B tags			5.3.4.15
	1.C System Hardening — Replace or Eliminate Overhead Distribution Lines in High-Risk Areas With Stronger, More Resilient Equipment				
	Miles Hardened	171 line-miles	241 line-miles	Hardening includes replacing bare overhead conductor by (1) eliminating the line entirely, (2) undergrounding or (3) replacing with covered conductor and stronger poles.	5.3.3
	1.D System Automation — Enable Remote Control and Automated Operation of Field Equipment to More Precisely Deenergize Sections of the Grid When Fire Risk Is High				
	Reclosers	Supervisory Control and Data Acquisition (SCADA)-enabled all remaining (287) manual reclosers	SCADA expansion as needed	SCADA-enabled recloser allows remote control to prevent a line from reenergizing after a fault.	5.3.3.9
REDUCE FIRE	Automated Sectionalization	298 devices	592 devices	Sectionalization devices enable separating the distribution grid into smaller sections for greater operational flexibility	5.3.3.8
	1.E Public Safety Power Shutoffs — Shutting Off Power in High-Risk Fire Areas Under High-Risk Weather Conditions Prevents Utility Equipment From Igniting a Potentially Catastrophic Fire				
	PSPS Events	9 PSPS outages lasting from ~14 to 55 hours (on average for all affected customers)	Working to make each 2020 PSPS event affect one-third fewer customers than it would have in 2019 and to shorten restoration time after high-risk weather clears to ~50 percent shorter than the 2019 PSPS target.	Particularly working to reduce PSPS impacts on communities forecast to be most frequently affected by PSPS events.	4.1
	2.A Situational Awareness — More Real-Time Monitoring of High-Risk Fire Areas Enables Earlier Warning and Detection of Wildfires, More Effective Proactive Grid Operation, and Faster Response by First Responders				
	Weather Stations	426 installed (total 626 to date)	Install 400 in 2020; goal of 1,300 total by 2021	These tools enable better real-time monitoring of high-risk fire areas and conditions; all data feeds are shared publicly at pge.com/weather .	5.3.2.1
REDUCE FIRE	High-Def Cameras	133 installed (total 142 to date)	Install 200 in 2020; goal of 600 total by 2022		5.3.2.1
	2.B Wildfire Safety Operations Center and Meteorology — Leverage Better Situational Awareness and Analytical Capability to Identify and Respond to Fire Threats More Effectively				
	Wildfire Risk Identification	Enhanced meteorology and Wildfire Safety Operations Center (WSOC) capabilities and tools including Satellite Fire Detection technology and fire spread modeling to better understand real-time (and modeled) wildfire risk.	Continue integrating all weather and wildfire forecasting, modeling and situational awareness tools		5.3.2

TABLE 1
SUMMARY OF 2019 AND 2020 WILDFIRE MITIGATION ACTIVITIES
(CONTINUED)

	PROGRAM	2019 PROGRESS*	2020 TARGETS*	NOTES	REFERENCE
REDUCE	3.A Reduce Number of PSPS-Affected Customers — Smaller Distribution Sections, More Precise Transmission Line Switching and Operating Temporary Microgrids Make it Possible to Reduce the Size of PSPS Outages				
	Distribution Sectionalization	See 1.D above	See 1.D above	Distribution sectionalization makes it possible to focus PSPS outages on smaller sections of the grid, and transmission switching enables more targeted transmission outages to lessen downstream customer impacts.	5.3.3.8
	Transmission Line Switching	None completed for PSPS mitigation purposes	23 switches		5.3.3.8
	Distributed Generation and Microgrids	Completed 1 temporary microgrid pilot and operated 3 additional temporary microgrids during PSPS events	Operate additional microgrids during PSPS events in 2020		5.3.3.8
	3.B Reduce PSPS duration — Shorter Outages, Through Increased Operational Tools and Improved Processes, Will Reduce Burden of PSPS Events on Customers and Communities				
	Faster Power Restoration	PSPS Restoration target of 24 daylight hours from weather "all clear" to power restored, generally achieved	New PSPS Restoration target aims for 50 percent improvement: restore power for 98 percent of affected customers within 12 daylight hours from weather "all clear"	Faster power restoration should reduce the degree of customer and community disruption from an outage.	5.6.2.3
	3.C Reduce Frequency of PSPS — Tighter Geographic Understanding of Weather and Fire Risk And Analysis of Transmission Lines Allows More Accurate Design of PSPS Need and Scope				
	Meteorology	Weather forecasted at 3 km X 3 km resolution. Updated weather impact models, datasets & improved meteorology computing power.	Integrating additional tools and datasets to increase weather forecast granularity to 2 km x 2 km (>2x better than 2019 resolution)	Better meteorology tools and geographic precision improves identification of high-risk fire conditions and thus better tailoring of operational actions to respond to high-risk threats and events.	5.3.2.1
	Transmission Line Assessment	Limited assessments in 2019	PG&E is analyzing all 500+ transmission lines that run through HFTDs to identify possible ways to avoid taking a line out of service under high fire risk conditions.		5.3.3.8
	3.D Community and Customer Support — Lessen the Burden of PSPS Outages by Increasing Customer and Community Coordination, Information, Preparation and Services Before and During Outages				
	Community Resource Centers (CRC)	Established 70+ temporary CRCs during late October / early November 2019 PSPS event	Partnering with counties to improve targeting of CRCs, including using existing buildings as well as temp facilities in coordination with distributed generation		5.6.2.1
	Communication and Outreach	Community outreach program included hosting 23 open houses plus webinars and other events throughout the service territory to educate customers about wildfire risks, wildfire preparations, and PG&E's Wildfire Safety Programs and PSPS	Approximately doubling the number of in-person open houses across potentially affected areas to educate and inform customers, alongside other additional outreach measures. Improve social media usage for customer information and feedback.		5.3.9.2
	Website and Call Center	Website upgrades since October 2019 include improved scalability of PGE.com using cloud-based systems; Call Center Operations refined to support peak call volumes during PSPS events	Continuing to test and monitor website capacity and call center operations, including flexible human resource deployment, to support peak PSPS-event web traffic and call volumes		5.6.2.4
* All data are for activities and assets within CPUC-designated HFTDs unless otherwise indicated; 2020 activities will include some items identified in 2019; targets as of February 7, 2020.					

1. Reduce Wildfire Ignition Potential

Reducing the risk of catastrophic fires begins with understanding the causes of utility-related fire ignitions in PG&E's service territory. Historically, 49 percent of ignitions in PG&E's HFTD regions have been caused by vegetation contact with electrical equipment and another 28 percent were caused by utility equipment failures; the remaining ignitions were caused by third-party actions, animals, and other causes. Although PG&E was following regulatory requirements and standard industry practices for VM (tree-trimming) and equipment inspections and maintenance, the increased number of dead trees, drought, hotter temperatures and higher winds due to climate change have radically increased the risk of a significant wildfire in the event of an ignition.

PG&E is going beyond existing regulatory requirements to address the new normal. In 2018 PG&E developed an aggressive program to reduce wildfire ignitions, with five primary elements that directly address the causes of fire ignition and spread.

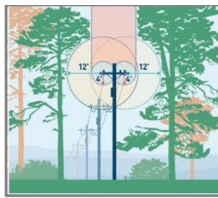
a. Enhanced VM

Vegetation located in close proximity to electrical equipment can cause a fire by contacting that equipment, either catching fire or dropping a spark that could cause other vegetation to catch fire. Vegetation trimming and dead tree removal also reduce the availability of fuel that could start or spread a fire, whatever the cause. PG&E's routine VM program inspects approximately 100,000 miles of overhead electric facilities at least annually to identify and clear vegetation that might grow or fall into utility equipment to reduce the risk of contact and ignition. The vegetation inspection process entails ground patrols and the use of Light Detection and Ranging and advanced analysis techniques to identify ~~trees that pose a strike risk to~~ that are too close to utility facilities.

In addition to the routine VM practices, in 2019 PG&E's EVM Program inspected and further trimmed or removed vegetation along 2,498 line-miles (~10 percent) of distribution lines within HFTDs. Beyond the EVM and routine vegetation clearance work, PG&E also removed approximately 48,000 dead trees close to facilities through the CEMA Program. These measures reduce the likelihood of future vegetation-into-line fire ignitions and the amount of fuel available to spread a fire.

Deleted: dead and risky trees

FIGURE 2
PG&E'S EVM PROGRAM



- Enhanced Veg. Mgmt: High Risk Trees + Overhang Removal**
1. Maintain 12' recommended radial clearance
 2. Remove high risk trees within fall zone
 3. Remove overhangs out 4 feet from power lines
 4. Reduce dry fuel on a targeted basis

PG&E plans to conduct EVM on approximately 1,800 miles of lines in 2020 and beyond based on insights gained from the 2019 effort. We are assessing the impacts of the 2019 routine full system plus EVM efforts to be sure that we use our resources most effectively in the years ahead. For instance, we plan to shift some EVM work from distribution to lower voltage transmission lines to expand Rights-of-Way (ROW) and remove incompatible species; this work will reduce wildfire risk and reduce the footprint of future PPS events by allowing some transmission lines to remain energized.

b. Asset Inspection and Repair

Over late 2018 and 2019, PG&E inspected all equipment within the HFTDs in our service territory to identify any structures or equipment that were damaged, degraded or could fail and potentially cause a fire. While most utility equipment failures can be visually identified, PG&E has deployed a suite of techniques for enhanced inspection across transmission, distribution and substation equipment. These techniques include:

- Routine patrols by ground (truck and walking) or helicopter;
- Use of enhanced visual, infrared and ultrasonic inspection methods; and
- Structure climbing, aerial image capture, wood pole testing, ground and below-grade foundation assessment.

PG&E uses inspection results to prioritize and manage equipment repair needs. The most severe equipment problems are immediately repaired or made safe (potentially by taking the affected line out of service). Less severe problems are addressed within a risk-informed timeframe, based on CPUC requirements.

PG&E's 2019 Wildfire Safety Inspection Program covered all of the nearly 750,000 poles and structures in HFTDs and identified needed maintenance and replacement. Building on this foundation, PG&E is incorporating the enhanced inspection processes and tools into our Routine Inspection and Maintenance Program and will use risk-informed maintenance cycles in the years ahead—for instance, PG&E will initially conduct annual inspections of all facilities in HFTD Tier 3 areas and use 3-year inspection cycles for Tier 2 facilities. Future year inspection cycles may be adjusted to align with our understanding of the risks associated with changing weather patterns, repairs, replacements, and information gathered via inspections.

c. System Hardening

System hardening entails replacing or eliminating distribution lines in HFTD areas with equipment that is less likely to start a fire and more likely to survive one. Hardening methods include replacing bare overhead conductor with covered conductor and installing stronger poles or undergrounding a line. Some lines or spans could be eliminated entirely if customers, the community or a substation can be supplied through some other means, including remote grids or self-generation. Each system hardening project requires extensive field assessment and engineering analysis to determine the best method to reduce fire threat and consequence for that line. PG&E is starting this work in the areas that have been determined as the highest fire risk facilities.

In 2019, PG&E completed hardening for 171 miles of distribution lines. The 2020 system hardening plan targets hardening 241 line-miles and completing a total of 7,100 line-miles over 12-14 years.

d. System Automation

System automation is an important tool to prevent and mitigate fires associated with utility equipment. PG&E is using two principal automation tools on our system in HFTDs. PG&E has installed SCADA-enabled reclosers in place of manual devices, to allow system operators to remotely prevent a line from automatically reenergizing ("reclosing") after a fault. This assures that if any potential fire or other risk event causes a line to drop out of service, that line will remain out of service and not

contribute to a fire until PG&E personnel can verify that it is safe to put the line back in operation. In 2019, PG&E completed SCADA-enabling all line reclosers serving HFTD areas.

Automated sectionalization devices are used to separate the distribution grid into smaller sections for greater operational flexibility. These devices can be used to isolate parts of the grid, to respond to outages or emergency situations more quickly, or to create a zone for microgrid operations. PG&E will use sectionalization to create smaller zones for PSPS outages, and to take smaller sections out of service as needed for asset repairs or replacements. The Company installed 298 automated sectionalization devices in 2019 and plans to install another 592 devices in 2020.

Reclosers and automated sectionalization devices reduce wildfire risk by allowing PG&E operators to keep lines out of service to prevent ignitions under hazardous conditions. These devices enable deenergization and reenergization of smaller, more precise sections of the grid with higher speed, enabled by remote operation and automation.

e. Public Safety Power Shutoffs

In 2018, the CPUC confirmed the need for all California utilities to use PSPS as a way to prevent catastrophic wildfires. Significant wildfires are most likely to occur under the high-risk conditions of high winds, low humidity, and where there is a high level of dry fuel—as in the late summer or fall in the heavily forested mountain areas of Northern California, where many of PG&E's distribution and transmission assets (red lines in map) and power plants are located. Under extremely high-risk conditions, it is necessary to deenergize some transmission or distribution lines to reduce the risk that vegetation or other flammable items that could start a wildfire could contact live wires.

Extreme hazard weather conditions were particularly severe during the 2019 fire season, forcing PG&E to conduct nine PSPS events. The largest PSPS event occurred on October 26 through November 1, affecting approximately 968,000 customers in 38 counties for an average of about 55 hours and some communities for almost a week. During that period, peak wind gusts in the fire risk areas reached speeds as high as 102 miles per hour, which is strong enough to blow tree limbs into power lines from a considerable distance.

Executive Summary-9

about how to conduct these more effectively, and how to better help our customers prepare for and manage through PSPS events. We also worked to determine how to make future PSPS events smaller, shorter and less frequent. These lessons are discussed in Section 3 below.

PG&E's process for deciding whether to initiate a PSPS involves continuous monitoring to determine when and where extreme weather patterns and high-risk fire conditions exist. Under those circumstances, a PG&E officer, following well-documented policies, processes, and procedures, makes the decision on whether it will be necessary to shut down distribution lines in the identified high-risk fire areas. PG&E then begins governmental and customer notifications based on the identified distribution lines. PG&E also assesses the transmission circuits within the high-risk footprint and identifies the downstream areas and customers affected by those lines. We identify specific transmission lines that must be shut down based on updated wildfire risk and public safety risk. Company engineers perform electric power flow analyses to determine shut-down impacts and safe power rerouting options and coordinate those with the California Independent System Operator (i.e., CAISO, the state's grid operator). If additional areas must be deenergized due to transmission line shut-offs, PG&E updates governmental and customer notifications as soon as possible.

Once PG&E meteorologists issue the "weather all-clear" for a PSPS event, PG&E conducts safety assessments of our lines and equipment. The Company may use internal personnel, contractors, and mutual aid (personnel from other utilities) for ground patrols, as many as 65 helicopters for real-time aerial assessment, and fixed-wing aircraft with cameras and infrared equipment that may be able to inspect assets at night. PG&E repairs or resolves identified damage locations and issues such as vegetation on the lines and then reenergizes lines on a rolling basis to restore power to affected customers as quickly as is safe to do so.

PG&E recognizes the burden that PSPS places upon affected customers and communities and is committed to minimizing the number of PSPS events and their scope (number of customers affected) and duration, while working to keep our customers and communities safe during times of severe weather and high wildfire risk. The Company is adopting a variety of system tools and analytical methods, described below, to make future PSPS events smarter, smaller, and shorter.

2. Reduce Fire Spread

PG&E is continuing to invest in tools, equipment, resources and a skilled workforce to improve our understanding of upcoming and real-time weather and fire conditions, so we can act proactively to reduce fire ignitions and respond quickly to slow the spread of a fire once it starts.

a. Situational Awareness

PG&E is installing a variety of weather and fire monitoring devices across HFTD areas. These monitoring devices allow early warning of high fire risk conditions and real-time identification of emerging wildfires, which in turn enable faster action by first responders and more proactive grid operation to avert fire ignition and spread.

PG&E's situational awareness tools in the HFTDs include:

- Weather stations – PG&E installed 426 in 2019, for a total of 626 to date; another 400 will be installed in 2020;
- High-definition cameras – PG&E installed 133 in 2019, for a total of 142 to date; another 200 will be installed in 2020;
- Enhanced wire-down detection tools;
- Satellite monitoring of PG&E service territory; and
- Access to multiple external real-time weather service feeds.

All of these sources are used to track real-time fire conditions and create highly localized weather and fire risk forecasts. PG&E uses this information to flag high-risk locations and system conditions, share it with government and first responders, and activate PG&E field crews and operational measures accordingly to prevent outages and respond to wires down or actual fires.

b. Wildfire Safety Operations Center and Meteorology

PG&E has established a highly qualified, 24/7 meteorology operation that supports a WSOC, as well as day-to-day gas and electric system operations more broadly. These two integrated organizations have the field tools and analytical capabilities to forecast wildfire threats, identify actual fires, and support rapid fire response and grid operational responses.

PG&E's WSOC plays a key role in addressing the challenges of climate-driven extreme weather events and customer and community safety. The WSOC serves as a coordination, facilitation and communications hub for wildfire activities, including using weather data to monitor fire threats. In the event of a potential fire threat or actual fire,

it coordinates and mobilizes response efforts with appropriate PG&E field personnel, first responders, media, local government, and other safety officials. The WSOC operates on a 24-hour basis and is staffed with experienced personnel knowledgeable in electric operations, safety, engineering, meteorology, fire science and other areas. The WSOC staff includes field teams of Public Safety Specialists who train first responders and local agencies on how to safely respond to emergencies associated with electric and gas facilities. WSOC specialists partner with local entities for emergency planning and coordination and fire response.

PG&E's WSOC developed and deployed an industry-leading satellite fire detection system in 2019 that uses remote sensing data from five geostationary and polar orbiting satellites to detect fires. The Company has also developed a suite of fire spread modeling tools to understand potential wildfire risks and paths.

PG&E's meteorology department integrates weather data from numerous internal and external sources, including hundreds of PG&E's own weather stations located in HFTDs. Several times each day, PG&E meteorologists use these data streams to forecast wind and weather patterns and calculate fire risk levels across the service territory. These forecasts support PG&E operations and guide the need for wildfire preparation and mitigation activities, including possible PSPS.

In late 2018 and 2019, PG&E's meteorology team compiled one of the largest known high-resolution climatological datasets in the utility industry: a 30-year, hourly, 3 kilometer (km) spatial resolution dataset consisting of weather, dead and live fuel moistures and fire weather assessments, to improve identification of high-risk weather patterns. In 2019, PG&E's weather condition forecasting and fire risk analysis primarily used 3 km by 3 km resolution to forecast conditions within each 9 square km section of PG&E's entire HFTD area. In 2020, PG&E will be performing these forecasts at an even tighter resolution, in 2 km by 2 km sections. This improved geographical precision will allow better determination of which specific areas and lines are at high fire risk, and which lines at less risk can be excluded from potential PSPS consideration. This precision will also enable faster identification of when high fire risk has abated and assessment and reenergization can begin. PG&E will work in 2020 to further consolidate and integrate all of our situational awareness tools, data and analytical capabilities for deeper insights and actionable analyses.

3. Reduce impact of PSPS

PG&E is working to make PSPS de-energization events smaller, shorter and less burdensome on affected communities. In 2019, PG&E conducted nine PSPS events, most during October and November, causing outages that affected hundreds of thousands of customers. While the PSPS events were successful in that utility equipment caused fewer overall ignitions within HFTDs and no fatal wildfires occurred in 2019, those events caused severe disruptions for the communities and customers we serve.

Based on what we learned from the 2019 PSPS events, PG&E is working to make any future PSPS events smaller in scope, shorter in duration and smarter in performance while working to keep customers and communities safe during times of severe weather and high wildfire risk. By taking the actions described below, PG&E aims to have any 2020 PSPS events affect approximately one-third fewer customers than a comparable event would have in 2019 (based on an analysis of the projected impacts of these new programs under conditions of the large October 2019 PSPS events). We will focus particularly on how to alleviate the PSPS burden on the communities we serve in highest fire risk areas that are expected to be most frequently affected by PSPS events.

a. Reduce the number of PSPS-affected customers

One major factor affecting the scope of a PSPS event is the number of transmission lines included in the footprint of the event, as transmission lines have significant impacts on downstream communities that might otherwise not be affected by the extreme weather or are even outside a high fire risk area. PG&E will use several methods to further reduce the number of transmission lines that must be included in future PSPS events. The first step being taken is to analyze every one of the 552 transmission lines in HFTDs before the start of fire season to determine whether the various line inspections, repairs, VM and other measures taken have reduced fire risk for that line enough that it could be essentially removed from consideration for PSPS (or whether additional immediate action could do so). Second, on high risk fire days, more granular meteorological fire risk forecasting at 4 sq. km resolution may reveal that some transmission and distribution lines are not at high risk, so those lines would not need to be deenergized. Every line that can be safely excluded from a PSPS event reduces the number of customers subject to a PSPS outage.

PG&E's investment in additional transmission switching and distribution sectionalization will enable the Company to more precisely control and limit the size and sections that must be taken out of service in a PSPS event. By making those PSPS areas smaller, we can reduce the number of customers affected by an outage event.

PG&E is also using distributed generation, in combination with switching and sectionalization, to isolate particular communities and critical facilities and serve them when the rest of the local area is shut down by a PSPS. In 2019, PG&E completed a temporary microgrid pilot for PSPS mitigation in Angwin, California, and operated temporary microgrids at three substations during 2019 PSPS events. We intend to establish additional PSPS-mitigating microgrids and distributed generation resources in 2020.

b. Reduce PSPS Duration

With improved meteorology data on wildfire threat conditions, PG&E's ability to identify the start and end of high-risk weather will continue to improve. More sophisticated weather and fire risk understanding will inform PG&E's operational measures to respond to high-risk threats and events—and to confirm area-specific "weather all-clear" status more quickly to speed service restoration and shorten the duration of PSPS events.

Based on operational lessons learned from the 2019 PSPS season, PG&E is adjusting some practices and increasing the resources we will deploy to support PSPS restoration in 2020. PG&E is establishing contracts to have as many as 65 helicopters available for real-time aerial assessment (up from ~35 in 2019) and fixed-wing aircraft equipped with cameras and infrared equipment that may allow us to inspect assets at night. In 2019, PG&E's target was to restore service after a PSPS within 24 hours after the "weather all-clear." Leveraging these additional resources and other process improvements, for 2020 PG&E is aiming for a 50 percent improvement, restoring power for 98 percent of affected customers within 12 daylight hours from the "weather all-clear."

c. Reduce the frequency of PSPS

As noted above, more accurate weather and fire risk forecasting on a 2 km by 2 km resolution will improve threat identification and may enable PG&E to avoid calling PSPS in areas that are not at severe fire risk. PG&E's weather and fire forecasting improvements, particularly with respect to identifying high wind speeds and sustained

winds, may also help avoid over-estimating actual fire hazard levels, and thus avoid calling for a PSPS when weather and fire risk conditions may not require it. Better fire-spread modelling capabilities will also let PG&E determine when a potential or actual fire could have less severe consequences, and therefore may not merit PSPS action.

Advanced analyses of all of the HFTD transmission lines will enable PG&E staff to identify possible ways to avoid taking a line out of service under high fire risk circumstances. This will be particularly beneficial for customers who are served downstream from those lines.

d. Community and customer coordination and support

Given the high risk and consequences of catastrophic wildfires for California communities, and the high burdens created by PSPS events, communication and education about wildfire risks, preparations and possible PSPS events are essential. PG&E is building partnerships with all of our stakeholder groups, coordinating with affected governments and communities, improving customer communications, and listening carefully to all of these stakeholders to improve our customer and community support.

PG&E's activities have included extensive county and tribal engagement to improve coordination, including meetings, community open houses, listening sessions and joint identification of critical facilities. Key staff have been designated as community and governmental liaisons to coordinate and provide real-time information leading up to and during a PSPS event. Our teams coordinate year-round with fire and other first responder agencies on overall safety efforts, with an increasing focus on wildfire and PSPS preparation. We are working to serve Access and Functional Needs (AFN) customers more effectively, including identifying those customers for additional notification in the event of a PSPS event and establishing an AFN council to advise on and inform our practices.

PG&E has and is actively communicating and engaging customers and communities to learn how we can improve PSPS planning and community support. In 2019, PG&E conducted 23 open houses, 6 webinars, 17 PSPS planning workshops, and over 1,000 stakeholder meetings. The Company sent out 18.8 million PSPS-related direct mail pieces, ran 36,000 radio ads and used extensive social media outreach and web-based information such as outage maps and the locations of emergency support services. PG&E values the many requests and suggestions from

our customers and our communities, the CPUC, the Governor's office, state agencies and other stakeholders. We implemented many suggestions and improvements in real time during successive PSPS events in 2019 and are working to implement more for potential future PSPS events. Our 2020 outreach will expand upon 2019 efforts, including approximately doubling the number of community open houses, and continue to address emergency readiness and reach vulnerable populations using diverse outreach opportunities and communications channels.

PG&E is committed to reducing the number of customers affected by and duration of future PSPS events. But given the high fire risk in our service territory, it is not possible to eliminate all PSPS events in the near future. Acknowledging this reality, PG&E has worked to implement CRCs in communities affected by PSPS events, to give customers a place to go for essential services when power is out. In coordination with local communities and governments, PG&E set up 77 temporary CRCs by the last PSPS of 2019 and is working now to see whether some permanent facilities (such as schools or community centers) are appropriate and feasible to be used as CRCs in 2020.

4. Program Evolution for Continuous Improvement

PG&E's Community Wildfire Safety Program (CWSP) is evolving rapidly as we gain experience on how various measures and technologies work to reduce the threat and actuality of catastrophic fires. Actions such as VM, equipment repairs and line hardening may materially reduce the risk, number and extent of wildfires—but at the same time, climate change-driven factors such as drought, high temperatures and bark beetles may increase that risk and counteract our efforts over time. PG&E will study and analyze the impact and cost-effectiveness of the measures we are taking. We will work with our customers, communities and partners to learn how to serve their needs better and reduce wildfire and wildfire mitigation consequences in the future.

We are continuing to identify and incorporate lessons learned from 2019 into PG&E's wildfire mitigation efforts, this 2020 WMP and the associated program targets. Some key examples include:

- **Enhanced VM (1.A):** Based on analysis of the 2019 routine full system plus EVM efforts, PG&E is re-balancing VM activities to use VM labor resources more effectively in the years ahead. In particular, we will be shifting resources to expand ROWs on lower voltage transmission lines, for the double benefit of reducing wildfire risk and possibly reducing the footprint of future PSPS events.

- Enhanced Inspections (1.B): PG&E performed enhanced inspections of all poles and structures within HFTDs in 2019. With that assessment of all HFTD structures as the foundation, PG&E is adopting a risk-informed inspection process going forward. We have incorporated 2019's enhanced inspection processes and tools into our Routine Asset Inspection Program. Starting in 2020, we will inspect facilities in HFTD Tier 3 annually and inspect Tier 2 facilities on a 3-year cycle. This will deploy inspection resources more cost-effectively and facilitate a thorough understanding of asset conditions in the high fire threat areas.
- System Hardening (1.C): Building on operational insights and system hardening work from the second half of 2019, PG&E is increasing system hardening line-miles by over 40 percent starting in 2020.
- PSPS Scope Mitigations (3.A): Based on analysis of the 2019 PSPS events, PG&E will be using the automation measures and transmission impact analyses discussed above to reduce the size of PSPS events for the 2020 wildfire season. We will also use microgrids and distributed generation to support some communities in PSPS zones. These efforts are expected to reduce 2020 PSPS customer impacts by one third relative to comparable fire-risk events in 2019.
- PSPS Duration Reduction (3.B): Building on the operational practices and insights from 2019, PG&E will leverage additional resources and processes for asset inspection and fire condition monitoring to speed post-event restoration.

PG&E anticipates that the programs and approaches described in this plan will further change and evolve over time to reflect new insights, risks, and opportunities. This may create inconsistencies with PG&E's CWSP proposals in the General Rate Case (GRC) or other regulatory proceedings. In December 2019, PG&E and other parties submitted to the Commission a multi-party settlement agreement for PG&E's 2020 GRC, which included provisions addressing PG&E's CWSP for the period 2020-2022. PG&E's 2020 WMP reflects many of the wildfire mitigations as described in the 2020 GRC. However, wildfire risk is not static, nor are PG&E's efforts to mitigate that risk. Since the 2020 WMP reflects PG&E's updated plans, PG&E intends to work with regulators and other parties to assure that costs are clearly identified and tracked through the proposed two-way balancing accounts for CWSP and VM. These balancing account mechanisms and associated audit and reporting requirements give PG&E adequate resources and flexibility to address evolving needs related to wildfire

mitigation, yet provide full transparency and accountability into how PG&E spends CWSP-related and VM funds.

The 2020 WMP, Utility Survey and related attachments below are being submitted as part of a new process led by the CPUC Wildfire Safety Division (WSD). For this first iteration of the new format and approach, PG&E has attempted to provide all data, explanations and information requested as completely as possible, but we acknowledge that not all elements are complete. Consistent with the WSD's direction that this is an evolving process, PG&E will continue learning, iterating and improving our wildfire risk reduction efforts, in conjunction with stakeholders and partners, pursuing our shared goal to further reduce wildfire risks in the years ahead.

C. Conclusion

The risk of catastrophic wildfires in California has increased dramatically over the past few years, and PG&E has transformed how we respond to that risk. We hold the safety of our customers, communities and workforce as our highest priority and have committed the Company to the effort of reducing the frequency, scope and impact of utility-caused wildfires. We have been working with many partners and parties to identify and implement effective methods to reduce wildfire ignitions and risk, reduce the impacts of PSPS events used to limit wildfire ignitions under extreme fire risk conditions, and to help our communities cope with these changes and challenges. PG&E will continue to implement and improve these efforts, working in concert with those we serve to lower the wildfire risk for all.

**PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION PLAN
SECTION 1
PERSONS RESPONSIBLE FOR EXECUTING THE WMP**

1. Persons Responsible for Executing the Wildfire Mitigation Plan

Provide an accounting of the responsibilities of the responsible person(s) executing the plan, including:

1. Executive level with overall responsibility
2. Program owners specific to each component of the plan

Ensure that the plan components described in (2) include an accounting for each of the Wildfire Mitigation Plan (WMP) sections and subsections.

The following individuals have responsibilities for execution of Pacific Gas and Electric Company's (PG&E) 2020 WMP.

Executive Level Responsibility:

- Michael Lewis, Senior Vice President, Electric Operations

Program Owners for Each Component of Plan:

Plan Component	Program Owner	WMP Section
Plan Objective, Wildfire Mitigation Strategy, WMP Implementation	Matthew Pender	2.5, 4.1, 5.1, 5.2, 5.3, 5.10, 5.11, 6.6
Metrics, Risk Analysis, Asset Allocation	Mark Esguerra	2.1-2.4, 2.6, 2.7, 3.2, 3.4.2, 3.4.3, 4.2, 4.2.1, 4.3, 4.4, 5.3.1, 5.3.3, 5.3.7, 5.3.8, 5.4, 5.6.1, 6.2, 6.5
PSPS, Situational Awareness, Grid Operations	Mark Quinlan	3.1, 3.3, 3.4.1, 5.3.2, 5.3.6, 5.3.9, 5.6.2, 6.1, 6.3
Vegetation Management	Michael Ritter	5.3.5
Mapping, Data Governance	Jay Singh	2.7, 3.4.1, 5.3.7, 6.4
Execution Risk	Jonathan Seager	5.5
Inspections	Mary Hvistendahl	5.3.4
Customer Support	Megan Ardell	5.3.9
Public Partnerships	Mary Ellen Ittner	5.3.9

Verification

I am an officer of the applicant corporation herein, and am authorized to make this verification on its behalf. The statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters I believe them to be true.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 01/27/2021 at Fontana, California.
(Date) (Name of city)

Michael O. Jones SVP Electric Operations PG&E
(Signature and Title of Corporate Officer)

1.1 Explanation of Data and Formatting

The WMP Guidelines provided include thorough tables for the utilities to complete as part of their 2020 WMPs.¹ The 2020 WMP represents an entirely new format and approach to communicating about wildfire risk mitigation activities compared to what was submitted, reviewed, and approved in the 2019 WMP process. Driven by new legislation (e.g., Assembly Bill 1054) and the direction of the Wildfire Safety Division (WSD), this new format is itself an ongoing evolution in how the state discusses and reviews utility wildfire risk mitigation activities.

PG&E has attempted to the best of its ability to provide the information requested in the time allotted. Due to the relatively condensed period in which to complete the 2020 WMP in response to the WMP Guidelines and subsequent clarifications, there may be some areas where PG&E is unable to provide the requested data.

To assist the WSD and others in understanding PG&E's 2020 WMP, we are providing the following clarifications and explanations.

Additional Data

The WMP Guidelines direct the utilities to work with federal, state, and local agencies, stakeholders, and partners to collect or compile information that the utility has not collected and could not ascertain. Where the utility is unable to obtain information from third parties, the WMP Guidelines direct the utility to identify alternative data points. While PG&E was able to obtain supplemental information from other entities such as California Department of Forestry and Fire Protection, PG&E was not able to reach out to or obtain data from third parties in all situations.

Use of WMP Metrics

PG&E has provided WMP metrics and data requested by WSD. However, providing these metrics should not be interpreted as agreement that all of the requested metrics are useful or appropriate for the purposes of analyzing risk. For example, in some cases where WSD asked for 5-year historical averages, use of that average may not adequately reflect either a strong upward or downward trend, or extreme year-over-year variability.

Instructions and Additional Tables and Figures

To provide context to help understand the tables and narrative, PG&E has included the instructions from the WMP Guidelines in *italics* at the beginning of each section and table in the WMP.

In addition to the tables set forth in the WMP Guidelines, PG&E is also providing additional tables to explain various additional data or calculations that PG&E performed to complete the required tables. PG&E has included only the required WMP Guideline

¹ The WMP Guidelines were included as Attachment 1 to the *Administrative Law Judge's Ruling on Wildfire Mitigation Plan Templates and Related Material and Allowing Comment*, Rulemaking 18-10-007 (December 16, 2019).

tables, not the PG&E-specific tables, in the excel files that it is posting with the WMP. The additional PG&E-specific tables are identified in the following format in the narrative:

TABLE PG&E-SECTION#-TABLE#.

For example, the second PG&E-specific table in Section 3 of the WMP would be TABLE PG&E-3-2.

Likewise, where PG&E has provided figures to supplement the narrative, these PG&E-specific figures are identified in the same format:

FIGURE PG&E-SECTION#-FIGURE#.

For example, the first figure in Section 2 of the WMP would be FIGURE PG&E-2-1.

Definition of Terms

Generally, PG&E relies upon the Glossary provided in the WMP Guidelines as a reference source for terminology used in the tables. Where PG&E uses other non-common terms or phrases, PG&E has attempted to define these terms in the narrative accompanying the charts or sections. In addition, please note that in contrast to the use of the term "transmission" in the WMP Guidelines, PG&E defines electric transmission lines as those lines 60 kilovolt and above.

Attachments

PG&E is providing the following attachments to its 2020 WMP on its website:

- Attachment 1: All Tables Required by the WMP Guidelines
- Attachment 2: List of Community Resource Centers per Section 5.6.2.2
- Attachment 3: List of Critical Facilities per Section 5.6.2.4 (CONFIDENTIAL)
- Attachment 4: PG&E's Utility Survey Responses
- Attachment 5: Additional Detail on PG&E's Utility Survey Responses
- Attachment 6: GIS Files

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION PLAN
SECTION 2
METRICS AND UNDERLYING DATA

2 Metrics and Underlying Data

Instructions: Report performance on the following progress and outcome metrics within the utility's service territory over the past five years. Where a utility does not collect its own data for a given metric, that utility shall work with the relevant sources to collect the information for its service territory, and clearly identify the owner and dataset used to provide the response in "Comments" column.

Progress metrics, listed below, track how much utility wildfire mitigation activity has managed to change the conditions of utility wildfire risk exposure in terms of drivers of ignition probability.

Outcome metrics measure the performance of a utility and its service territory in terms of both leading and lagging indicators of wildfire risk, PSPS risk, and other direct and indirect consequences of wildfire and PSPS, including the potential unintended consequences of wildfire mitigation work.

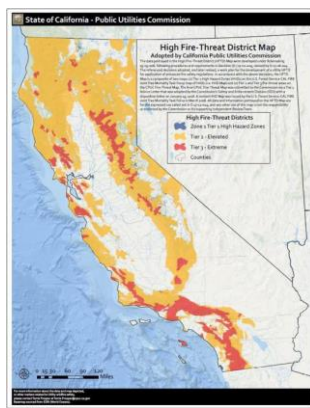
In the 2019 WMPs, utilities proposed sets of "program targets" that enable tracking implementation of proposed wildfire mitigation activities against the scope of those activities as laid out in the WMPs but do not track the efficacy of those activities. Utilities shall continue to report program targets, however, the primary use of these will be to gauge follow-through on WMPs while recognizing that some WMP initiatives should be adjusted after plan submittal based on new information and lessons learned.

2.1 Lessons Learned: How Tracking Metrics on the 2019 Plan Has Informed the 2020 Plan

Describe how the utility's plan has evolved since the 2019 WMP submission. Outline any major themes and lessons learned from the 2019 plan and subsequent implementation of the initiatives. In particular, focus on how utility performance against the metrics used has informed the utility's 2020 WMP.

PG&E is continuously reviewing, evaluating, and modifying as needed the programs described in PG&E's 2019 Wildfire Mitigation Plan (2019 WMP) and now in this 2020 Wildfire Mitigation Plan (2020 WMP). PG&E's 2019 WMP focused on measures that would reduce the risk that PG&E facilities would cause wildfires and create public safety risks, specifically in High Fire Threat District (HFTD) areas. HFTD areas are defined by the map adopted by the California Public Utilities Commission (CPUC or Commission) in January 2018. The HFTD map is reprinted below in Figure PG&E-2-1.

FIGURE PG&E-2-1: CPUC 2018 FIRE-THREAT MAP



HFTD areas include:

- Tier 3 – Extreme Fire Risk areas
- Tier 2 – Elevated Fire Risk areas
- Zone 1 – United States Forest Service (USFS) and CAL FIRE Tree Mortality High Hazard areas not included in Tier 3 or Tier 2.

Over 50% of PG&E's service territory is in HFTD areas. Thus, PG&E's 2019 WMP focused on mitigating fire threat in these areas. The major themes and lessons learned from the 2019 WMP are as follows:

- The execution of the combined 2019 WMP was successful in mitigating catastrophic wildfires in the PG&E service territory;
- Ignitions were reduced by 24% from 2018;
- The increased coverage from installed weather stations improved the accuracy of meteorology models and the capabilities of the Wildfire Safety Operations Center (WSOC);

- Extreme hazard weather conditions were severe during the 2019 fire season, and Public Safety Power Shutoff (PSPS) events were highly effective at reducing the risk of vegetation or other flammable items contacting live wires and starting fires; and
- PG&E gained a better appreciation of the burden PSPS places upon affected customers and communities, and is committed to reducing the frequency, scope, and duration of PSPS events.

The 2019 WMP metrics focused on the completion of inspections and the resolution of high priority identified items, as well as the implementation of wildfire risk mitigation activities such as enhanced vegetation management and system hardening. PG&E provided to the Commission and stakeholders on January 15, 2020 in *Pacific Gas and Electric Company's Updated Progress Report of Wildfire Mitigation Plan* a detailed summary of the initiatives, commitments, and metrics in the 2019 WMP and how PG&E performed.¹

Based on its experience preparing and implementing the 2019 WMP, as well as feedback from the Commission and stakeholders, PG&E has expanded focus of its wildfire safety programs. PG&E's 2020 WMP is focused on three key areas: reducing the potential for fires to be started by electrical equipment, reducing the potential for fires to spread, and minimizing the frequency, scope and duration of PSPS events. The 2020 WMP metrics are more focused on the system performance areas that the analysis and inspections during 2019 indicate are the key measures for electric system safety from a wildfire perspective.

For example, the 2019 Wildfire Safety Inspection Program (WSIP) resulted in essential findings about components in HFTD areas that could pose a risk of fire ignition. The cutting-edge use of aerial technology in combination with visual inspections resulted the ability to address potential areas of failure in a timely fashion. In addition to PG&E's routine maintenance program, in 2019 PG&E performed new, enhanced inspections of all transmission, distribution, and substation structures in the HFTD areas within its service area. PG&E's 2019 WSIP included all approximately 750,000 poles and structures in the HFTD areas and identified needed maintenance and replacement. Building on this foundation, PG&E is incorporating the enhanced inspection processes and tools into routine compliance inspection and maintenance and using risk-informed maintenance cycles going forward. For example, in 2020, PG&E will use this methodology in conducting annual inspections of all facilities in HFTD Tier 3 areas and one-third of Tier 2 facilities.

Similarly, PG&E has modified the scope of its Enhanced Vegetation Management (EVM) Program for 2020. In 2019, PG&E's contractors and crews managed to surpass the ambitious goal of nearly 2,500 miles of EVM, while including assessments and re-work under the scrutiny of both 100% work validation and a quality assurance program. In 2020, PG&E currently plans to use EMV on approximately 1,800 line-miles in order to reflect insights gained from the 2019 WMP efforts and allow PG&E to most effectively

¹ The 2019 WMP progress report is available on the CPUC's website at: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/R1810007%20PGE%20WMP%20Status%20Update%201-15-20.pdf.

manage resources. For example, PG&E's experience in 2019 has led PG&E to shift some EVM work from distribution to lower voltage transmission lines to reduce the impact of PSPS events. After the 2019 wildfire season, PG&E has a better understanding of the burden PSPS events place on customers. One major factor on the scope of PSPS events is the number of transmission lines included within the footprint of the event, as transmission lines have outsized impacts on downstream communities that may otherwise be outside of the PSPS area. To reduce that impact, PG&E is adding a new vegetation management program in the 2020 WMP, which will focus on expanding transmission right of way clearing for 60, 70, and 115 kV transmission lines. This will help to minimize the frequency, scope, and duration of PSPS events.

These are just two examples of how PG&E's performance against metrics in the 2019 WMP have helped inform the 2020 WMP. Each of the 2020 WMP program, including learnings from 2019, are described in more detail in Section 5. By evaluating PG&E's experience implementing wildfire mitigation measures, incorporating feedback from customers, communities, and industry experts, and building upon PG&E's programs, PG&E will continue to enhance and improve PG&E's wildfire mitigation programs to better prevent wildfires from occurring and protect the public.

2.2 Recent Performance on Progress Metrics, Last 5 Years

Instructions for Table 1:

Report performance on the following metrics within the utility's service territory over the past five years. Where the utility does not collect its own data on a given metric, the utility shall work with the relevant state agencies to collect the relevant information for its service territory, and clearly identify the owner and dataset used to provide the response in the "Comments" column.

TABLE 1-1: RECENT PERFORMANCE ON PROGRESS METRICS, LAST 5 YEARS

#	Progress metric name	Annual performance					Unit(s)	Comments
		2015	2016	2017	2018	2019		
1	Grid condition findings from inspection – Distribution	0.434553	0.580677	0.591185	0.577253	6.910547	Number of Level 1, 2, and 3 findings per mile of circuit in HFTD, and per total miles of circuit for each of the following inspection types:	No Comments
		0.000118	0.000236	0.041991	0.009524	0.014522	Number of level 1 findings (A tags) per mile of circuit in HFTD (Zone 1, Tier 2 & Tier 3 combined)	
		0.013066	0.009327	0.013656	0.022117	0.175954	Number of level 2 findings (B tags) per mile of circuit in HFTD (Zone 1, Tier 2 & Tier 3 combined)	
		0.421370	0.571114	0.535537	0.545612	6.720071	Number of level 3 findings (E+F tags) per mile of circuit in HFTD (Zone 1, Tier 2 & Tier 3 combined)	
		0.000984	0.001535	0.058284	0.234986	0.035931	Number of level 1 findings (A tags) per mile of total circuit	
		0.062810	0.053483	0.070327	0.085006	0.314207	Number of level 2 findings (B tags) per mile of total circuit	
		1.395317	1.704329	1.451082	1.383038	7.976348	Number of level 3 findings (E+F tags) per mile of total circuit	
2	Vegetation clearance findings from inspections	2362	2792	3217	4815	37807	Trees identified as being currently, or at risk in the near future, of being out of compliance	PG&E does not track the precise data requested; the closest available estimate has been provided. (See comment below tables)
		1,545,000	1,545,000	1,545,000	1,545,000	1,545,000	Total # of Overhead Distribution Primary Spans in the system	
		0.20%	0.20%	0.20%	0.30%	2.40%	Estimated Percentage of electric distribution spans with non-compliant clearance	
3	Extent of grid modularization	N/A	N/A	N/A	N/A	1.767	HFTD All Devices/Mile	*Sectionalizing devices: defined as Overhead Switches, Fuses, Reclosers, Sectionalizers, TripSavers, FuseSavers. *Circuit miles? Defined as all overhead primary lines and excludes underground primary lines. Calculated data is defined as Overhead Devices per Overhead Mile
		N/A	N/A	N/A	N/A	0.084	HFTD SCADA Devices/Mile	
		N/A	N/A	N/A	N/A	3.231	Non-HFTD All Devices/Mile	
		N/A	N/A	N/A	N/A	0.126	Non-HFTD SCADA Devices/Mile	
4	4 Data collection and reporting	-	-	-	-	60.2%	Percent of data requested in SDR and WMP collected in initial submission	The 2019 percent collected is for the data provided in the WMP Tables 1-31 (submitted on 2/7/2020) and does not include the SDR. Data considered to be N/A or TBD for any reason, for example not currently available or not feasible, is included/was not removed from the calculation.

Item 2 Comments (1-1 Distribution) – PG&E does not track the precise data requested as PG&E's vegetation management data is generally tracked by tree. Therefore the closest available data has been provided with an estimated translation to the "Percentage of right-of-way with noncompliant clearance" data that was requested. PG&E vegetation management pre-inspectors identify a tree that is currently violating minimum clearance distances, or may violate minimum clearance in the near future, with a special designation of being a "Hazard Notification" (HN). Not all HNs represent actively non-compliant trees, as in many cases the tree is currently compliant but may be at risk of violating minimum clearances before the normal tree work cycle can be completed. Nonetheless, HNs are the best estimate PG&E has for the number of trees that were identified as being inside or near the minimum clearance requirements and have been provided above as the "Trees identified as being currently, or at risk in the near future, of being out of compliance" data.

(1) This estimate for the number of electric overhead spans has been determined by assuming an average span length (distance between poles) of 275 feet. Therefore the ~80,560 miles of overhead distribution circuit miles (425,356,800 feet) divided by 275 feet per span results in 1,546,752 total spans, or ~1,545,000 for the purposes of this estimate.

TABLE 1-2: RECENT PERFORMANCE ON PROGRESS METRICS, LAST 5 YEARS

#	Progress metric name	Annual performance					Unit(s)
		2015	2016	2017	2018	2019	
1	Grid condition findings from inspection – Transmission	0.523258	0.687421	0.419910	0.926878	10.638552	Number of Level 1, 2, and 3 findings per mile of circuit in HFTD, and per total miles of circuit for each of the following inspection types:
2		0.018100	0.005792	0.009774	0.003620	0.037466	Number of level 1 findings (A tags) per mile of circuit in HFTD (Zone 1, Tier 2 & Tier 3 combined)
3		0.037828	0.021357	0.027873	0.030226	0.873484	Number of level 2 findings (B tags) per mile of circuit in HFTD (Zone 1, Tier 2 & Tier 3 combined)
4		0.467330	0.660271	0.382262	0.893032	9.727602	Number of level 3 findings (E+F tags) per mile of circuit in HFTD (Zone 1, Tier 2 & Tier 3 combined)
5		0.038069	0.011862	0.014014	0.006179	0.030731	Number of level 1 findings (A tags) per mile of total circuit
6		0.059697	0.057710	0.061683	0.061021	0.416055	Number of level 2 findings (B tags) per mile of total circuit
7		0.565352	0.543614	0.436138	0.711062	4.011200	Number of level 3 findings (E+F tags) per mile of total circuit

Comments for Table 1:

- **Item 1.a. Description - Grid condition findings from inspection – Transmission (T) and Distribution (D)**

Item 1.a. Comments-The following TABLE PG&E-2-1 summarizes PG&E Distribution overhead (OH) and Transmission OH line mile data, which was used throughout this WMP, including to calculate the per line mile data:

TABLE PG&E-2-1: PG&E OH Line Miles

HFTD Area	D-OH Line Miles (approx.)	T-OH Line Miles (approx.)
Tier 3	7,100	1,300
Tier 2	18,200	4,200
Zone 1	110	25
Non-HFTD Area	55,300	12,600
Tier 1		
Total	80,710	18,125

2.3 Recent Performance on Outcome Metrics, Annual and Normalized for Weather, Last 5 Years

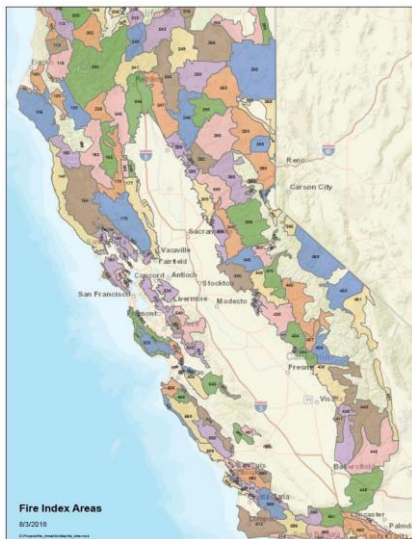
Instructions for Table 2:

Report performance on the following metrics within the utility's service territory over the past five years. Where the utility does not collect its own data on a given metric, the utility shall work with the relevant state agencies to collect the relevant information for its service territory, and clearly identify the owner and dataset used to provide the response in "Comments" column.

Provide a list of all types of findings and number of findings per type, in total and in number of findings per circuit mile.

Various Tables in the WMP, including Items 1.b., 1.d., 3.b., 3.d., 4.b., 7.b., 8.b., 9.b., 10.b., and 11.b., of TABLE 2 and Metrics 1A, 1B, 2A, 2B, 3A, 3BA, 5A, and 5B of Table 3-1, seek event or incident data per Red Flag Warning (RFW) Days or normalized by RFW circuit mile day per year. In order to perform these calculations, PG&E derived the RFW Day Overhead (OH) circuit miles for transmission and distribution as follows: First, PG&E identified every day when there was a RFW for a portion of PG&E's service area. Then PG&E determined whether each RFW covered one or more Fire Impact Areas (FIA). The FIAs represent geographic areas within PG&E's service area across Tier 2 and 3 of the CPUC's HFTD map where PG&E has overhead electric transmission or distribution equipment. PG&E Meteorology determines the fire potential index for each FIA based on fire weather and fuels. Figure PG&E-2-2, below, represents a map of the FIAs.

FIGURE PG&E-2-2: FIRE IMPACT AREA (FIA) MAP



For each FIA covered by a RFW, PG&E determined the associated overhead distribution and transmission circuit miles for each FIA and the total number of hours of that RFW. (Since the overhead system is represents a greater fire risk in comparison to an underground system, overhead T&D circuit miles were used in this calculation instead of the combined overhead and underground T&D circuit miles. In addition, this distinction allows these same values to be used when normalizing the T&D wire down event results for Item 1.d. Moreover, the area covered by a RFW may be larger than the identified FIAs. However, since the combination of FIAs is aligned with the Tier 2 and Tier 3 HFTD areas, PG&E has quantified the RFW Days for the Tier 2 and Tier 3 HFTD areas, which represent the greatest wildfire risk.) PG&E then determined the RFW day value by dividing total RFW hours by 24 hours. PG&E then multiplied the total distribution and transmission circuit miles for each FIA by the total RFW days for

that FIA and summed the totals for all FIAs to arrive at the total overhead circuit miles within HFTD Tier 2 and 3.

The resulting RFW circuit mile (within HTFD Tier 2 and Tier 3) day per year values are set forth in Table PG&E-2-2:

TABLE PG&E-2-2: Annual Days RFW Circuit Mile				
RFW Day - OH Circuit Miles (T&D Combined)				
2015	2016	2017	2018	2019
63,304	89,832	471,375	522,855	360,281

PG&E supports this methodology to determine the RFW circuit mile day per year values. However, to most accurately use this data and metrics to evaluate changes in wildfire risk, this data should not be applied against system-wide, annual data. Instead the appropriate, consistent data to be normalized against RFW Days or circuit mile day per year comprises data for events or incidents within the wildfire threat areas, as reflected by the CPUC's HFTD map (Figure PG&E-2-1, above), and data for events or incidents that occur during RFW hours. Otherwise the evaluation risks capturing inapplicable events and throwing off the calculation. Wildfire risks are differentiated across California. PG&E's 2020 WMP reflects that differentiation by tailoring its wildfire mitigation programs to reduce the fire risks within the areas identified as having the most significant fire risks in the CPUC's HFTD map, the HFTD Tier 2 and Tier 3 areas (as shown in Figure PG&E-2-1, above). Therefore, the effectiveness of these programs should be based on both the past and future performance within the HFTD Tier 2 and Tier 3 areas.

Likewise, since weather will vary, these results should also be normalized based on the weather, such as by using the hours involved with RFW Days. Otherwise the calculation will include events that do not reflect or affect wildfire risk. For example, wires down events that occur in Tier 1 areas, such as cities, would not likely increase wildfire risk. Likewise, wires down events that occur in the middle of a wet winter due to a major rainstorm also would not increase wildfire risk. In other words, when normalizing the result by RFW Days, the measured events should be those that occur during RFW hours within the HFTD Tier 2 and Tier 3 areas, not rather than normalizing for all events that occur within the entire service territory. While PG&E has attempted to perform the RFW calculations and normalizations, as required by the tables, PG&E cautions against using these calculations without further limiting the data to be normalized to events or incidents within the HTFD areas that occur during RFD hours.

TABLE 2: RECENT PERFORMANCE ON OUTCOME METRICS, LAST 5 YEARS

Metric type	#	Outcome metric name	Annual performance					Unit(s) ¹	Comments
			2015	2016	2017	2018	2019		
1. Near misses	1.a.	Number of all events (such as unplanned outages, faults, conventional blown fuses, etc.) that could result in ignition, by type according to utility-provided list (total)	D = 37,072 T = 1,178	D = 36,244 T = 835	D = 49,442 T = 1,269	D = 33,122 T = 944	D = 44,568 T = 1,537	Number per year Note: The D indicates the Distribution events and the T indicates Transmission events. The total below the double lines represent the total T&D events.	See comments section.
			38,250	37,079	50,711	34,066	46,105		
	1.b.	Number of all events (such as unplanned outages, faults, conventional blown fuses, etc.) that could result in ignition, by type according to utility-provided list (normalized)	0.6042	0.4128	0.1076	0.0652	0.1280	Number per RFW circuit mile day per year	See comments section.
	1.c.	Number of wires down (total)	D = 3,788 T = 65	D = 4,285 T = 70	D = 7,244 T = 44	D = 3,532 T = 96	D = 6,280 T = 47	Number of wires down per year Note: The D indicates the Distribution events and the T indicates Transmission events. The total below the double lines represent the total T&D events.	See comments section.
			3,853	4,355	7,288	3,628	6,327		
	1.d.	Number of wires down (normalized)	0.06087	0.04848	0.01546	0.00694	0.01756	Number per RFW circuit mile day per year	See comments section.

TABLE 2: RECENT PERFORMANCE ON OUTCOME METRICS, LAST 5 YEARS (CONTINUED)

Metric type	#	Outcome metric name	Annual performance					Unit(s)	Comments
			2015	2016	2017	2018	2019		
2. Utility inspection findings	2.a.	Number of Level 1 findings that could increase the probability of ignition discovered per circuit mile inspected	EC 3 LC 0	EC 6 LC 3	EC 1007 LC 46	EC 172 LC 25	EC 339 LC 140	Average number of Level 1 findings that could increase the probability of ignition discovered by all inspections per circuit mile per year	EC represents Distribution notifications, and LC represents Transmission notifications. Level 1 = Priority A notifs HFTD Notifs only, for FDAs that have been identified as time-based deterioration field conditions.
	2.b.	Number of Level 2 findings that could increase the probability of ignition discovered per circuit mile inspected	EC 6513 LC 12	EC 10395 LC 281	EC 9104 LC 787	EC 10578 LC 2580	EC 173229 LC 32177	Average number of Level 2 findings that could increase the probability of ignition discovered by all inspections per circuit mile per year	Level 2 = B & E Priority notifs. HFTD Notifs only, for FDAs that have been identified as time-based deterioration field conditions.

TABLE 2: RECENT PERFORMANCE ON OUTCOME METRICS, LAST 5 YEARS (CONTINUED)

Metric type	#	Outcome metric name	Annual performance					Unit(s)	Comments
			2015	2016	2017	2018	2019		
	2.c.	Number of Level 3 findings that could increase the probability of ignition discovered per circuit mile inspected	EC 4526 LC 6	EC 4354 LC 20	EC 4851 LC 68	EC 3848 LC 491	EC 1999 LC 343	Average number of Level 3 findings that could increase the probability of ignition discovered by all inspections per circuit mile per year	Level 3 = Priority F notifs. HFTD Notifs only, for FDAs that have been identified as time-based deterioration field conditions.
3. Customer hours of PSPS and other outages	3.a.	Customer hours of planned outages including PSPS (total)	1,400,185	1,390,308	1,513,383	4,015,315	101,222,207	Total customer hours of planned outages per year	See comments section.
	3.b.	Customer hours of planned outages including PSPS (normalized)	22.12	15.48	3.21	7.68	280.95	Total customer hours of planned outages per RFW circuit mile day per year	See comments section.
	3.c.	Customer hours of unplanned outages, not including PSPS (total)	11,961,889	9,745,978	32,897,043	24,597,247	28,981,976	Total customer hours of unplanned outages per year	See comments section.
	3.d.	Customer hours of unplanned outages, not including PSPS (normalized)	188.96	108.49	69.79	47.04	80.44	Total customer hours of unplanned outages per RFW circuit mile day per year	See comments section.
	3.e.	Increase in System Average Interruption Duration Index (SAIDI)	- 2.1	- 25.2	252.4	- 64.9	1,088.3	Change in minutes compared to the previous year	See comments section.

TABLE 2: RECENT PERFORMANCE ON OUTCOME METRICS, LAST 5 YEARS (CONTINUED)

Metric type	#	Outcome metric name	Annual performance					Unit(s)	Comments
			2015	2016	2017	2018	2019		
4. Utility ignited wildfire fatalities	4.a.	Fatalities due to utility-ignited wildfire (total)	2	0	22	85	0	Number of fatalities per year	See comments section.
	4.b.	Fatalities due to utility-ignited wildfire (normalized)	0.000032	0	0.000047	0.000163	0	Number of fatalities per RFW circuit mile day per year	See comments section.
5. Accidental deaths resulting from utility wildfire mitigation initiatives	5.a.	Deaths due to utility wildfire mitigation activities (total)	–	–	–	0	1	Number of fatalities per year	Fatality represents a contractor accident during WSIP work.
6. OSHA-reportable injuries from utility wildfire mitigation initiatives	6.a.	OSHA-reportable injuries due to utility wildfire mitigation activities (total)	–	–	–	0	28	Number of OSHA-reportable injuries per year	
	6.b.	OSHA-reportable injuries due to utility wildfire mitigation activities (normalized)	–	–	–	0	0.894	Number of OSHA-reportable injuries per year per 1000 line miles of grid	Per 1000 miles of HFTD grid
7. Value of assets destroyed by utility-ignited wildfire, listed by asset type	7.a.	Value of assets destroyed by utility-ignited wildfire (total)	\$895.5M	\$880k	\$25.5B	\$36k	\$39k	Dollars of damage or destruction per year	See comments section.
	7.b.	Value of assets destroyed by utility-ignited wildfire (normalized)	\$14,146	\$9.79	\$54.01k	\$0.69	\$0.11	Dollars of damage or destruction per RFW circuit mile day per year	See comments section.
8. Structures damaged or destroyed by utility-ignited wildfire	8.a.	Number of structures destroyed by utility-ignited wildfire (total)	965	0	2,299	18,805	374	Number of structures destroyed per year	See comments section.
	8.b.	Number of structures destroyed by utility-ignited wildfire (normalized)	0.015244	0	0.004877	0.035966	0.0010381	Number of structures destroyed per RFW circuit mile day per year	See comments section.

TABLE 2: RECENT PERFORMANCE ON OUTCOME METRICS, LAST 5 YEARS (CONTINUED)

Metric type	#	Outcome metric name	Annual performance					Unit(s)	Comments
			2015	2016	2017	2018	2019		
9. Acreage burned by utility-ignited wildfire	9.a.	Acreage burned by utility-ignited wildfire (total)	1,690	1,102	170,455	167,162	79,950	Acres burned per year	See comments section.
	9.b.	Acreage burned by utility-ignited wildfire (normalized)	0.026697	0.012267	0.361612	0.319710	0.221910	Acres burned per RFW circuit mile day per year	See comments section.
10. Number of utility wildfire ignitions	10.a.	Number of ignitions (total) according to existing ignition data reporting requirement	12	9	35	20	21	Number per year	See comments section.
	10.b.	Number of ignitions (normalized)	0.0001896	0.0001002	0.0000743	0.0000383	0.0000583	Number per RFW circuit mile day per year	See comments section.
	10.c.	Number of ignitions in HFTD (subtotal)	4	6	18	20	5	Number in HFTD per year	See comments section.
	10.c.i.	Number of ignitions in HFTD Zone 1	0	0	0	13	0	Number in HFTD Zone 1 per year	See comments section.
	10.c.ii.	Number of ignitions in HFTD Tier 2	2	5	14	6	5	Number in HFTD Tier 2 per year	See comments section.
	10.c.iii.	Number of ignitions in HFTD Tier 3	2	1	4	1	0	Number in HFTD Tier 3 per year	See comments section.
	10.d.	Number of ignitions in HFTD (subtotal, normalized)	0.0000632	0.0000668	0.0000382	0.0000383	0.0000139	Number in HFTD per RFW circuit mile day per year	See comments section.
	10.d.i.	Number of ignitions in HFTD Zone 1 (normalized)	0	0	0	0.0000249	0	Number in HFTD Zone 1 per RFW circuit mile day per year	See comments section.
	10.d.ii.	Number of ignitions in HFTD Tier 2 (normalized)	0.0000316	0.0000557	0.0000297	0.0000115	0.0000139	Number in HFTD Tier 2 per RFW circuit mile day per year	See comments section.

TABLE 2: RECENT PERFORMANCE ON OUTCOME METRICS, LAST 5 YEARS (CONTINUED)

Metric type	#	Outcome metric name	Annual performance					Unit(s)	Comments
			2015	2016	2017	2018	2019		
	10.d.iii.	Number of ignitions in HFTD Tier 3 (normalized)	0.0000316	0.0000111	0.0000085	0.0000019	0	Number in HFTD Tier 3 per RFW circuit mile day per year	See comments section.
	10.e.	Number of ignitions in non-HFTD (subtotal)	8	3	17	0	16	Number in non-HFTD per year	See comments section.
	10.f.	Number of ignitions in non-HFTD (normalized)	0.0001264	0.0000334	0.0000361	0	0.0000444	Number in non-HFTD per RFW circuit mile day per year	See comments section.
11. Critical infrastructure impacted	11.a.	Critical infrastructure impacted by PSPS	0	0	0	23,257	577,060	Number of critical infrastructure (in accordance with D.19-05-042) locations impacted per hour multiplied by hours offline per year	
	11.b.	Critical infrastructure impacted by PSPS (normalized)	0	0	0	< 0.01	1.60	Number of critical infrastructure (in accordance with D.19-05-042) locations impacted per hour multiplied by hours offline per RFW circuit mile day per year	

Notes for Table 2:

- 1. The chart in the excel files will include the totals only, no the individual T and D numbers.

Comments for Table 2: Item 1 - Near Misses

- Item 1.a. Description** - Number of all events (such as unplanned outages, faults, conventional blown fuses, etc.) that could result in ignition, by type according to utility-provided list (total) – Number per year

Item 1.a. Comments – Determining whether a specific event could result in an ignition depends upon a wide variety of factors, including the nature of the event itself and prevailing environmental conditions (e.g., weather, ground moisture level, time of year). As PG&E does not have complete information to make this determination for each event, PG&E relies upon the following proxy to derive these numbers. Most distribution outages (momentary and sustained) and transmission line path interruptions typically involve a fault condition. Thus, for purposes of this response, PG&E assumes all distribution outages and transmission interruptions could potentially result in an ignition, regardless of other prevailing conditions. PG&E has utilized its historical outage event information to provide the results used for item 1.a., which includes all distribution momentary and sustained outages and transmission line path interruptions for each year. The following should also be noted:
 - Planned/Wildfire Mitigation outages and PSPS events generally do not involve fault conditions and have been excluded from these results for distribution. However, the numbers for transmission in Table 2 do include PSPS events, and as needed can be excluded using Table 11.2 where these PSPS events are itemized as “Other-safety clearance.”
 - Further details of these events are outlined in Tables 11.1 (distribution) and 11.2 (transmission).
 - Since the distribution outage data was downloaded in early January 2020, all 2019 outage results do not have the benefit of PG&E’s electric outage review process that is typically performed a few weeks after the year end, so the final reviewed numbers may vary from the numbers reported here. However, the transmission data have been reviewed and no further changes are anticipated at the time of this submittal.
- Item 1.b. Description** - Number of all events (such as unplanned outages, faults, conventional blown fuses, etc.) that could result in ignition, by type according to utility-provided list (total) – Number per Red Flag Warning (RFW) circuit mile day per year

Item 1.b. Comments –The provided data for Item 1.b. was derived by taking the annual data provided in Item 1.a. and dividing by a corresponding/calculated number of RFW circuit mile day per year value as summarized in Table PG&E-2-2 below. As discussed above in the introduction to Table 2, however, PG&E does not recommend normalizing the data in Item 1.a., which covers PG&E’s entire service area across the entire year, by the numbers in Table PG&E-2-2.

TABLE PG&E-2-2: ANNUAL RFW DAYS – OH CIRCUIT MILES (T&D COMBINED)

RFW Day - OH Circuit Miles (T&D Combined)				
2015	2016	2017	2018	2019
63,304	89,832	471,375	522,855	360,281

- **Item 1.c. Description** - Number of wires down (total)

Item 1.c. Comments - PG&E has utilized its historical outage event information to provide the results used for item 1.c., which includes both distribution and transmission wire down events and which represents a subset of the Item 1.a. results. By PG&E's current definition, distribution wire down events result in an actual outage event on the primary distribution system. However, for the purpose of providing the data used for this item, PG&E has also included secondary and service related wire down events reported within its Integrated Logging Information System-Operations Data Base (ILIS-ODB) outage database.

- **Item 1.d Description** - Number of wires down (normalized)

Item 1.d. Comments - The provided data for Item 1.d. was derived by taking the annual results noted as Item 1.c. and dividing by the corresponding/calculated annual number of RFW circuit mile day per year values as summarized in Table PG&E-2-2 above. As mentioned, these values are based on the T&D overhead circuit miles and are therefore better aligned with the provided T&D overhead wire down events.

Comments for Table 2: Item 3 – Customer hours of PSPS and other outages

- **Item 3.a. Description** - Customer hours of planned outages including PSPS (total)

Item 3.a. Comments – PG&E's ILIS-ODB outage database was used to provide the combined customer hours of both planned and PSPS outage events in the table. It should be noted that these results are a summary of the entire year and that the planned outages are not related to the RFW Days.

- **Item 3.b. Description** - Customer hours of planned outages including PSPS (normalized)

Item 3.b. Comments - The provided data for Item 3.b. was derived by taking the annual results noted as Item 3.a. and dividing by a corresponding/calculated annual number of RFW circuit mile day per year values as summarized in Table PG&E-2-2 above. As previously mentioned, the Table PG&E-2-2 values are based on the T&D overhead circuit miles.

- **Item 3.c. Description** - Customer hours of unplanned outages, not including PSPS (total)

Item 3.c. Comments - PG&E's ILIS-ODB data base was used to provide the customer hours of unplanned outages, not including PSPS outage events (total). It should be noted that these results are a summary of the entire year and that not all of the unplanned outages are related to the RFW Days.

- Item 3.d. Description** - Customer hours of unplanned outages, not including PSPS (normalized)

Item 3.d. Comments - The provided data for Item 3.d. was derived by taking the annual results noted as Item 3.c. and dividing by a corresponding/calculated annual number of RFW circuit mile day per year values as summarized in Table PG&E-2-2 above. As mentioned, the Table PG&E-2-2 values are based on the T&D overhead circuit miles.

- Item 3.e. Description** - Increase in System Average Interruption Duration Index (SAIDI)

Item 3.e. Comments - Since the overall "Metric type" noted for this metric is noted as, "Customer hours of PSPS and other outages, this group of questions was interpreted as asking for the SAIDI values based on all T&D unplanned and planned outages combined and including Major Event Days (MEDs). As such, PG&E's ILIS-ODB was used to show the annual SAIDI difference compared from each prior year from 2014 to 2019. In addition, the following should be noted:

- System reliability performance metrics typically exclude Major Events Days as defined per the IEEE Standard 1366, titled, "IEEE Guide for Electric Power Distribution Reliability Indices."
- PSPS events are typically large enough to meet the Major Event Day threshold as defined in the IEEE 1366 standard.

Comments for Table 2, Items 4a, 4b, 7-10f

The data in Table 2 is derived from ignitions that are linked to a wildfire, which is defined as a fire greater than 10 acres in size.

The statistics were normalized by dividing the 2015, 2016, 2017, 2018, and 2019 counts by the "RFW Circuit Mile Day Per Year" totals of 159,160; 175,945; 812,989; 850,940; 584,319, respectively, per Table PG&E-2-2, above.

- Items 4.a and 4.b** - PG&E is providing in the above table data for 2015 through 2019 for wildfires that CAL FIRE concluded were caused by PG&E equipment.
- Items 7.a. and 7.b.** - PG&E is providing in the above table data for all 2015-2019 wildfires that involve disputes regarding destroyed assets that have settled. These settlements are lump sum settlements that do not break out the settlement dollars by damage category. In addition, the settlements reached related to the 2017 North Bay Fires and the 2018 Camp Fire (other than the settlement with the cities and counties) do not break out the settlement dollars by fire. Any attempt to break out the dollars by fire and/or damage category would be speculative and inaccurate. The settlements are totaled based on the year of the fire. The one

exception is the 2018 Camp Fire which is reported with the 2017 North Bay Fires for the reasons described above. The chart does not include 2015-2019 wildfires that have not settled, which remain under investigation and/or civil discovery on causation issues, damages issues, or both.

~~• Items 8.a., 8.b., 9.a, and 9.b. PG&E is providing in the above table data for 2015 through 2019 for wildfires that CAL FIRE concluded were caused by PG&E equipment. The "structures damaged" metric represents the count of structures destroyed from incidents listed on CAL FIRE's website that can be linked to a fire ignition in PG&E's fire incident report.~~

~~Item 10 The 2015 through 2018 ignition data is primarily based on fire incident reports filed with the CPUC annually in accordance with D.14-02-015. These reports include fire incidents that may be associated with PG&E facilities and meet the following conditions: (1) a self-propagating fire of material other than electrical and/or communication facilities (2) the resulting fire traveled greater than one linear meter from the ignition point, and (3) PG&E has knowledge that the fire occurred. Where not already included as part of the CPUC fire incidents report data, PG&E also included data for 2015 through 2018 wildfires that CAL FIRE concluded were caused by PG&E equipment. As of the time of the 2020 WMP filing, 2019 ignition data is being reviewed by PG&E in preparation for its 2019 fire incident that will be submitted by April 1, 2020 per CPUC Decision D.14-02-015. The 2019 data in this table is preliminary and may be revised by the time that report is submitted.~~

• Items 8.a., 8.b., 9.a, 9.b., and 10 The 2015 through 2018 ignition data is primarily based on fire incident reports filed with the CPUC annually in accordance with D.14-02-015. These reports include fire incidents that may be associated with PG&E facilities and meet the following conditions: (1) a self-propagating fire of material other than electrical and/or communication facilities (2) the resulting fire traveled greater than one linear meter from the ignition point, and (3) PG&E has knowledge that the fire occurred. Where not already included as part of the CPUC fire incident report data, PG&E also included data for 2015 through 2018 wildfires that CAL FIRE concluded were caused by PG&E equipment and 2019 wildfires that CAL FIRE is currently investigating where the point of ignition may be located near PG&E overhead electric facilities. As of the time of the 2020 WMP filing, 2019 ignition data is being reviewed by PG&E in preparation for its 2019 fire incident report that will be submitted by April 1, 2020 per D.14-02-015. The 2019 data in this table is preliminary and may be revised by the time that report is submitted.

24 Description of Additional Metrics

Instructions for Table 3:

In addition to the metrics specified above, list and describe all other metrics the utility uses to evaluate wildfire mitigation performance, the utility's performance on those metrics over the last five years, the units reported, the assumptions that underlie the use of those metrics, and how the performance reported could be validated by third parties outside the utility, such as analysts or academic researchers. Identified metrics must be of enough detail and scope to effectively inform the performance (i.e., reduction in ignition probability or wildfire consequence) of each preventive strategy and program.

PG&E is providing a completed Table 3 below, followed by comments regarding specific information in Table 3.

Formatted: Font: Symbol

Formatted: Font: Symbol, 12 pt

Formatted: Indent Left: 0.33", Hanging: 0.25", Right: 0", No bullets or numbering, Tab stops: Not at 0.32" + 0.32"

TABLE 3: LIST AND DESCRIPTION OF ADDITIONAL METRICS, LAST 5 YEARS

Metric	Performance					Units	Underlying assumptions	Third-party validation
	2015	2016	2017	2018	2019			
Metric 1A - Number of Equipment Failure Caused Outages within the HFTD areas on RFW Days	14	13	199	109	71	Number of sustained and momentary outage events	See comments below.	See Note 1
Metric 1B - Total of Number of Equipment Failure Caused Outages within the HFTD areas on RFW Days (normalized)	0.00028	0.00018	0.00052	0.00025	0.00024	Sustained and momentary outage events per RFW Day-Mile / year	See comments below.	See Note 1
Metric 2A - Number of Vegetation Caused Outages within the HFTD areas on RFW Days	22	4	187	79	53	Number of sustained and momentary outage events	See comments below.	See Note 1
Metric 2B - Number of Vegetation Caused Outages within the HFTD areas on RFW Days (normalized)	0.00044	0.00006	0.00049	0.00018	0.00018	Sustained and momentary outage events per RFW Day-Mile / year	See comments below.	See Note 1
Metric 3A - Number of Other/Animal Caused Outages within the HFTD areas on RFW Days	69	19	715	702	106	Number of sustained and momentary outage events	See comments below.	See Note 1
Metric 3BA - Number of Other/Animal Caused Outages within the HFTD areas on RFW Days (normalized)	0.00139	0.00027	0.00187	0.00164	0.00036	Sustained and momentary outage events per RFW Day-Mile / year	See comments below.	See Note 1

TABLE 3: LIST AND DESCRIPTION OF ADDITIONAL METRICS, LAST 5 YEARS (CONTINUED)

Metric	Performance					Units	Underlying assumptions	Third-party validation
	2015	2016	2017	2018	2019			
Metric 4 – Number of non-exempt fuse devices in Tier 2 and 3 HFTD that operate due to faults	2,425	2,233	3,785	2,194	3,965	Number of sustained outages	See comments below.	See Note 1
Metric 5A - Number of T&D Wires Down Events within the HFTD areas that occur on RFW Days	D = 11 T = 0	D = 1 T = 0	D = 186 T = 4	D = 59 T = 2	D = 31 T = 2	Number of T&D Wire Down Events in HFTD on RFW Days	See comments below.	See Note 1
	11	1	190	61	33			
Metric 5B - Number of T&D Wires Down Events within the HFTD areas that occur on RFW Days (normalized)	0.000174	0.000011	0.000403	0.000117	0.000092	T&D Wire Down Events in HFTD areas per RFW Day-Mile / year	See comments below.	See Note 1

Note 1 – These metrics have not been validated by a third party and are only intended as general indicators to measure trends in performance and to help guide the WMP programs until a more formal measurement is agreed upon by the stakeholders. It should also be noted that in order to provide these metrics on the required timeframe, the data presented is based on simple data extractions without additional analysis to validate that the appropriate events are actually being included. Since the data extracted likely include events that should not be included (such as multiple instances of damage due to an actual fire event), the actual events should be thoroughly reviewed before normalizing the data or used for more than general indicators of trends.

Background Comments for Table 3 – Description of Additional Metrics

When normalizing the result by RFW Days, the measured events should also be those that occur during the hours of the RFW within the HFTD Tier 2 and Tier 3 areas, rather than normalizing for all events that occur within the entire service territory. In other words, events that may occur during rainy conditions or in the non-Tier 2 and Tier 3 areas should not be included. As discussed in the introduction to TABLE 2 above, it is may not be appropriate to normalize the "Near Hit" events noted in Table 2 Item 1.a. (that are based on all events within the entire service territory) with the calculated RFW Day - OH Circuit Miles (T&D Combined) values as shown in TABLE PG&E-2-2 (as shown in Table 2). Therefore, it is recommended that only the events that occur during the hours of the RFW within the Tier 2 and Tier 3 areas be normalized with those values in TABLE PG&E-2-2 and not those events that occur in the entire service territory. For convenience, TABLE PG&E-2-2 is repeated in this section.

TABLE PG&E-2-2: ANNUAL RFW DAYS - OH CIRCUIT MILES (T&D COMBINED)

RFW Day - OH Circuit Miles (T&D Combined)				
2015	2016	2017	2018	2019
63,304	89,832	471,375	522,855	360,281

PG&E utilizes the FIAs, which are noted in Figure 2 and align with the Tier 2 and Tier 3 HFTD areas. Although approximated, PG&E can assign all distribution level outage events by hour to an individual FIA and can quantify the circuit miles within each FIA during the hours of the RFW. Although PG&E cannot currently assign all transmission events to an FIA, it can estimate the circuit transmission miles in an FIA during a RFW. In addition, it has and will continue to identify the transmission wire down events involving the Tier 2 and Tier 3 HFTD areas.

For the distribution system, TABLE PG&E-2-3 shows the estimated RFW Day - OH Distribution Circuit Miles. The values in TABLE PG&E-2-3 were derived similarly as described for Table PG&E-2-2 with the exception that only the OH Distribution circuit line miles were used.

TABLE PG&E-2-3: ANNUAL RFW DAY - OH DISTRIBUTION CIRCUIT MILES

RFW Day - OH Distribution Circuit Miles				
2015	2016	2017	2018	2019
49,573	70,375	383,067	428,486	296,210.3

Due to the data limitations between PG&E's Transmission and Distribution systems, PG&E has proposed to use Table PG&E-2-2 to normalize T&D events that occur within the HFTD events during the hours of the RFW and Table PG&E-2-3 to normalize the Distribution events that occur within the HFTD events during the hours of the RFW. It should be noted this is an interim proposal and may change in the future since PG&E is also reviewing alternatives of using different methodologies to normalize the data, including using weather thresholds beyond the RFW criterion.

Planned Additional Metrics

In addition to the metrics already covered throughout this 2020 WMP, PG&E is also planning to use the following metrics to assess the various programs intended to reduce wildfire risk.

Distribution System Metrics

- Metric 1A - Number of Equipment Failure Caused Outages within the HFTD areas based on the events that occur in the corresponding FIAs during the hours of the RFW. This metric is intended to measure the effectiveness of asset repair, replacement and hardening work in reducing outages. This metric has been normalized by the values noted in TABLE PG&E-2-3.
- Metric 1B - Number of Equipment Failure Caused Outages within the HFTD areas based on the events that occur in the corresponding FIAs during the hours of the RFW and normalized by the values noted in TABLE PG&E-2-3.
- Metric 2A - Number of Vegetation Caused Outages within the HFTD areas based on the events that occur in the corresponding FIAs during the hours of the RFW. This metric will measure the effectiveness of vegetation work in reducing contact with energized facilities.
- Metric 2A - Number of Vegetation Caused Outages within the HFTD areas based on the events that occur in the corresponding FIAs during the hours of the RFW and normalized by the values noted in TABLE PG&E-2-3.
- Metric 3A - Number of Other/Animal Caused Outages within the HFTD areas based on the events that occur in the corresponding FIAs during the hours of the RFW. This metric will measure the effectiveness of animal abatement work and track the balance of outages that are not specifically related to Equipment Failure and Vegetation causes.

- Metric 3B - Number of Other/Animal Caused Outages within the HFTD areas based on the events that occur in the corresponding FIAs during the hours of the RFW and normalized by the values noted in TABLE PG&E-2-3.
- Metric 4 - Number of non-exempt fuse devices located in the Tier 2 and Tier 3 HFTD that operate faults and result in sustained outages with the expectation that this number will decline as future outage events are mitigated and the units are replaced. This topic is also discussed in the Table 11A section.

T&D Wire Down Metrics

- Metric 5A - Number of Wires Down Events within the HFTD areas based on the events that occur in the corresponding FIAs during the hours of the RFW. Although the distribution wire down events are basically a subset of the three outage cause categories above, this metric will separately measure the T&D wire down events, which represents a higher risk condition due to its potential proximity to the public. The chart in the excel files will include the totals only, not the individual T and D numbers.
- Metric 5B - Number of Wires Down Events within the HFTD areas based on the events that occur in the corresponding FIAs during the hours of the RFW but normalized by the values noted in TABLE PG&E-2-3.

Other Additional Metrics

PG&E has also enhanced the information collected regarding its Fire Incident Data Collection Plan as required under Decision 14-02-015 and has expanded the information collected in support of Item 20 of Decision 19-05-037. Most of the additional information is available starting in 2019 but a few fields will require process changes or a substitution of the original reporting requirement. In addition, if the Wildfire OII Corrective Actions multi-party settlement agreement is approved, PG&E will provide "near miss" information² on a quarterly basis to SED and other Settling Parties in accordance with Item 19 of the settlement.

² Documentation of "Near Hit" Potential Fire Incidents. PG&E will document "near hit" potential fire incidents, such as arcing or parking, that could have resulted in an ignition but did not, as well as fire ignitions that travelled one meter or less from the ignition point. This documentation will include the following categories of data: (1) Data from PG&E's Field Automation System ("FAS"), to the extent such data is collected in FAS as of the Effective Date, for events categorized with specific existing FAS codes to be agreed upon among PG&E, OSA, and SED. This data will include information related to "near hit" incidents from customer and service calls (inclusive of incidents detected by Smart meters), as well as "near hit" incidents data concerning secondary facilities and service drops; (2) All unplanned momentary and sustained outage data associated with PG&E's primary distribution facilities (inclusive of outages detected by Smart meters); (3) All unplanned outage data and path interruptions associated with PG&E's facilities operating at a transmission voltage level, whether or not customers were affected; and (4) Any fire ignitions that travelled one meter or less from an ignition point.

25 Description of Program Targets

Instructions for Table 4:

In addition to the metrics specified above, list and describe all program targets the electrical corporation uses to track utility WMP implementation, the utility's performance on those metrics over the last five years, the units reported, the assumptions that underlie the use of those metrics, and how the performance reported could be validated by third parties outside the utility, such as analysts or academic researchers. Identified metrics must be of enough detail and scope to effectively inform the performance (i.e., reduction in ignition probability or wildfire consequence) of each preventive strategy and program.

Each program target shall be associated with a percent completeness and based upon the contents of the WMP.

The 2019 WMP describes the enhanced, accelerated, and new programs that PG&E has implemented to mitigate and reduce the growing risk of wildfires faced by the communities it serves, in 2019 and beyond. There were 53 commitments made as part of the 2019 WMP; a comprehensive EOY performance has been provided to the CPUC. The below table contains a subset of the 53 commitments which have quantitative targets. The "third-party validation" column includes documents or records that support the commitment completion.

TABLE 4: LIST AND DESCRIPTION OF PROGRAM TARGETS, LAST 5 YEARS

Program target	2019 performance	Units	Underlying assumptions	Third-party validation
Complete WSIP enhanced inspection of all Transmission structures (49,715)	49,715 (100.0%)	structures	Aerial inspections (drone or helicopter) and either ground or climbing inspection of transmission towers and poles.	Inspections are documented in Pronto Forms.

TABLE 4: LIST AND DESCRIPTION OF PROGRAM TARGETS, LAST 5 YEARS (CONTINUED)

Program target	2019 performance	Units	Underlying assumptions	Third-party validation
Complete all high priority corrective actions (A and B tags) identified during Transmission inspections (5,839)	5,215 (89.3%)	tags	(1) Only high priority tags identified from WSIP enhanced inspections by 5/31 (2) Corrective actions are assumed complete when closed in SAP, meaning work was completed in the field and proper documentation has been verified and indicated as such in SAP (3) some of the "open" tags are on de-energized lines where there is no risk present and these tags will be repaired or resolved before the line would be returned to service.	Completion report generated from the SAP system
Complete WSIP enhanced inspection of all Distribution poles in the HFTD areas (694,250)	694,250 (100.0%)	poles	Perform enhanced ground inspections of all Tier 2 and Tier 3 HFTD poles, and some additional "buffer zone" poles	Inspections are documented using Pronto enhanced inspection forms
Complete all high priority corrective actions (A and B tags) identified during Distribution inspections (5,046)	4,881 (96.7%)	tags	(1) Only high priority tags identified from WSIP enhanced inspections by 5/31 (2) Corrective actions are assumed complete when closed in SAP, meaning work was completed in the field and proper documentation has been verified and indicated as such in SAP	Completion report generated from the SAP system.
Complete WSIP enhanced inspection of all substations (222)	222 (100.0%)	substations	Perform enhanced ground inspections of all Tier 2 and Tier 3 HFTD stations by May 1, 2019	Inspections are documented using Pronto enhanced inspection forms

TABLE 4: LIST AND DESCRIPTION OF PROGRAM TARGETS, LAST 5 YEARS (CONTINUED)

Program target	2019 performance	Units	Underlying assumptions	Third-party validation
Complete all high priority corrective actions (A and B tags) identified during Substation inspections. (746)	745 (100.0%) ³	tags	Complete priority A and priority B corrective notifications (tags) created by April 30, 2019.	Completion report generated from the SAP system.
System hardening in HFTD areas (150 miles)	171 (114.1%)	miles	1) Convert overhead circuit to underground where feasible 2) Retire/remove overhead assets where customers can be served by other means (distributed generation, micro-grid, etc.)	PG&E's Internal Audit reviewed and validated work completion results.
Perform enhanced vegetation management work in HFTD areas (2,450 circuit miles)	2,498 (102.0%)	miles	Reduce wildfire through (1) overhang clearing 4ft vertical from conductor to sky, for particular trees , (2) 12 ft radial clearing around the conductor, and (3) hazard tree mitigation.	PG&E's Internal Audit reviewed and validated work completion results.
Remove/work all dead or dying trees ("CEMA trees") identified by October 1 of the current year	48,374 (including 100% of CEMA trees identified before 10/1/19)	trees	100% of trees before 10/1 excludes trees where tree work where an approved exception was identified due to third party delays, including environmental permitting requirements, owner refusals, and agency approval or review.	Data tracked and downloaded from the Vegetation Management Database (VMD)

³ The one remaining B tag is an approved exception under the standard exception process as that repair is being bundled with additional notifications that need to be completed at the same substation and a single clearance has been scheduled to limit the impact on our system and customers

TABLE 4: LIST AND DESCRIPTION OF PROGRAM TARGETS, LAST 5 YEARS (CONTINUED)

Program target	2019 performance	Units	Underlying assumptions	Third-party validation
SCADA enable all remaining line reclosers in Tier 2 and Tier 3 HFTD areas (287)	287 (100.0%)	line reclosers	Install Supervisory Control and Data Acquisition (SCADA) functionality on all line reclosers which currently lack SCADA functionality and are operated manually.	CWSP Recloser Database
Operationalize resilience zone (1)	1 (100.0%)	resilience zone	(1) Installation of sectionalizing devices to enable isolation of the intended area from the rest of the distribution grid during PSPS (2) Installation of a pre-installed interconnection hub to enable the rapid connection of mobile generation during PSPS (3) Completion of any necessary hardening treatment(s) to enable safe energization of the intended area during PSPS weather conditions	Declaration document of Operational Readiness of the pilot resiliency zone with multiple functional leader's signoff.
Operate heavy-lift helicopters to aid in fire suppression and restoration efforts (4)	4 (100.0%)	helicopters	Operate 4 heavy-lift helicopters to respond to 100% of the agency (e.g., CAL-Fire) requests for PG&E to operate under agency's control to support in the 2019 fire season.	US Department of Transportation FAA Operating Certificate authorizing the operation of 4 heavy-lift helicopters.
Operationalize and install high-definition cameras (71)	133 (187.3%)	cameras	New installations of HD cameras that are used to identify, confirm and track wildfires.	The data from the operationalized PG&E HD Cameras is available at: http://www.alertwildfire.org
Install weather stations (400)	426 (106.5%)	weather stations	New physical installation of weather stations on a pole, tower or other asset in HFTD areas.	The data from the PG&E Weather Stations is available at: https://mesowest.utah.edu/cgi-bin/droman/stn_mnet.cgi?mnet=227

26 Detailed Information Supporting Outcome Metrics

Instructions for Table 5:

Enclose detailed information as requested for the metrics below. Report numbers of accidental deaths attributed to any utility wildfire mitigation activities, as listed in the utility's 2019 WMP filing or otherwise, according to the type of activity in column one, and by the relationship to the utility, for each of the last five years. For fatalities caused by activities beyond these categories, add rows to specify accordingly. The relationship to the utility statuses of full-time employee, contractor, and member of public are mutually exclusive, such that no individual can be counted in more than one category, nor can any individual fatality be attributed to more than one activity.

Report subtotals calculated for each row and column.

TABLE 5: ACCIDENTAL DEATHS DUE TO UTILITY WILDFIRE MITIGATION INITIATIVES, LAST 5 YEARS

Activity	Victim															Total
	Full-time employee					Contractor					Member of public ¹					
Year	2015	2016	2017	2018 ²	2019	2015	2016	2017	2018 ²	2019	2015	2016	2017	2018 ²	2019	
Wildfire Safety Inspection Program (WSIP) - Distribution	–	–	–	0	0	–	–	–	0	0	–	–	–	0	0	0
Wildfire Safety Inspection Program (WSIP) - Transmission	–	–	–	0	0	–	–	–	0	1	–	–	–	0	0	1
Vegetation management/fuel reduction	–	–	–	0	0	–	–	–	0	0	–	–	–	0	0	0
System Hardening	–	–	–	0	0	–	–	–	0	0	–	–	–	0	0	0
PSPS	–	–	–	0	0	–	–	–	0	0	–	–	–	0	0	0
Total	–	–	–	0	0	–	–	–		1	–	–	–	0	0	

Notes for Table 5:

1. Data for "Member of public" was derived from review of PG&E's "Riskmaster" database, which tracks third party claims.
2. PG&E's Community Wildfire Safety Program, under which PG&E tracks its wildfire mitigation activities, was developed in 2018, with the above activities implemented in late 2018. Therefore, the "Year 2018" data above represents data from late 2018.

Instructions for Table 6:

Report numbers of OSHA-reportable injuries attributed to any utility wildfire mitigation initiatives, as listed in the utility's 2019 WMP filing or otherwise, according to the type of activity in column one, and by the identity of the victim, for each of the last five years. For members of the public, all injuries that meet OSHA-reportable standards of severity (i.e., injury or illness resulting in loss of consciousness or requiring medical treatment beyond first aid) shall be included, even if those incidents are not reported to OSHA due to the identity of the victims.

For OSHA-reportable injuries caused by activities beyond these categories, add rows to specify accordingly. The victim identities listed are mutually exclusive, such that no individual victim can be counted as more than one identity, nor can any individual OSHA-reportable injury be attributed to more than one activity. Report subtotals calculated for each row and column.

PG&E is providing a completed Table 6 below, followed by comments regarding specific information in Table 6.

TABLE 6: OSHA-REPORTABLE INJURIES DUE TO UTILITY WILDFIRE MITIGATION INITIATIVES, LAST 5 YEARS

Activity	Victim															Total
	Full-time employee					Contractor ¹					Member of public ²					
Year	2015	2016	2017	2018 ³	2019	2015	2016	2017	2018 ³	2019	2015	2016	2017	2018 ³	2019	
Inspection-Distribution	–	–	–	0	0	–	–	–	0	13	–	–	–	0	0	13
Inspection-Transmission	–	–	–	0	0	–	–	–	0	12	–	–	–	0	0	12

TABLE 6: OSHA-REPORTABLE INJURIES DUE TO UTILITY WILDFIRE MITIGATION INITIATIVES, LAST 5 YEARS (CONTINUED)

Activity	Victim															Total
	Full-time employee					Contractor ¹					Member of public ²					
Year	2015	2016	2017	2018 ³	2019	2015	2016	2017	2018 ³	2019	2015	2016	2017	2018 ³	2019	
Enhanced Vegetation management/fuel reduction	–	–	–	0	0	–	–	–	N/A ¹	25	–	–	–	0	0	25
System Hardening	–	–	–	0	0	–	–	–	0	3	–	–	–	0	0	3
PSPS	–	–	–	0	0	–	–	–	0	0	–	–	–	0	0	0
Total	–	–	–	0	0	–	–	–	N/A	53	–	–	–	0	0	

Notes for Table 6:

1. PG&E does not generally and centrally track OSHA reportable incidents for contractors. Contractors are responsible for complying with OSHA reportable notification requirements. The data in Table 6 reflects all OSHA recordables, including any reportable incidents, that PG&E tracks for internal purposes.
2. Data for "Member of public" was derived from review of PG&E's "Riskmaster" database, which tracks third party claims.
3. PG&E's Community Wildfire Safety Program, under which PG&E tracks its wildfire mitigation activities, was developed in 2018, with the above activities implemented in late 2018. Therefore, the "Year 2018" data above represents data from late 2018.

Instructions for Table 7:

Report details on methodology used to calculate or model potential impact of ignitions, including list of all input used in impact simulation; data selection and treatment methodologies; assumptions, including Subject Matter Expert (SME) input; equation(s), functions, or other algorithms used to obtain output; output type(s), e.g., wind speed model; and comments.

PG&E is providing a completed Table 7 below, followed by comments regarding specific information in Table 7.

TABLE 7: METHODOLOGY FOR POTENTIAL IMPACT OF IGNITIONS

List of all data inputs used in impact simulation	Sources of data inputs	Data selection and treatment methodologies	Assumptions, including SME input	Equation(s), functions, or other algorithms used to obtain output	Output type(s), e.g., wind speed model	Comments
PG&E Ignitions 2015-2019 CALFIRE Incidents Fire weather warning data	PG&E CALFIRE National Weather Service	Model uses the S-MAP aligned bowtie framework. See details in Section 4.2 for treatment of data for the left and right side of the bowtie.	See details in Section 4.2	See Section 4.2 for details about Multi Attribute Value Function (MAVF) to combine all potential consequences of a risk event in a single value	Risk Score per Tranche (See Section 4.2 for modeled Consequences and Outcomes)	Inputs utilized in Wildfire Risk S-MAP conforming bowtie
Surface Fuels	LANDFIRE Remap 2016 (LF 2.0.0)	Data was extracted for these layers using the PG&E domain boundary with a buffer of 20 miles.	Fuel Models updated consistent with CPUC HFTD Map modification approach. "Sapsis, D., Brown, T., Low, C., Moritz, M., Saah, D., and Shaby,B., "Mapping Environmental Influences on Utility Fire Threat. A Report to the California Public Utilities Commission Pursuant to R.08 – 11-005 AND R.15-05-006." Final Report, 16 February 2016."	CalFire supported in 2016. Systematic errors identified in LANDFIRE led to use of alternative statewide vegetation data (CALVEG 2015) as a fuel system overlay onto LANDFIRE fuels for determination of mismatched fuel typing.	Modified LANDFIRE Fuels dataset	Details provided in Reax source report
Canopy Fuels	LANDFIRE Remap 2016 (LF 2.0.0)	Data was extracted for these layers using the PG&E domain boundary with a buffer of 20 miles.	See details in "Surface Fuels" above	CalFire supported in 2016. Systematic errors identified in LANDFIRE led to use of alternative statewide vegetation data (CALVEG 2015) as a fuel system overlay onto LANDFIRE fuels for determination of mismatched fuel typing.	Modified LANDFIRE Fuels dataset	Details provided in Reax source report

TABLE 7: METHODOLOGY FOR POTENTIAL IMPACT OF IGNITIONS (CONTINUED)

List of all data inputs used in impact simulation	Sources of data inputs	Data selection and treatment methodologies	Assumptions, including SME input	Equation(s), functions, or other algorithms used to obtain output	Output type(s), e.g., wind speed model	Comments
Terrain	USGS Geospatial Data Abstraction Library (GDAL)	USGS Geospatial Data Abstraction Library (GDAL) command line utilities were used to calculate slope, aspect, and terrain ruggedness rasters at 1/3 arcsecond resolution.	N/A	N/A	N/A	Approach utilized by Reax
Climatology	Numerical Weather Prediction (NWP)	NWP model Weather Research and Forecasting (WRF) was used to generate high-resolution wind and weather fields from ~200 historical fire weather days.	~200 historical fire weather days identified are acceptable proxy for fire spread modeling	N/A -Output is list of dates for each 32 km by 32 km NARR pixel in California where the most severe fire weather conditions occurred since 1979	List of dates to derive weather conditions for Monte Carlo simulations	Details provided in Reax source report
Fosberg Fire Weather Index (FFWI)	Weather fields from ~200 historical fire weather days	Fire weather index created to measure the potential influence of weather on a wildfire based on model output of temperature, wind and relative humidity.	~200 historical fire weather days identified are acceptable proxy for fire spread modeling	$FFWI = u \sqrt{1 + U^2}$	N/A	Details provided in Reax source report
Modified Fosberg Fire Weather Index (MFFWI)	Weather fields from ~200 historical fire weather days	MFFWI is used to identify wind events that occur simultaneously with low relative humidities and high temperatures	~200 historical fire weather days identified are acceptable proxy for fire spread modeling	$MFFWI = FFWI \times P_{ign}/100$	204 days corresponding to highest MFFWI in NARR dataset across California	Details provided in Reax source report

TABLE 7: METHODOLOGY FOR POTENTIAL IMPACT OF IGNITIONS (CONTINUED)

List of all data inputs used in impact simulation	Sources of data inputs	Data selection and treatment methodologies	Assumptions, including SME input	Equation(s), functions, or other algorithms used to obtain output	Output type(s), e.g., wind speed model	Comments
Buildings	Microsoft Building Data Source and 2010 US Census data for California were in GIS (shapefile) format	Housing density (structures/mi ²) was calculated for each of 710,145 census blocks in California by dividing the housing count for each census block by its area.	Census data is acceptable proxy for structure quantification	N/A	Housing density a raster having the same projection and resolution (30 m) as the underlying fuels inputs.	2010 Census tract data was utilized by Reax
Population	LandScan 2016 and 2010 US Census data for California were in GIS (shapefile) format	Population density (people/mi ²) density was calculated for each of 710,145 census blocks in California by dividing the population for each census block by its area.	Census data is acceptable proxy for quantification of population impacts	N/A	Population density a raster having the same projection and resolution (30 m) as the underlying fuels inputs.	2010 Census tract data was utilized by Reax
PG&E Assets	EDGIS and ET GIS	N/A	N/A	N/A	N/A	

TABLE 7: METHODOLOGY FOR POTENTIAL IMPACT OF IGNITIONS (CONTINUED)

List of all data inputs used in impact simulation	Sources of data inputs	Data selection and treatment methodologies	Assumptions, including SME input	Equation(s), functions, or other algorithms used to obtain output	Output type(s), e.g., wind speed model	Comments
Fire Escape Probability	Reax Engineering "Wildland Fire Risk Model for Establishing Fire Threat Zones:	Modeling assumed ignitions in 100 meter buffered area surrounding overhead electric transmission and distribution facilities within Fire Index Areas.	The ignition routines function by igniting a user-specified fraction (e.g., 50%) of the 30 m pixels contained within the rasterized ignition mask	$Pe \propto V_f \times (0.5 f(Pr) \times f(Ds) \times f(T))$	Five model outputs by percentile. Probability: Relative probability of fire escaping initial attack efforts	Pe - Probability of a fire escaping initial containment efforts V_f - Fire volume (acre-ft) after 6 hours of spread from

	Methodology and Results ^a				<div>Consequence homes: Impacted number of homes</div> <div>Consequence timber: Impacted acres of timber</div> <div>Risk homes: Overall risk to homes (probability times homes consequence)</div> <div>Risk timber: Overall risk to timber (probability times timber consequence)</div>	<div>Monte Carlo simulation</div> <div>θ-Calibration constant</div> <div>$f(x)$ Dimensionless function normalized between 0 and 1</div> <div>Pr - Road density (mi/mi2)</div> <div>Ds - Distance to closest fire station (mi)</div> <div>T - Topographical slope or ruggedness</div> <div>$f(Ds) = \min(ds/d's, 1)$</div> <div>$f(Pr) = \max(1 - Pr/P'r, 0)$</div> <div>$f(T) = \max(T - T'/90^\circ, 0)$</div>
--	--------------------------------------	--	--	--	---	--

Notes for Table 7:

PG&E currently utilizes two models to calculate the impact of potential ignitions. One model was developed to assess ignition based drivers and consequence outputs, conforming with the S-MAP settlement agreement. The second utilizes computational wildfire spread modeling developed by Reax Engineering to assist risk assessments on overhead electric facilities in PG&E's service territory. The data inputs listed in Table 7 represent the current set of data sets used by these models. The output of these models estimate acreage and/or volume of a potential fires spread based on assumption that ignitions occur.

For the S-MAP conforming model, potential outcomes are measured by the impacted structures and safety consequences. In the Reax model, risk and consequence outputs are quantified by the simulated fire volume and the impact to homes and/or timber resources through computational fire spread. Outputs are comparative by percentile.

A third model has been developed by Technosylva for PG&E in 2019.

2.7 Mapping Recent, Modelled, And Baseline Conditions

Instructions for Table 8:

Report underlying data for recent conditions (over the last five years) of the utility service territory in a downloadable shapefile GIS format, to include the following layers of data plotted on the utility service territory map as specified below, at a minimum. Provide information for each year; calculate and provide a five-year average. Name and attach files according to the table below.

TABLE 8: MAP FILE REQUIREMENTS FOR RECENT AND MODELLED CONDITIONS OF UTILITY SERVICE TERRITORY, LAST 5 YEARS

Layer name	Measurements	Units	Attachment location
Recent weather patterns	Average annual number of Red Flag Warning days per square mile across service territory	Area, days, square mile resolution	6.1
	Average 95 th and 99 th percentile wind speed and prevailing direction (actual)	Area, miles per hour, at a square mile resolution or better, noting where measurements are actual or interpolated	
Recent drivers of ignition probability	Date of recent ignitions categorized by ignition probability driver	Point, GPS coordinate, days, square mile resolution	6.2
Recent use of PSPS	Duration of PSPS events and area of the grid affected in customer hours per year	Area, customer hours, square mile resolution	6.3

Notes for Table 8:

- 1. Weather data is provided with 3 km resolution as a raster data set.

Instructions for Table 9:

Report underlying data for recent conditions (over the last five years) of the utility service territory in a downloadable shapefile GIS format, to include the following layers of data plotted on the utility service territory map as specified below, at a minimum. Provide information for each year; calculate and provide a five-year average. Name and attach files according to the table below.

TABLE 9: MAP FILE REQUIREMENTS FOR BASELINE CONDITION OF UTILITY SERVICE TERRITORY PROJECTED FOR 2020

Layer name	Measurements / variables	Units	Appendix location
Current baseline state of service territory and utility equipment	Non-HFTD vs HFTD (Zone 1, Tier 2, Tier 3) regions of utility service territory	Area, square mile resolution per type	6.4
	Urban vs. rural vs. highly rural regions of utility service territory	Area, square mile resolution per type	
	WUI regions of utility service territory	Area, square mile resolution	
	Number and location of critical facilities ¹	Point, GPS coordinate	
	Number and location of customers ²	Area, number of people, square mile resolution	
	Number and location of customers belonging to access and functional needs populations ²	Area, number of people, square mile resolution	
	Overhead transmission lines	Line, quarter mile resolution	
	Overhead distribution lines	Line, quarter mile resolution	
	Location of substations	Point, GPS coordinate	
	Location of weather stations	Point, GPS coordinate	
	All utility assets by asset type, model, age, specifications, and condition	Point, GPS coordinate	

**TABLE 9: MAP FILE REQUIREMENTS FOR BASELINE CONDITION OF UTILITY SERVICE TERRITORY PROJECTED FOR 2020
(CONTINUED)**

Layer name	Measurements / variables	Units	Appendix location
Location of planned utility equipment additions or removal	Non-HFTD vs HFTD (Zone 1, Tier 2, Tier 3) regions of utility service territory	Line, quarter mile resolution	6.5
	Urban vs. rural vs. highly rural regions of utility service territory	Line, quarter mile resolution	
	WUI regions of utility service territory	Line, quarter mile resolution	
	Circuit miles of overhead transmission lines	Line, quarter mile resolution	
	Circuit miles of overhead distribution lines	Line, quarter mile resolution	
	Location of substations	Point, GPS coordinate	
Planned 2020 WMP initiative activity per year	Location of 2020 WMP initiative activity for each activity as planned to be completed by the end of each year of the plan term	Line, quarter mile resolution	6.6

Notes for Table 9:

- All data provided in Appendices 6.4 through 6.6 in response to Table 9-1 is from PG&E's January 2020 EDGIS data base.
- The number of medical baseline customers is provided in lieu of the number of customers belonging to access and functional needs populations.
- PG&E is working to finalize GIS shapefiles identifying the number of customers, critical facilities, and medical baseline customers persquare mile. In the meantime, PG&E has provided Excel files which will enable a CA Grid Shapefile to be created for the number of customers per square mile; the number of critical facilities per square mile; and the number of medical baseline customers per square mile:
 - cpucGrid_CriticalCusts.xlsx
 - cpucGrid_AllCusts.xlsx
 - cpuc_Grid_medicalCusts.xlsx
- Customer locations and critical facilities locations, including the excel files identified above, are not included in the publicly posted data sets as this information is protected by customer personal data privacy requirements.

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION PLAN
SECTION 3
BASELINE IGNITION PROBABILITY AND
WILDFIRE RISK EXPOSURE

3 Baseline Ignition Probability and Wildfire Risk Exposure

3.1 Recent Weather Patterns, Last 5 Years

Instructions for Table 10:

Report weather measurements based upon the duration and scope of NWS Red Flag Warnings and upon proprietary Fire Potential Index (or other similar fire risk potential measure) for each year. Calculate and report 5-year historical average. Ensure underlying data is provided per Section 2.7.

Table 10 and other tables seek information regarding weather patterns over the last five years, including a 5-year historical average. PG&E has provided the requested data, but cautions against using the 5-year historical average to assess wildfire risks. California has experienced dramatic environmental changes in recent years, resulting in record drought, unprecedented tree mortality, record rainfall, record heat waves, and extremely strong wind events. These climate-related factors have contributed to the increasing risk of wildfires. Therefore PG&E views the trend in weather conditions to be more relevant to assessing wildfire risk than historical averages.

TABLE 10: WEATHER PATTERNS, LAST 5 YEARS

Weather measurement	2015	2016	2017	2018	2019	5-year historical average ^{a,b}	Unit(s)
Red Flag Warning days ^d	63,304	89,832	471,375	522,855	360,281	301,529	RFW circuit mile days per year
Days rated at the top 30% of proprietary fire potential index or similar fire risk index measure ^a	757,738	1,753,176	2,336,959	1,553,760	2,329,476	1,746,222	Circuit mile days where proprietary measure rated above top 30% threshold ¹ per year
95 th percentile wind conditions ^a	1,033,719	1,324,577	1,790,954	1,026,773	TBD ^a	1,294,006 ^c	Circuit mile days with wind gusts over 95 th percentile historical (meaning the prior 10 years, 2005-2014) conditions per year
99 th percentile wind conditions ^a	162,809	179,614	480,997	131,966	TBD ^a	238,847 ^c	Circuit mile days with wind gusts over 99 th percentile historical (meaning the prior 10 years, 2005-2014) conditions per year
Offshore (e.g., Diablo, Mono, Santa Ana) wind conditions ^a	14,830	2,867	96,643	106,652	TBD ^a	55,248 ^c	Circuit mile days that experience offshore (e.g., Diablo, Mono, Santa Ana) wind conditions (offshore wind events characterized as PG&E FPI >0.14 [filter for dry conditions], Wind Direction (N to ESE): 350°—112.5°, Sustained Wind Speeds ≥ 20 mph, Relative Humidity ≤ 25%, ≥3 consecutive hour duration, ≥0.5% areal coverage of conditions over model domain)

Notes for Table 10:

- A. Analysis is based on PG&E's 30-year weather and fuels climatology at 3 km spatial and hourly temporal resolution from 1989 – 2018. Data for 2019 in a similar format will not be available until late Q2 2020.
- B. 5-year historical average is based on PG&E's 30-year weather and fuels climatology at 3 km spatial and hourly temporal resolution from 1989 – 2018 and has been computed from 2014-2018.
- C. Average based on 2015 – 2018 data.
- D. Based on forecast data from the National Weather Service for HFTD areas as explained in the introduction to Section 2.2.

E. Based on PG&E FPI forecasts of R4 (very high) fire danger or greater

¹ Threshold here defined as top 30% of FPI or equivalent scale (e.g., "Extreme" on SCE's FPI; "extreme", 15 or greater, on SDG&E's FPI; and 4 or above on PG&E's FPI)

3.2 Recent Drivers of Ignition Probability, Last 5 Years

Instructions for Table 11:

Report recent drivers of ignition probability according to whether or not near misses of that type are tracked, the number of incidents per year (e.g., all instances of animal contact regardless of whether they caused an outage, an ignition, or neither), the rate at which those incidents (e.g., object contact, equipment failure, etc.) cause an ignition in the column, and the number of ignitions that those incidents caused by category, for each of last five years.

Calculate and include 5-year historical averages. This requirement applies to all utilities, not only those required to submit annual ignition data. Any utility that does not have complete 2019 ignition data compiled by the WMP deadline shall indicate in the 2019 columns that said information is incomplete. List additional drivers tracked in the "other" row and add additional rows as needed. Ensure underlying data is provided per Section 2.7.

Comments for Table 11: Key Recent Drivers of Ignition Probability, Last 5 Years

Table 11 (with data responses set forth in Tables 11-1, 11-2, 11-3, and 11-4) purports to seek "average percentage probability of ignition per incident," which are derived by dividing the number of ignitions per year by the total number of incidents per year. However, this calculation does not result in an average percentage probability, but a frequency. A frequency is the measure of how often an event occurs on average during a unit of time. In comparison, probability is a number between 0 and 1 that measures the chance some event may or may not happen. As a result, this calculation of number of ignitions per year divided by the total number of incidents per year indicates the number of ignitions per incidents. Moreover, it is inappropriate to average across historical years to derive future probability, because the fire threat conditions have changed over time as climate change has affected California. Instead of averaging these numbers, the numbers should be treated as a trend.

Since the categories vary between the Distribution and Transmission systems, a separate table is provided for each. In each case, unplanned outages are provided as the incidents. Table 11-1 covers the distribution system and Table 11-2 covers the transmission system. These summaries exclude all planned/wildfire mitigation outages and PSPS events since these events generally do not involve fault conditions.

In Table 11-1 and 11-2, PG&E has indicated that near misses are tracked by marking the respective column as Y. For the purpose of this exercise, PGE has taken the approach that an outage is a proxy for a near miss. Further, near misses in this context are only limited to outages.

Comments for Table 11-1: Distribution System

To the extent available, PG&E's ILIS-ODB data base was used to provide the level of detail as noted in Table 11-1 that includes both the sustained and momentary outages experienced on its distribution system. The following comments should be noted:

- The "All types" row noted in the "All types of Equipment/facility failure" group includes all outages related to equipment failure events. The additional sub categories listed below the "All types" category each represent a distinct subset of this overall total and provides a more detailed description of the failed equipment.
- Additional failed equipment line items (such as pole, insulator/bushing, crossarm, voltage regulator/booster, recloser, anchor/guy, and sectionalizer) were added to this table and will be discussed further relative to the ignition drivers.
- Similar to Table 11-2, the distribution wire down events related to the equipment failures include secondary related wire down events as contained within its ILIS-ODB.
- PG&E was unsure what was intended by use of the term "Fuse failure – all" since when a fuse isolates a fault condition, it will become permanently damaged and by design will no longer conduct electricity. For this subcategory, PG&E has interpreted it as only those outage events with a fuse reported as the actual failed equipment.
- In addition, it's unclear what was intended by the description of, "Fuse failure-conventional blown fuse". PG&E has interpreted this term as asking for information related to the operation of non-exempt fuses located in HFTD areas, which pose a potential fire risk since these fuses may release molten metal when isolating a fault. However, these fuses will operate due to all faults and is therefore not specifically reported as an equipment failure. As such, the operation of this equipment is discussed below, outside of the equipment failure section of Table 11-1.
- PG&E does not have an outage cause classification that specifically matches the term, "Wire-to-wire contact / Contamination" and has assumed that persistent conditions of these events would be reported as equipment failures. As such, PG&E has assumed this refers to outage causes reported due to unknown causes, which are typically related to temporary fault conditions with the cause not determined at the time of the outage event.
- The overall "Other" category represents all outages not reported as due to Vegetation, 3rd Party, Animal, Equipment Failure, or Unknown causes.

The 2015 through 2018 ignition data is based on fire incident reports filed with the CPUC annually in accordance with D.14-02-015. These reports include fire incidents that may be associated with PG&E facilities and meet the following conditions: (1) a self-propagating fire of material other than electrical and/or communication facilities (2) the resulting fire traveled greater than one linear meter from the ignition point, and (3) PG&E has knowledge that the fire occurred. At the time of this report, 2019 ignition data is being reviewed by PG&E in preparation for its 2019 fire incident report that will be submitted by April 1, 2020 per D.14-02-015. The data in this table is preliminary and may be revised by the time that report is submitted. The following comments should be noted regarding the ignition data:

- The note regarding the subcategories "Conductor failure— wires down" and "Wire-to-wire contact / contamination" for the outage data also applies to the ignition driver data. As a result, data is not input into these fields in Table 11.

- The note regarding the categories "Fuse failure – all" and the "Fuse failure-conventional blown fuse" for the outage data also applies to the ignition data.

Operation of Non-Exempt Fuses

PG&E estimates it has roughly over 15,000 non-exempt fuse devices located in the Tier 2 and Tier 3 HFTD areas. As mentioned above, the operation of these fuses pose a potential fire risk and PG&E has a plan to replace these units over the next several years. Listed below are the estimated number of times these devices operated/isolated faults each year, with an average of 2,920 outages/year.

TABLE PG&E-3-1: NON-EXEMPT FUSE DEVICES IN HFTD TIERS 2 AND 3

Year	2015	2016	2017	2018	2019	Average
Sustained Outages	2,425	2,233	3,785	2,194	3,965	2,920

PG&E plans to track the number of future operations in these devices as noted in the additional metric section shown in Table 3, Metric 4.

TABLE 11-1: KEY RECENT DRIVERS OF IGNITION PROBABILITY, LAST 5 YEARS – DISTRIBUTION SYSTEM

Incident type by ignition probability driver		Near misses tracked (y/n)?	Number of incidents per year						Average percentage probability of ignition per incident						Number of ignitions per year from this driver					
			2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average
Contact from object	All types of object contact	Y	9185.00	10029.00	13693.00	9171.00	13434.00	11102.40	2.46%	1.86%	1.86%	2.84%	1.88%	2.13%	226.00	187.00	255.00	260.00	253.00	236.20
	Animal contact	Y	2346.00	2242.00	2197.00	2447.00	2072.00	2260.80	1.66%	1.47%	2.09%	2.21%	3.19%	2.11%	39.00	33.00	46.00	54.00	66.00	47.60
	Balloon contact	Y	473.00	526.00	526.00	647.00	464.00	527.20	4.23%	2.47%	1.90%	2.47%	3.02%	2.77%	20.00	13.00	10.00	16.00	14.00	14.60
	Veg. contact	Y	3734.00	4432.00	8277.00	3285.00	8167.00	5579.00	2.65%	2.10%	1.57%	3.56%	1.44%	2.00%	99.00	93.00	130.00	117.00	118.00	111.40
	Vehicle contact	Y	1793.00	2041.00	1917.00	1915.00	1835.00	1900.20	2.62%	1.67%	2.76%	2.35%	2.02%	2.27%	47.00	34.00	53.00	45.00	37.00	43.20
	3 rd party Contact Other	Y	839.00	788.00	776.00	877.00	896.00	835.20	2.50%	1.78%	2.06%	3.19%	2.01%	2.32%	21.00	14.00	16.00	28.00	18.00	19.40
All types of equipment / facility failure	All types	Y	11099.00	11506.00	14700.00	10164.00	13031.00	12100.00	1.49%	1.23%	1.46%	1.28%	1.07%	1.31%	165.00	141.00	214.00	130.00	140.00	158.00
	Capacitor bank failure	Y	56.00	65.00	83.00	55.00	70.00	65.80	17.86%	16.92%	12.05%	18.18%	10.00%	14.59%	10.00	11.00	10.00	10.00	7.00	9.60
	Conductor failure—all	Y	2409.00	2661.00	3827.00	2395.00	3382.00	2934.80	3.57%	2.82%	2.69%	3.22%	2.25%	2.84%	86.00	75.00	103.00	77.00	76.00	83.40
	Conductor failure—wires down	Y	1134.00	1241.00	1996.00	1182.00	1593.00	1429.20	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

TABLE 11-1: KEY RECENT DRIVERS OF IGNITION PROBABILITY, LAST 5 YEARS – DISTRIBUTION SYSTEM (CONTINUED)

Incident type by ignition probability driver		Near misses tracked (y/n)?	Number of incidents per year						Average percentage probability of ignition per incident						Number of ignitions per year from this driver					
			2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average
	Fuse failure—all	Y	372.00	352.00	479.00	305.00	345.00	370.60	1.88%	1.14%	1.88%	3.28%	0.58%	1.73%	7.00	4.00	9.00	10.00	2.00	6.40
	Fuse failure—conventional blown fuse	Y	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Lightning arrestor failure	Y	144.00	145.00	139.00	135.00	130.00	138.60	4.17%	1.38%	4.32%	0.74%	3.08%	2.74%	6.00	2.00	6.00	1.00	4.00	3.80
	Switch failure	Y	136.00	156.00	178.00	187.00	189.00	169.20	2.21%	0.64%	1.69%	0.00%	2.12%	1.30%	3.00	1.00	3.00	0.00	4.00	2.20
	Trans-former failure	Y	4213.00	3947.00	4977.00	3136.00	3962.00	4047.00	0.36%	0.25%	0.42%	0.32%	0.53%	0.38%	15.00	10.00	21.00	10.00	21.00	15.40
	Pole	Y	498.00	628.00	1111.00	669.00	1162.00	813.60	1.20%	0.80%	1.17%	0.60%	0.34%	0.79%	6.00	5.00	13.00	4.00	4.00	6.40
	Insulator and bushing	Y	249.00	295.00	384.00	273.00	374.00	315.00	2.41%	1.02%	2.08%	1.83%	1.07%	1.65%	6.00	3.00	8.00	5.00	4.00	5.20
	Crossarm	Y	572.00	717.00	777.00	769.00	1001.00	767.20	0.52%	0.56%	1.42%	0.52%	0.20%	0.63%	3.00	4.00	11.00	4.00	2.00	4.80
	Voltage regulator/Booster	Y	59.00	62.00	60.00	52.00	59.00	58.40	1.69%	1.61%	5.00%	3.85%	5.08%	3.42%	1.00	1.00	3.00	2.00	3.00	2.00
	Recloser	Y	54.00	57.00	92.00	69.00	106.00	75.60	0.00%	5.26%	3.26%	0.00%	0.00%	1.59%	0.00	3.00	3.00	0.00	0.00	1.20

TABLE 11-1: KEY RECENT DRIVERS OF IGNITION PROBABILITY, LAST 5 YEARS – DISTRIBUTION SYSTEM (CONTINUED)

Incident type by ignition probability driver		Near misses tracked (y/n)?	Number of incidents per year						Average percentage probability of ignition per incident						Number of ignitions per year from this driver					
			2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average
	Anchor/Guy	Y	36.00	41.00	47.00	47.00	58.00	45.80	2.78%	2.44%	2.13%	0.00%	0.00%	1.31%	1.00	1.00	1.00	0.00	0.00	0.60
	Sectionalizer	Y	4.00	3.00	2.00	4.00	3.00	3.20	0.00%	33.33%	0.00%	0.00%	0.00%	6.25%	0.00	1.00	0.00	0.00	0.00	0.20
	Other Equipment	Y	2297.00	2377.00	2544.00	2068.00	2190.00	2295.20	0.91%	0.84%	0.90%	0.34%	0.59%	0.73%	21.00	20.00	23.00	7.00	13.00	16.80
Wire-to-wire contact / contamination (See notes section)		Y	14595.00	13424.00	18889.00	12002.00	16357.00	15053.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other		Y	2193.00	1285.00	2160.00	1785.00	1746.00	1833.80	1.46%	1.40%	0.60%	1.18%	2.23%	1.34%	32.00	18.00	13.00	21.00	39.00	24.60

TABLE 11-2: KEY RECENT DRIVERS OF IGNITION PROBABILITY, LAST 5 YEARS – TRANSMISSION SYSTEM

Incident type by ignition probability driver		Near misses tracked (y/n)?	Number of incidents per year						Average percentage probability of ignition per incident						Number of ignitions per year from this driver					
			2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average
Contact from object	All types of object contact	Y	155.00	136.00	232.00	138.00	150.00	162.20	3.87%	8.82%	4.31%	7.97%	8.67%	6.41%	6.00	12.00	10.00	11.00	13.00	10.40
	Animal	Y	41.00	43.00	43.00	49.00	32.00	41.60	14.63%	20.93%	11.63%	10.20%	18.75%	14.90%	6.00	9.00	5.00	5.00	6.00	6.20
	Vegetation	Y	50.00	41.00	122.00	26.00	64.00	60.60	0.00%	0.00%	0.00%	0.00%	1.56%	0.33%	0.00	0.00	0.00	0.00	1.00	0.20
	Mylar balloon	Y	9.00	5.00	12.00	14.00	9.00	9.80	0.00%	20.00%	8.33%	0.00%	0.00%	4.08%	0.00	1.00	1.00	0.00	0.00	0.40
	Car pole	Y	27.00	29.00	38.00	37.00	25.00	31.20	0.00%	3.45%	2.63%	8.11%	16.00%	5.77%	0.00	1.00	1.00	3.00	4.00	1.80
	3rd Party (foreign object /aircraft/ vandalism)	Y	28.00	18.00	17.00	12.00	20.00	19.00	0.00%	5.56%	17.65%	25.00%	10.00%	9.47%	0.00	1.00	3.00	3.00	2.00	1.80
Equipment / Facility Failure	All types of Equipment Failure	Y	97.00	122.00	145.00	123.00	132.00	123.80	3.09%	3.28%	5.52%	4.07%	6.06%	4.52%	3.00	4.00	8.00	5.00	8.00	5.60
	Arrestor	Y	0.00	1.00	1.00	0.00	0.00	0.40	N/A	0.00%	0.00%	N/A	N/A	0.00%	0.00	0.00	0.00	0.00	0.00	0.00
	Insulator or Bushing	Y	32.00	48.00	54.00	56.00	33.00	44.60	3.13%	0.00%	3.70%	1.79%	9.09%	3.14%	1.00	0.00	2.00	1.00	3.00	1.40
	Circuit breaker	Y	6.00	3.00	4.00	7.00	8.00	5.60	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00
	Conductor	Y	7.00	19.00	16.00	12.00	35.00	17.80	14.29%	15.79%	25.00%	8.33%	2.86%	11.24%	1.00	3.00	4.00	1.00	1.00	2.00

TABLE 11-2: KEY RECENT DRIVERS OF IGNITION PROBABILITY, LAST 5 YEARS – TRANSMISSION SYSTEM (CONTINUED)

Incident type by ignition probability driver		Near misses tracked (y/n)?	Number of incidents per year						Average percentage probability of ignition per incident						Number of ignitions per year from this driver					
			2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average
	Connector/ hardware	Y	11.00	21.00	19.00	10.00	13.00	14.80	0.00%	0.00%	0.00%	0.00%	7.69%	1.35%	0.00	0.00	0.00	0.00	1.00	0.20
	Other station	Y	21.00	17.00	18.00	14.00	20.00	18.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00
	Structure line	Y	7.00	7.00	27.00	20.00	18.00	15.80	0.00%	0.00%	3.70%	5.00%	0.00%	2.53%	0.00	0.00	1.00	1.00	0.00	0.40
	Switch (line+station)	Y	13.00	4.00	6.00	4.00	2.00	5.80	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00
	Transformer	Y	0.00	2.00	0.00	0.00	2.00	1.40	N/A	0.00%	N/A	N/A	20.00%	28.57%	1.00	0.00	0.00	0.00	1.00	0.40
	Other Equipment	N/A	0.00	0.00	0.00	0.00	0.00	0.00	N/A	N/A	N/A	N/A	N/A	N/A	0.00	1.00	1.00	2.00	2.00	1.20
Contamination	All types of contamination	Y	14.00	18.00	20.00	36.00	11.00	19.80	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00
Disaster	All Types of Disaster (all but 2 Fire)	Y	37.00	22.00	66.00	35.00	13.00	34.60	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00
Other	All types of Other (e.g., customer or IPP caused)	Y	17.00	5.00	11.00	19.00	24.00	15.20	23.53%	0.00%	54.55%	42.11%	25.00%	31.58%	4.00	0.00	6.00	8.00	6.00	4.80
Unknown	Patrol Found No Cause, No Damage	Y	125.00	139.00	156.00	160.00	138.00	143.60	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00

Deleted: 5

TABLE 11-2: KEY RECENT DRIVERS OF IGNITION PROBABILITY, LAST 5 YEARS – TRANSMISSION SYSTEM (CONTINUED)

Incident type by ignition probability driver		Near misses tracked (y/n)?	Number of incidents per year						Average percentage probability of ignition per incident						Number of ignitions per year from this driver					
			2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average	2015	2016	2017	2018	2019	Average
Weather	All types of Weather	Y	278.00	84.00	202.00	38.00	204.00	161.20	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00
	Lightning	Y	226.00	58.00	72.00	30.00	109.00	99.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00
	Rain	Y	5.00	12.00	47.00	0.00	23.00	17.40	0.00%	0.00%	0.00%	N/A	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00
	Snow/ Ice	Y	7.00	1.00	38.00	8.00	61.00	23.00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00
	Wind	Y	40.00	13.00	45.00	0.00	11.00	21.80	0.00%	0.00%	0.00%	N/A	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00
Work Procedure Error (WPE)	All types of WPE	Y	20.00	16.00	18.00	26.00	21.00	20.20	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00	0.00	0.00

3.3 Recent Use of PSPS, Last 5 Years

Instructions for Table 12:

Report use of PSPS according to the number and duration of PSPS events in total and normalized across weather conditions each year (by dividing by the number of RFW circuit mile days). List additional PSPS characteristics tracked in the "other" row and additional rows as needed.

TABLE 12: RECENT USE OF PSPS, LAST 5 YEARS

PSPS characteristic	2015	2016	2017	2018	2019	Unit(s)
Frequency of PSPS events (total)	N/A	N/A	N/A	1	9	Number of instances where utility operating protocol requires de-energization of a circuit or portion thereof to reduce ignition probability, per year
Frequency of PSPS events (normalized)	N/A	N/A	N/A	0.000019	0.000025	Number of instances where utility operating protocol requires de-energization of a circuit or portion thereof in order to reduce ignition probability, per RFW circuit mile day per year
Scope of PSPS events (total)	N/A	N/A	N/A	41	16,506	Circuit-events, measured in number of events multiplied by number of circuits de-energized per year
Scope of PSPS events (normalized)	N/A	N/A	N/A	0.000078	0.046	Circuit-events, measured in number of events multiplied by number of circuits targeted for de-energization per RFW circuit mile day per year
Duration of PSPS events (total)	N/A	N/A	N/A	1,517,371	98,617,112	Customer hours per year
Duration of PSPS events (normalized)	N/A	N/A	N/A	3	274	Customer hours per RFW circuit mile day per year
RFW circuit mile day per year	63,304	89,832	471,375	522,855	360,281	Aligns with CPUC WSD provided definition: "Sum of miles of utility grid subject to Red Flag Warning each day, with day being defined as a 24 hour period."

3.4 Baseline State of Equipment and Wildfire and PSPS Event Risk Reduction Plans

3.4.1 Current Baseline State of Service Territory and Utility Equipment

Instructions for Table 13:

Provide summary data for the current baseline state of HFTD and non-HFTD service territory in terms of circuit miles; overhead transmission lines, overhead distribution lines, substations, and critical facilities located within the territory; and customers by type, located in urban versus rural versus highly rural areas and including the subset within the Wildland-Urban Interface (WUI).

The totals of the cells for each category of information (e.g., "circuit miles" or "circuit miles in WUI") would be equal to the overall service territory total (e.g., the total of number of customers in urban, rural, and highly rural areas of HFTD plus those in urban, rural, and highly rural areas of non-HFTD would equal the total number of customers of the entire service territory). Ensure underlying data is provided per Section 2.7.

Table 13 seeks information regarding the current baseline state of HFTD and non-HFTD service territory, as located in urban versus rural versus highly rural areas, including a subset with the Wildland-Urban Interface (WUI). The WUI is defined as areas where homes are built near or among lands prone to wildland fires. PG&E identifies WUI areas within PG&E's service territory based upon data provided by the University of Wisconsin-Madison SILVIS Lab. Figure PG&E-3-1, which downloaded from an [Esri feature service](http://silvis.forest.wisc.edu/data/wui-change/) created by SILVIS Labs of University of Wisconsin, available here: <http://silvis.forest.wisc.edu/data/wui-change/>, shows the WUI areas within California as of 2010.

FIGURE PG&E 3-1: WUI AREAS WITHIN CALIFORNIA (2010)



TABLE 13: CURRENT BASELINE STATE OF SERVICE TERRITORY AND UTILITY EQUIPMENT

Land use	Characteristic tracked	In non-HFTD	In HFTD Zone 1	In HFTD Tier 2	In HFTD Tier 3
In urban areas	Circuit miles	15,604	9	996	395
	Circuit miles in WUI	4,195	8	721	340
	Number of critical facilities	15,547	3	498	172
	Number of critical facilities in WUI	3,807	2	345	145
	Number of customers	3,808,019	2,076	74,494	28,590
	Number of customers in WUI	1,131,021	1,810	65,428	26,600
	Number of customers belonging to access and functional needs populations	118,991	45	2,091	727
	Number of customers belonging to access and functional needs populations in WUI	37,894	39	1,909	690
	Circuit miles of overhead transmission lines	2,048	0	208	53
	Circuit miles of overhead transmission lines in WUI	64	0	82	36
	Circuit miles of overhead distribution lines	13,556	9	789	341
	Circuit miles of overhead distribution lines in WUI	4,130	8	638	304
	Number of substations	314	0	18	0
	Number of substations in WUI	94	0	14	0

TABLE 13: CURRENT BASELINE STATE OF SERVICE TERRITORY AND UTILITY EQUIPMENT (CONTINUED)

Land use	Characteristic tracked	In non-HFTD	In HFTD Zone 1	In HFTD Tier 2	In HFTD Tier 3
In rural areas	Circuit miles	45,119	87	17,020	7,229
	Circuit miles in WUI	7,962	57	9,479	4,671
	Number of critical facilities	9,685	42	1,748	972
	Number of critical facilities in WUI	2,392	29	1,089	664
	Number of customers	962,774	3,608	237,748	124,077
	Number of customers in WUI	459,138	3,238	202,687	112,491
	Number of customers belonging to access and functional needs populations	36,172	150	11,082	5,466
	Number of customers belonging to access and functional needs populations in WUI	18,505	144	10,038	5,165
	Circuit miles of overhead transmission lines	8,866	13	2,872	1,071
	Circuit miles of overhead transmission lines in WUI	915	6	815	286
	Circuit miles of overhead distribution lines	36,253	74	14,149	6,158
	Circuit miles of overhead distribution lines in WUI	7,047	51	8,664	4,386
	Number of substations	289	0	35	7
	Number of substations in WUI	67	0	27	18

TABLE 13: CURRENT BASELINE STATE OF SERVICE TERRITORY AND UTILITY EQUIPMENT (CONTINUED)

Land use	Characteristic tracked	In non-HFTD	In HFTD Zone 1	In HFTD Tier 2	In HFTD Tier 3
In highly rural areas	Circuit miles	7,302	39	4,539	825
	Circuit miles in WUI	563	9	1,035	331
	Number of critical facilities	641	7	295	102
	Number of critical facilities in WUI	106	3	120	52
	Number of customers	34,715	1,219	31,260	9,420
	Number of customers in WUI	13,620	989	20,995	7,584
	Number of customers belonging to access and functional needs populations	835	8	1,094	229
	Number of customers belonging to access and functional needs populations in WUI	472	4	801	185
	Circuit miles of overhead transmission lines	1,704	12	1,144	169
	Circuit miles of overhead transmission lines in WUI	50	0	102	31
	Circuit miles of overhead distribution lines	5,598	27	3,395	656
	Circuit miles of overhead distribution lines in WUI	513	9	933	300
	Number of substations	51	0	22	6
	Number of substations in WUI	3	0	7	3

Notes for Table 13:

- The WUI data were downloaded from an [Esri feature service](#) created by SILVIS Labs of University of Wisconsin. Metadata for the layer are available [here](#).
- The population density layer was derived by 'dissolving' US Census Tract population density data by the criteria defined by the CPUC:
 - Urban: Greater than or Equal to 1000 persons per square mile

- Rural: Less than 1000 persons per square mile but Greater than 7 persons per square mile
 - Highly rural: Less than or equal to 7 persons per square mile.
3. Circuit miles = Circuit miles of overhead transmission lines + Circuit miles of overhead distribution lines
 4. Circuit miles in WUI = Circuit miles of overhead transmission lines in WUI + Circuit miles of overhead distribution lines in WUI
 5. Critical facility data was sourced using customer billing data by intersecting the result with both the population density layer as well as the WUI layer.
 6. Existing ETGIS and EDGIS data (overhead lines, substations) were intersected with the population density layer and the WUI layer, respectively.

Instructions for Table 14:

Input summary data on number of utility weather stations located in utility service territory by type.

TABLE 14: SUMMARY DATA ON WEATHER STATION COUNT

Weather station count type	Current count	Unit(s)
Number of weather stations (total)	630	Total number located in service territory and operated by utility
Number of weather stations (normalized)	0.0063	Total number located in service territory and operated by utility, divided by total number of circuit miles in utility service territory
Number of weather stations in non-HFTD (total)	75	Total number located in non-HFTD service territory and operated by utility
Number of weather stations in non-HFTD (normalized)	0.0011	Total number located in non-HFTD service territory and operated by utility, divided by total number of circuit miles in non-HFTD service territory
Number of weather stations in HFTD Zone 1 (total)	0	Total number located in HFTD Zone 1 service territory and operated by utility
Number of weather stations in HFTD Zone 1 (normalized)	NA	Total number located in HFTD Zone 1 service territory and operated by utility, divided by total number of circuit miles in HFTD Zone 1 service territory
Number of weather stations in HFTD Tier 2 (total)	372	Total number located in HFTD Tier 2 service territory and operated by utility
Number of weather stations in HFTD Tier 2 (normalized)	0.0165	Total number located in HFTD Tier 2 service territory and operated by utility, divided by total number of circuit miles in HFTD Tier 2 service territory
Number of weather stations in HFTD Tier 3 (total)	183	Total number located in HFTD Tier 3 service territory and operated by utility
Number of weather stations in HFTD Tier 3 (normalized)	0.0217	Total number located in HFTD Tier 3 service territory and operated by utility, divided by total number of circuit miles in HFTD Tier 3 service territory

Notes for Table 14:

- 1. PG&E currently employs one mobile weather station which is not reflected in the above table.

Instructions for Table 15:

Input summary data on number of utility fault indicators located in utility service territory by type.

TABLE 15: SUMMARY DATA ON FAULT INDICATOR COUNT

Fault indicator count type	Distributio n Current count	Transmission Current count	Unit(s)
Number of fault indicators (total)	19,651	63	Total number located in service territory and operated by utility
Number of fault indicators (normalized)	0.2438	.0035	Total number located in service territory and operated by utility, divided by total number of circuit miles in utility service territory
Number of fault indicators in non-HFTD (total)	15,293	28	Total number located in non-HFTD service territory and operated by utility
Number of fault indicators in non-HFTD (normalized)	0.2781	0.0035	Total number located in non-HFTD service territory and operated by utility, divided by total number of circuit miles in non-HFTD service territory
Number of fault indicators in HFTD Zone 1 (total)	46	0	Total number located in HFTD Zone 1 service territory and operated by utility
Number of fault indicators in HFTD Zone 1 (normalized)	0.4182	0	Total number located in HFTD Zone 1 service territory and operated by utility, divided by total number of circuit miles in HFTD Zone 1 service territory
Number of fault indicators in HFTD Tier 2 (total)	2,978	28	Total number located in HFTD Tier 2 service territory and operated by utility
Number of fault indicators in HFTD Tier 2 (normalized)	0.1624	0.0064	Total number located in HFTD Tier 2 service territory and operated by utility, divided by total number of circuit miles in HFTD Tier 2 service territory

TABLE 15: SUMMARY DATA ON FAULT INDICATOR COUNT (CONTINUED)

Fault indicator count type	Distribution Current count	Transmission Current count	Unit(s)
Number of fault indicators in HFTD Tier 3 (total)	1,334	7	Total number located in HFTD Tier 3 service territory and operated by utility
Number of fault indicators in HFTD Tier 3 (normalized)	0.1864	0.0053	Total number located in HFTD Tier 3 service territory and operated by utility, divided by total number of circuit miles in HFTD Tier 3 service territory

3.4.2 Planned Additions, Removal, and Upgrade of Utility Equipment by End of 3-Year Plan Term

Instructions for Table 16:

Input summary information for the planned additions or removal of utility equipment to be completed by the end of the 3-year plan term in 2022. Report net additions using positive numbers and net removals and undergrounding using negative numbers for circuit miles and numbers of substations.

For transmission and distribution overhead line additions and removals for 2021 and 2022, project prioritization and timing have yet to be fully determined or mapped. Table 16 represents all fully developed and mappable work for 2020-2022.

TABLE 16: LOCATION OF PLANNED UTILITY EQUIPMENT ADDITIONS OR REMOVAL BY END OF 3-YEAR PLAN TERM

Land use	Characteristic tracked	Changes by end-2022			
		In non-HFTD	In HFTD Zone 1	In HFTD Tier 2	In HFTD Tier 3
In urban areas	Circuit miles of overhead transmission lines	0	0	0	0
	Circuit miles of overhead distribution lines	-9.27	0.00	-0.76	-0.15
	Circuit miles of overhead transmission lines in WUI	0	0	0	0
	Circuit miles of overhead distribution lines in WUI	-0.78	0.00	-0.45	-0.11
	Number of substations	0	0	0	0
	Number of substations in WUI	0	0	0	0
	Number of weather stations	N/A	N/A	N/A	N/A
	Number of weather stations in WUI	N/A	N/A	N/A	N/A

TABLE 16: LOCATION OF PLANNED UTILITY EQUIPMENT ADDITIONS OR REMOVAL BY END OF 3-YEAR PLAN TERM (CONTINUED)

Land use	Characteristic tracked	Changes by end-2022			
		In non-HFTD	In HFTD Zone 1	In HFTD Tier 2	In HFTD Tier 3
In rural areas	Circuit miles of overhead transmission lines	-0.47	0	-2.09	-1.48
	Circuit miles of overhead distribution lines	-77.10	-0.19	-13.18	-5.15
	Circuit miles of overhead transmission lines in WUI			-0.38	-0.21
	Circuit miles of overhead distribution lines in WUI	-9.06	-0.19	-8.76	-4.50
	Number of substations	0	0	0	0
	Number of substations in WUI	0	0	0	0
	Number of weather stations	N/A	N/A	N/A	N/A
	Number of weather stations in WUI	N/A	N/A	N/A	N/A
In highly rural areas	Circuit miles of overhead transmission lines	0	0	0	0
	Circuit miles of overhead distribution lines	-12.69	0.00	-4.17	-0.47
	Circuit miles of overhead transmission lines in WUI	0	0	0	0
	Circuit miles of overhead distribution lines in WUI	-0.95	0.00	-1.70	-0.14
	Number of substations	-1	0	0	0
	Number of substations in WUI	0	0	0	0
	Number of weather stations	N/A	N/A	N/A	N/A
	Number of weather stations in WUI	N/A	N/A	N/A	N/A

Transmission lines refer to all lines 60 kV and above, and distribution lines refer to all lines below 60 kV.

Instructions for Table 17:

Referring to the program targets discussed above, report plan for hardening upgrades in detail below. Report plan in terms of number of circuit miles or substations to be upgraded for each year, assuming complete implementation of wildfire mitigation activities, for HFTD and non-HFTD service territory for circuit miles of transmission lines, circuit miles of transmission lines located in Wildland-Urban Interface (WUI), circuit miles of distribution lines, circuit miles of distribution lines in WUI, number of substations, and number of substations in the WUI.

Include a list of the hardening initiatives included in the calculations for the below table.

This table identifies miles related to PG&E's distribution system hardening and Butte Rebuild programs as described in the program targets. PG&E has not established dedicated transmission line or substation wildfire hardening programs and has marked the table with N/A for those cells.

Of the 241 miles forecasted for 2020, 183.1 total miles of distribution system hardening projects have been fully mapped to enable sorting into characteristics requested for this table. While PG&E has determined program targets for 2021 and 2022, project prioritization and timing have yet to be fully determined or mapped. Thus, cells for 2021 and 2022 have been marked as To Be Determined (TBD).

TABLE 17: LOCATION OF PLANNED UTILITY INFRASTRUCTURE UPGRADES (CONTINUED)

Land use	Characteristic tracked	In non-HFTD			In HFTD Zone 1			In HFTD Tier 2			In HFTD Tier 3		
		2020	2021	2022	2020	2021	2022	2020	2021	2022	2020	2021	2022
	Number of substations in WUI to harden	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
In highly rural areas	Circuit miles of overhead transmission lines to harden	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Circuit miles of overhead transmission lines in WUI to harden	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Circuit miles of overhead distribution lines to harden	0	TBD	TBD	0	TBD	TBD	0	TBD	TBD	0	TBD	TBD
	Circuit miles of overhead distribution lines in WUI to harden	0	TBD	TBD	0	TBD	TBD	0	TBD	TBD	0	TBD	TBD
	Circuit miles of overhead transmission lines in WUI to harden	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Number of substations to harden	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Number of substations in WUI to harden	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Transmission lines refer to all lines at or above 60kV, and distribution lines refer to all lines below 60kV.

3.4.3 Status Quo Ignition Probability Drivers by Service Territory

Instructions for Table 18:

Report 5-year historical average drivers of ignition probability according to:

- the average number of incidents per year
- the likelihood of ignition per incident, meaning, the rate at which those incidents (e.g., object contact, equipment failure, etc.) would be expected to cause an ignition (e.g., if 50% of vegetation contacts result in ignition, then the value for the "Likelihood of ignitionper incident" column would be "50%"in that row); and
- the 5-year historical average of the number of ignitions from this driver by location in non-HFTD, HFTD Zone 1, HFTD Tier 2, and HFTD Tier 3. List additional risk drivers tracked in the "other" row and additional rows as needed. If changes would be expected for plan years 2 and 3,describe.

Comments for Table 18

Similar to Table 11, Table 18 purports to seek "ignition probability drivers," which are derived by dividing the number of ignitions per year by the total number of incidents per year. However, as explained in the introduction to Table 11, this calculation does not result in an average percentage probability, but a frequency. A frequency is the measure of how often an event occurs on average during a unit of time. In comparison, probability is a number between 0 and 1 that measures the chance some event may or may not happen. As a result, this calculation of number of ignitions per year divided by the total number of incidents per year indicates the number of ignitions per incidents. Moreover, it is inappropriate to average across historical years to derive future probability, because the fire threat conditions have changed over time as climate change has affected California. Instead of averaging these numbers, the numbers should be treated as a trend.

Likewise, as with Table 11, the categories vary between the Distribution and Transmission systems and a separate table is provided for each. In each case, unplanned outages are provided as the incidents. Table 18-1 covers the distribution system and Table 18-2 covers the transmission system. These summaries exclude all planned/wildfire mitigation outages and Public Power Shut-off events since these events generally do not involve fault conditions.

TABLE 18-1: KEY DRIVERS OF IGNITION PROBABILITY – DISTRIBUTION

Ignition probability drivers		Number of incidents per year (according to 5-year historical average)	Average likelihood of ignition per incident	Ignitions from this driver (according to 5-year historical average)				
				Total	In non-HFTD	In HFTD Zone 1	In HFTD Tier 2	In HFTD Tier 3
Contact from object	All types of object contact	11,102.40	2.13%	236.20	146.00	0.40	61.80	28.00
	Animal contact	2,260.80	2.11%	47.60	37.80	0.00	8.00	1.80
	Balloon contact	527.20	2.77%	14.60	12.80	0.00	1.80	0.00
	Vegetation contact	5,579.00	2.00%	111.40	50.60	0.40	39.00	21.40
	Vehicle contact	1,900.20	2.27%	43.20	31.40	0.00	9.80	2.00
	Contact from Object - Other	835.20	2.32%	19.40	13.40	0.00	3.20	2.80
All types of equipment / facility failure	All types	12,100.00	1.31%	158.00	125.00	0.40	24.60	8.00
	Capacitor bank failure	65.80	14.59%	9.60	8.20	0.00	0.80	0.60
	Conductor failure—all	2,934.80	2.84%	83.40	64.80	0.20	13.60	4.80
	Conductor failure—wires down	1,429.20	N/A	N/A	N/A	N/A	N/A	N/A
	Fuse failure—all	370.60	1.73%	6.40	4.80	0.00	1.40	0.20
	Fuse failure—conventional blown fuse	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Lightning arrestor failure	138.60	2.74%	3.80	3.60	0.00	0.20	0.00
	Switch failure	169.20	1.30%	2.20	1.80	0.00	0.40	0.00
	Transformer failure	4,047.00	0.38%	15.40	12.60	0.20	2.20	0.40

TABLE 18-1: KEY DRIVERS OF IGNITION PROBABILITY – DISTRIBUTION (CONTINUED)

Ignition probability drivers		Number of incidents per year (according to 5-year historical average)	Average likelihood of ignition per incident	Ignitions from this driver (according to 5-year historical average)				
				Total	In non-HFTD	In HFTD Zone 1	In HFTD Tier 2	In HFTD Tier 3
	Pole	813.60	0.79%	6.40	5.40	0.00	0.80	0.20
	Insulator and bushing	315.00	1.65%	5.20	4.40	0.00	0.60	0.20
	Crossarm	767.20	0.63%	4.80	3.60	0.00	0.80	0.40
	Voltage regulator/ Booster	58.40	3.42%	2.00	1.40	0.00	0.60	0.00
	Recloser	75.60	1.59%	1.20	1.20	0.00	0.00	0.00
	Anchor/Guy	45.80	1.31%	0.60	0.40	0.00	0.20	0.00
	Sectionalizer	3.20	6.25%	0.20	0.20	0.00	0.00	0.00
	Other Equipment	2,295.20	0.73%	16.80	12.60	0.00	3.00	1.20
Wire-to-wire contact / contamination		15,053.40	N/A	N/A	N/A	N/A	N/A	N/A
Other		1,833.80	1.34%	24.60	19.20	0.00	3.40	2.00

TABLE 18-2: KEY DRIVERS OF IGNITION PROBABILITY – TRANSMISSION

Ignition probability drivers		Number of incidents per year (according to 5-year historical average)	Average likelihood of ignition per incident	Ignitions from this driver (according to 5-year historical average)				
				Total	In non-HFTD	In HFTD Zone 1	In HFTD Tier 2	In HFTD Tier 3
Contact from object	All types of object contact	162.20	6.41%	10.40	5.40	0.00	3.60	1.40
	Animal	41.60	14.90%	6.20	2.80	0.00	2.80	0.60
	Vegetation	60.60	0.33%	0.20	0.00	0.00	0.20	0.00
	Mylar balloon	9.80	4.08%	0.40	0.20	0.00	0.00	0.20
	Car pole	31.20	5.77%	1.80	1.80	0.00	0.00	0.00
	3rd Party (foreign object/ aircraft/ vandalism)	19.00	9.47%	1.80	0.60	0.00	0.60	0.60
Equipment / Facility Failure	All types of Equipment Failure	123.80	4.52%	5.60	2.80	0.00	2.20	0.60
	Arrestor	0.40	0.00%	0.00	0.00	0.00	0.00	0.00
	Insulator or Bushing	44.60	3.14%	1.40	0.80	0.00	0.60	0.00
	Circuit breaker	5.60	0.00%	0.00	0.00	0.00	0.00	0.00
	Conductor	17.80	11.24%	2.00	0.80	0.00	1.20	0.00
	Connector/ hardware	14.80	1.35%	0.20	0.20	0.00	0.00	0.00
	Other station	18.00	0.00%	0.00	0.00	0.00	0.00	0.00
	Structure line	15.80	2.53%	0.40	0.40	0.00	0.00	0.00
	Switch (line+station)	5.80	0.00%	0.00	0.00	0.00	0.00	0.00

TABLE 18-2: KEY DRIVERS OF IGNITION PROBABILITY – TRANSMISSION (CONTINUED)

Ignition probability drivers		Number of incidents per year (according to 5-year historical average)	Average likelihood of ignition per incident	Ignitions from this driver (according to 5-year historical average)				
				Total	In non-HFTD	In HFTD Zone 1	In HFTD Tier 2	In HFTD Tier 3
Contamination	Transformer	1.40	28.57%	0.40	0.20	0.00	0.20	0.00
	Other Equipment	0.00	N/A	1.20	0.40	0.00	0.20	0.60
	All types of contamination	19.80	0.00%	0.00	0.00	0.00	0.00	0.00
Disaster	All Types of Disaster (all but 2 Fire)	34.60	0.00%	0.00	0.00	0.00	0.00	0.00
Other	All types of Other (e.g., customer or IPP caused)	15.20	31.58%	4.80	3.80	0.00	0.80	0.20
Unknown	Patrol Found No Cause, No Damage	143.60	0.00%	0.00	0.00	0.00	0.00	0.00
Weather	All types of Weather	161.20	0.00%	0.00	0.00	0.00	0.00	0.00
	Lightning	99.00	0.00%	0.00	0.00	0.00	0.00	0.00
	Rain	17.40	0.00%	0.00	0.00	0.00	0.00	0.00
	Snow/ Ice	23.00	0.00%	0.00	0.00	0.00	0.00	0.00
	Wind	21.80	0.00%	0.00	0.00	0.00	0.00	0.00
Work Procedure Error (WPE)	All types of WPE	20.20	0.00%	0.00	0.00	0.00	0.00	0.00

The ignition data used to populate the tables is in Section 3.2. See the notes regarding the data in that section.

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION PLAN
SECTION 4
INPUTS TO THE PLAN AND
DIRECTIONAL VISION FOR WILDFIRE RISK EXPOSURE

4 Inputs to the Plan and Directional Vision for Wildfire Risk Exposure

4.1 The Objectives of the Plan

The objectives of the plan shall, at a minimum, be consistent with the requirements of California Public Utilities Code §8386(a). Describe utility WMP objectives, categorized by each of the following timeframes:

- 1. Before the upcoming wildfire season, as defined by the California Department of Forestry and Fire Protection (CAL FIRE),
- 2. Before the next annual update,
- 3. Within the next 3 years, and
- 4. Within the next 10 years.

The objective of PG&E's Wildfire Mitigation Plan (WMP) for 2020 and beyond is to reduce the risk and consequences of wildfires associated with utility electrical equipment, and thereby avoid catastrophic wildfires across central and northern California. PG&E is investing in many wildfire mitigation measures including enhanced vegetation management, asset inspection and repair, situational awareness, system hardening, and system automation.

As climate change and associated fire risk worsens, the only certain way to prevent an ignition during high wind weather patterns is to deenergize utility equipment through a Public Safety Power Shut-off (PSPS). However, these PSPS events cause significant and serious disruptions to the customers and communities we serve. Therefore PG&E's 2020 WMP also focuses on reducing the scope (number of customers affected), frequency (number of events) and duration (length of outage) of PSPS events. We will mitigate PSPS impacts to our customers in 2020 and beyond by using advanced meteorology tools to forecast wildfire risk conditions more granularly, applying improved analysis of which parts of the system face high fire risk, and improving switching and sectionalization such that PSPS events affect smaller portions of the grid. PG&E believes these measures can shrink by one-third the number of customers affected by future PSPS events.¹ We have also adopted a new goal of conducting safety patrols and restoring service to 98% of PSPS-affected customers within 12 hours of the "weather all-clear" declaration. PG&E is also working to improve its coordination with state, local, and community agencies, and to provide extensive information and support to customers before, during and after PSPS events.

These objectives are summarized below and detailed in Section 5 of this WMP.

¹ As compared to the 2019 PSPS events, i.e. if the exact same weather patterns were seen in 2020 as experienced during the largest PSPS events in 2019 our mitigation efforts should reduce the number of customers impacted by those PSPS events by approximately one-third.

Progress Timeline

1. Before the upcoming wildfire season:

- Continue to reduce wildfire risk through mitigation programs including system hardening and enhanced vegetation management
- Implement PSPS impact mitigation activities to make each 2020 PSPS event affect one-third fewer customers than it would have in 2019 and to shorten restoration time after high-risk weather clears to 12 daylight hours for nearly all impacted customers.
- Further improve situational awareness and meteorology tools to increase weather forecast granularity and improve targeting of fire risk forecasts and PSPS events

2. Before the next annual update:

- Continue to modify wildfire mitigation programs by incorporating lessons learned throughout the 2020 wildfire season and in response to new regulations, requirements, guidelines or other changes.
- PG&E will work towards gathering data and performing the analysis necessary to establish modified PSPS criteria for distribution facilities that have been hardened.

3. Within the next 3 years:

- Track and assess performance of implemented wildfire risk mitigation activities to validate effectiveness and inform program adjustments. Evolve and implement wildfire mitigation programs, including increased annual pace of system hardening deployment.
- Continue to drive PSPS events to be smarter, smaller and shorter based on further improved tools, processes and understanding of wildfire risk and weather patterns.

4. Within the next 10 years:

- Track and assess performance of implemented wildfire risk mitigation activities over an extended period of time to validate effectiveness. Based on observed performance, continue using, modifying and improving elements of wildfire mitigation programs.
- Incorporate improving research, information, data, technologies and other tools into wildfire risk reduction efforts including PSPS targeting and minimization activities to continue to drive PSPS events to be smarter, smaller and shorter.

PG&E's Community Wildfire Safety Program (CWSP) is evolving rapidly as we gain experience on how various measures and technologies work to reduce the threat and

actuality of catastrophic wildfires. Actions such as vegetation management, equipment repairs, and line hardening are expected to materially reduce the risk, number and extent of wildfires – but at the same time, climate change-driven factors such as drought, wind patterns, bark beetles and others may increase that risk and counteract our efforts. PG&E seeks to study and learn about the impact and cost-effectiveness of the measure we take. We will work with our customers, communities and partners to learn how to serve their needs better and reduce wildfire and wildfire mitigation consequences in the future.

4.2 Understanding Major Trends Impacting Ignition Probability and Wildfire Consequence

Describe how the utility assesses wildfire risk in terms of ignition probability and estimated wildfire consequence, including use of Multi-Attribute Risk Score (MARS) and Multi-Attribute Value Function (MAVF) as in the Safety Model and Assessment Proceeding (S-MAP) and Risk Assessment Mitigation Phase (RAMP). Include description of how the utility distinguishes between these risks and the risks to safety and reliability. List and describe each “known local condition” that the utility monitors per GO 95, Rule 31.1, including how the condition is monitored and evaluated. In addition:

In this section, PG&E describes its use of the Multi-Attribute Value Function (MAVF) to assess wildfire ignition probabilities and estimated consequences. The MAVF was developed as a part of the California Public Utilities Commission’s (CPUC or Commission) Safety Model and Assessment Proceeding (S-MAP) and Risk Assessment Mitigation Proceeding (RAMP). This section also describes how it distinguishes between wildfire risk and other safety and reliability risks and lists and describes “known local conditions” as that term is used in General Order (GO) 95, Rule 31.1.

Section 4.2 is followed by Section 4.2(A) which addresses how PG&E monitors and accounts for the contribution of weather to ignition probability and estimated wildfire consequence in its decision-making, including describing any utility-generated Fire Potential Index (FPI) or other measure. Then, in Section 4.2(B), PG&E describes how it monitors and accounts for fuel conditions with regard to ignition probability and estimated wildfire consequence. Finally, in Section 4.2.1, PG&E provides a discussion of the fire-threat evaluation of its service territory to determine whether an expanded HFTD area is warranted. This section also includes Table 19. Naming and numbering conventions (e.g., Sections 4.2(A), 4.2(B), and 4.2.1) are consistent with the outline in the WMP Guidelines.

Implementation of the Multi-Attribute Value Framework (MAVF)

Pursuant to Decision (D.) 18-12-014, PG&E implemented the S-MAP Settlement Agreement in 2019, including the development of a MAVF and Risk Bowtie for Wildfire analysis. PG&E employs an MAVF to combine all potential consequences of the

occurrence of a risk event and create a single measurement of value.² An MAVF consists of the following components:

- Attributes / Ranges / Natural Units
- Weights
- Scaling Function

D.18-12-014 also provides six principles to use in determining the MAVF components: Attribute Hierarchies, Measured Observations, Comparison, Risk Assessment, Scaled Units, and Relative Importance.

The key components of the MAVF that PG&E used for assessing wildfire-related risks, and how they adhere to the principles, are shown Table PG&E-4-1 below and are described in the discussion following the table.

TABLE PG&E 4-1: KEY COMPONENTS OF MAVF

Attribute	Range	Natural Units	Weight	Scaling Function
Safety	0 - 100	Equivalent Fatalities (EF)/event	50%	Non-Linear
Electric Reliability	0 - 4 Billion	Customer Minutes Interrupted (CMI)/event	20%	Non-Linear
Gas Reliability	0 - 750,000	Customers affected/event	5%	Non-Linear
Financial ³	0 - \$5 Billion	\$/event	25%	Non-Linear

- Ranges: Pursuant to D.18-12-014, the smallest observable value of an Attribute is the low end of the range, and the largest observable value is the high end of the range. PG&E interprets the largest observable value to be a reasonable value informed by historical events and plausible large-consequence scenarios. In PG&E's analysis and risk framework, event consequences are not capped at

² D.18-12-014, p. 17, 2018 S-MAP Revised Lexicon: *Multi-Attribute Value Function (MAVF)*.

³ Pursuant to D.18-12-014 and D.16-08-018, utility shareholders' financial interests are to be excluded from the GRC and RAMP risk evaluation and risk mitigation considerations.

the high end of the range, but rather, the range is a specification required in the scaling function.

- The high end of the Safety Attribute Range, set to 100, is an order-of-magnitude value informed by recent events.
 - The high end of the Electric Reliability Range (4 Billion CMI) was based on the most severe reliability impact from a single event of 3.6 billion CMI from the October 26, 2019 PSPS event.
 - The Gas Reliability high end is based on a scenario of an outage at a critical gas facility.
 - The Financial Attribute's high end represents a financial loss commensurate with an Energy Crisis-type event.
- **Natural Units:** EF is defined as the sum of Public, Employee and Contractor Fatalities and Serious Injuries per event occurrence. Serious Injuries are defined as situations that require hospitalization of an individual pursuant to existing Federal and State reporting guidelines.^{4,5} Fatalities and Serious Injuries are converted to EFs using the multiplicative factors 1.00 and 0.25, respectively. The conversion rate from Serious Injury to EF is based on information available from Federal sources.⁶
 - **Scaling Function:** The Non-Linear Scaling Function is used to convert each Attribute from its Natural Unit to Scaled Units.⁷ It consists of the following segments, with each segment intended to represent events that are either operational (i.e., encountered in the course of regular operations), critical or catastrophic.
 - For natural units from 0 to 1% of the Range (operational/moderate events): Linear function from 0 to 0.1 Scaled Units.

⁴ Pipeline and Hazardous Materials Safety Administration (PHMSA) §191.3 Definitions: Incident (see also: <https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-facility-incident-report-criteria-history>).

⁵ D.98-07-097 (Amended April 27, 2006), Findings of Fact 3 and Appendix B, Accident Report Requirements 3 (see also: <https://www.cpuc.ca.gov/General.aspx?id=2090>).

⁶ See "Treatment of the Values of Life and Injury in Economic Analysis", Table 2-3, Federal Aviation Administration (FAA) Office of Aviation Policy and Plans, Updated September 2016, (available at: https://www.faa.gov/regulations_policies/policy_guidance/benefit_cost/media/econ-value-section-2-tx-values.pdf).

⁷ D.18-12-014, pp. 17-18; 2018-S-MAP Revised Lexicon: *Scaled Unit of an Attribute: a value that varies from 0 to 100.*

- For natural units from 1% to 10% of the Range (critical events): Quadratic function from 0.1 to 5 Scaled Units.
- For natural units from 10% to 100+% of the Range (catastrophic events): Linear function from 5 to 100 Scaled Units.

D.18-12-014 directs utilities to use Expected Value (EV) when calculating the Consequence of Risk Event (CoRE) and use the scaling function to capture aversion to extreme outcomes or indifference over a range of outcomes. Under PG&E's Non-Linear scaling function, the risk score, as measured by Scaled Units, will be low for operational events, but increases exponentially as critical events approach catastrophic (but low probability) levels. Once catastrophic levels are attained the function assigns 10 times higher score for each potential increase in Natural Units when compared to operational events. This captures aversion to critical and catastrophic outcomes and gives higher priority to controls and mitigations that affect them.

When PG&E evaluates potential event consequences, it does not cap them at the Range high end per se, but pursuant to D.18-12-014⁸, PG&E places a ceiling of 100 on converted Scaled Units, i.e., if a modeled risk event's consequence in Natural Units goes above the Attribute Range, the converted Scaled Unit will be 100. This provides a way to compare the relative importance of different Attributes using Attribute Weights, consistent with the Relative Importance principle.⁹ Also, by capping, PG&E recognizes that catastrophic risks must be mitigated, and it is immaterial to consider one risk to be "more" or "less" catastrophic than another (e.g., a financial loss of \$5 billion or \$5.2 billion) when evaluating alternatives.

Environmental consequences of an event are accounted for financially (i.e., as part of the Financial consequences) because there is a lack of commonly accepted ways to measure non-monetary environmental consequences. This makes the use of non-monetary environmental Attributes inconsistent with the principle of Measured Observations.

In PG&E's risk modeling, Attribute levels (e.g. the financial consequence of a risk event) are assumed to be uncertain and are represented by well-defined probability distributions. PG&E uses Monte-Carlo simulations of risk events based on these probability distributions to calculate MAVF consequence levels (in Scaled Units) and thus Risk Scores, consistent with the Risk Assessment principle.

Wildfire Risk Assessment

Consistent with D.18-12-014, PG&E assesses wildfire risk and estimated wildfire consequences in a bowtie analysis.

⁸ *Id.*

⁹ D.18-12-014, Attachment A, Step 1A, No 7. MAVF Principle 6 – Relative Importance. pp A-6.

FIGURE PG&E 4-1: WILDFIRE RISK “BOWTIE” ANALYSIS



1. Below, PG&E provides a summary of wildfire bowtie analysis elements. Ignition Probability in the current S-MAP conforming bowtie is derived from normalizing the ignitions by Transmission and Distribution overhead line miles of exposure reported annually to the CPUC. In accordance with D.14-02-015, PG&E annually reports to the CPUC fire incidents that may be associated with PG&E facilities and that meet the following conditions: (a) a self-propagating fire of material other than electrical and/or communication facilities; (b) the resulting fire traveled greater than one linear meter from the ignition point; and (c) PG&E has knowledge that the fire occurred. The S-MAP conforming model currently has ignitions reported to the CPUC for years 2015 through 2018. Though PG&E is still reviewing the 2019 data in preparation for its annual report, preliminary 2019 data is also used in the model.¹⁰
2. Total Exposure across all Tranches: 98,965 miles covering PG&E's service territory
3. Ignitions are broken down to Six Tranches to reflect similar risk profiles within each Tranche:
 - HFTD – Ignition Associated with Distribution: Ignitions in HFTDs associated with Distribution assets.
 - HFTD – Ignition Associated with Transmission: Ignitions in HFTDs associated with Transmission assets.
 - HFTD – Ignition Associated with Substation: Ignitions in HFTDs associated with Substation.
 - Non HFTD – Ignition Associated with Distribution: Ignitions in non-HFTDs associated with Distribution assets.
 - Non HFTD – Ignition Associated with Transmission: Ignitions in non-HFTDs associated with Transmission assets.
 - Non HFTD – Ignition Associated with Substation: Ignitions in non-HFTDs associated with Substations.
4. Wildfire Consequences are modeled by analyzing fire incidents from CAL FIRE database from 2015 - 2019. CAL FIRE dataset provides location, size, number of destroyed/damaged structures and fatalities/injuries. This information is used to estimate financial and safety consequences. Reliability consequences are estimated by using distribution customer minutes interrupted for outages that were associated with CPUC reportable ignitions as well as outages associated with PG&E known fires.

¹⁰ PG&E's 2019 fire incident data will be submitted to the CPUC by April 1, 2020 per D.14-02-015. As such, PG&E's 2019 fire incident data report may contain data that has been revised from the data used in this risk analysis.

5. Outcomes – Consequences are categorized into eight outcomes to account for the severity of the fire as well as whether a fire weather warning was in place at the time of the start of the fire:

- Fire Weather Warning* – Catastrophic Fire (Destroyed +100 structures and resulted in serious injury / Fatality)
- Fire Weather Warning – Destructive Fire (Destroyed +100 structures but not Catastrophic)
- Fire Weather Warning – Large Fire (Greater than 300 acres but not Catastrophic/Destructive)
- Fire Weather Warning – Small Fire (Smaller than 300 acres)
- Non-Fire Weather Warning – Catastrophic Fire (Destroyed +100 structures and resulted in serious injury / Fatality)
- Non-Fire Weather Warning – Destructive Fire (Destroyed +100 structures but not Catastrophic)
- Non-Fire Weather Warning – Large Fire (Greater than 300 acre but not Catastrophic/Destructive)
- Non-Fire Weather Warning – Small Fire (Smaller than 300 acre)

Wildfire Risk Assessment Compared with Other Safety and Reliability Risks

All Enterprise Risks on PG&E's Risk Register might have safety and reliability consequences. The consequences are modeled separately for each risk. In developing probabilities and consequences for wildfire risks, PG&E uses a mix of internal and external data to model wildfire drivers and consequences (safety and reliability impacts on the risk). Safety and Reliability consequences/attributes (per S-MAP terminology) are also modeled separately and combined into a risk score using the MAVF.

List and Description of “Known Local Conditions” as That Term is Used in GO 95, Rule 31.1

GO 95, Rule 31.1 directs PG&E to design, construct and maintain a facility in accordance with accepted good practice for the intended use and known local conditions. For the purposes of risk assessment, PG&E utilized HFTD and non-HFTD areas as its known local conditions. PG&E developed its S-MAP conforming bowtie for the wildfire risk by creating separate tranches for HFTD and non-HFTD areas. The higher risk scores and Risk Spend Efficiency values for mitigations in the HFTD areas enables a clear case for prioritization of wildfire mitigation initiatives in HFTD areas. See Section 4.2.1 for additional information on PG&E's evaluation of HFTD areas.

4.2.A Contribution of Weather to Ignition Probability and Estimated Wildfire Consequences

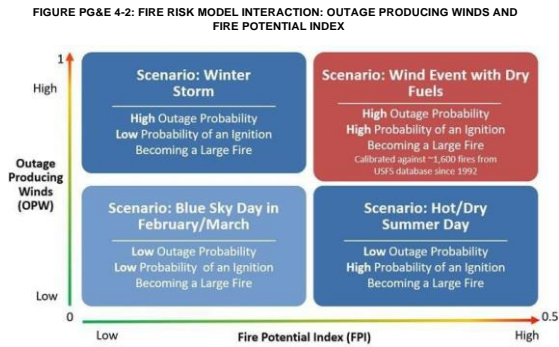
- A. *Describe how the utility monitors and accounts for the contribution of weather to ignition probability and estimated wildfire consequence in its decision-making, including describing any utility-generated Fire Potential Index or other measure (including input variables, equations, the scale or rating system, an explanation of how uncertainties are accounted for, an explanation of how this index is used to inform operational decisions, and an explanation of how trends in index ratings impact medium-term decisions such as maintenance and longer-term decisions such as capital investments, etc.).*

PG&E currently evaluates the risk of fires caused by a utility source as the product of the probability of an event occurring and the event consequence. The probability of a utility-caused fire ignition is related to a power outage from any source (e.g., vegetation failure, equipment failure, animal contact, car-pole). To better understand and forecast the potential of an outage, PG&E developed and then operationally deployed the Outage Producing Wind (OPW) model. The OPW model is incorporated into PG&E's high-resolution weather model and runs 4 times daily, and has also been computed hourly across PG&E's 30-year climatological dataset for historical analysis. PG&E's OPW model is discussed in detail in Section 5.3.2.

In order to evaluate the potential for fires, PG&E significantly enhanced the Fire Potential Index (FPI) model in 2019 building upon utility best-practices. The FPI model was built and calibrated using a United States Forest Service (USFS) dataset containing approximately 1,600 fires in PG&E's service territory from 1992 – 2018. PG&E built and evaluated over 4,000 combinations of the FPI model using numerous weather components, fire weather indices (Fosberg Fire Weather index, the Hot-Dry-Windy Index, the Santa Ana Wildfire Threat weather index), outputs from the National Fire Danger Rating System (NFDRS), Nelson Dead Fuel Moisture (DFM) model, a machine-learning derived Live Fuel Moisture (LFM) model, and 'containment' and 'land characteristic' features such as road density, distance to nearest fire station, land-use type among several others. PG&E evaluated dozens of variables to determine the most powerful predictors of fire size. The enhanced PG&E FPI, which was operationally deployed in 2019, combines weather (wind, temperature, and relative humidity) and fuels (10-hour dead fuel moisture, live fuel moisture, and fuel type [grass, shrub/brush, timber]) into an index that represents the probability for large fires to occur. The FPI is discussed in more detail in Section 5.3.2. The FPI is also produced 4 times daily from PG&E's high-resolution weather model, DFM and LFM models and was also computed hourly across PG&E's 30-year climatological dataset for historical analysis.

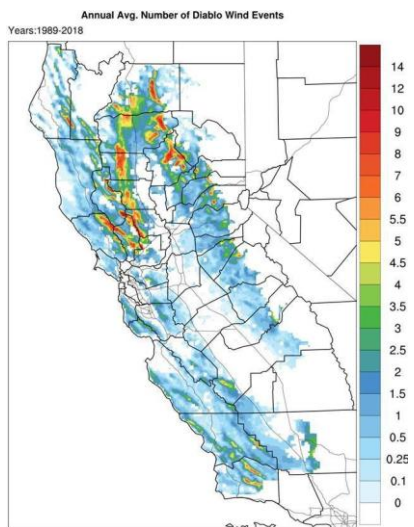
The FPI and OPW models are used in unison to analyze the risk of large fires caused by utility outages. For example, when the potential for outages is high (high OPW) and the potential for large fires is high (high FPI), a PSPS event should be considered. PG&E leveraged a robust 30-year weather and fuels dataset to determine the OPW and FPI conditions during each historical fire in the USFS fire occurrence dataset. The results showed the vast majority of rapidly moving, catastrophic fires occurred during high wind and high FPI conditions; thus, PG&E currently considers PSPS when there is a concurrence of high OPW and FPI. See the illustrative example below. PG&E currently has the ability to forecast FPI and OPW at 3 kilometer (km) spatial resolution

and 1-hour temporal resolution using PG&E's high-resolution weather model that has a forecast lead time of 80 hours. This modeling capability informs operational decisions in the short term. Beyond 80 hours, PG&E leverages global forecast models (discussed in Section 5.3.2) to help inform any operational and preparedness actions over the next two weeks.



PG&E Meteorology has a robust 30-year weather and fuels climatology that is being utilized to study past weather patterns across the PG&E service territory. One application is to determine where dry offshore wind events most frequently occur and when. These offshore wind events are commonly known as Diablo or Santa Ana wind events. The Diablo wind is a dry, northeast wind that occurs over northern California and is comparable to Santa Ana winds. These events are critical to consider as the vast majority of destructive fires in California history have occurred during dry, offshore wind events. The image below presents the average frequency of offshore (Diablo) wind events across the PG&E territory. For this analysis, a dry, Diablo wind event was defined as an event lasting at least 3 hours, having sustained winds >20 mph, wind direction from the north to northeast (offshore), and a PG&E FPI indicating dry conditions. This analysis shows the relative frequency of these events is higher in the North Bay Area and northern Sierra than in other portions of the PG&E territory. This study also revealed dry, offshore wind events are most common in Autumn. These patterns generally held true in 2019 as the majority of PSPS events occurred during autumn across the northern half of PG&E's territory. This analysis as well as other historical analyses are currently being considered for longer term projects such as grid hardening, enhanced vegetation management, and others.

**FIGURE PG&E 4-3: 30-YEAR HISTORICAL ANNUAL AVERAGE OF "DIABLO WIND EVENTS"
GEOGRAPHICALLY**



PG&E monitors and accounts for the contribution of weather to ignition probability and estimated wildfire consequences in the S-MAP conforming bowtie by separating out the risk into separate outcomes based on historical fire weather watch data. See Section 4.2 above for the eight outcome categories. PG&E's risk analysis is then used to inform medium- and long-term decisions to address wildfire mitigation, such as inspections, maintenance, and capital investments. PG&E is also using historical PSPS events and their calculated expected risk to develop mitigations through either repairs, replacements, or sectionalizing plans. The calculated risk is a combination of the Asset Health predictive failure with the event FPI and REAX model.

4.2.B Contribution of Fuel Conditions

- B. *Describe how the utility monitors and accounts for the contribution of fuel conditions to ignition probability and estimated wildfire consequence in its decision-making, including describing any proprietary fuel condition index (or other measures tracked), the outputs of said index or other measures, and the methodology used for projecting future fuel conditions. Include discussion of measurements and units for live fuel moisture content, dead fuel moisture content, density of each fuel type, and any other variables tracked. Describe the measures and thresholds the utility uses to determine extreme fuel conditions, including what fuel moisture measurements and threshold values the utility considers "extreme" and its strategy for how fuel conditions inform operational decision-making.*

PG&E's FPI, Dead Fuel Moisture, and Live Fuel Moisture modeling and tracking is discussed in detail in Section 5.3.2.

4.2.1 Service Territory Fire-Threat Evaluation and Ignition Risk Trends

Discuss fire-threat evaluation of the service territory to determine whether an expanded High Fire Threat District (HFTD) is warranted (i.e., beyond existing Tier 2 and Tier 3 areas). This section shall include a discussion of any fire threat assessment of its service territory performed by the electrical corporation. In the event that the electrical corporation's assessment determines the fire threat rating for any part of its service territory is insufficient (i.e., the actual fire threat is greater than what is indicated in the CPUC Fire Threat Map and High Fire Threat District designations), the corporation shall identify those areas for consideration of HFTD modification, based on the new information or environmental changes. To the extent this identification relies upon a meteorological or climatological study, a thorough explanation and copy of the study shall be included.

PG&E believes that the current HFTD map appropriately identifies areas within its service territory requiring additional actions to reduce wildfire risk. However, as a result of experience gained and feedback received in 2019, PG&E believes that elements of the HFTD map may warrant refinement. In addition, development and completion of a re-analysis of 30-year climatology and completion of the first phase of industry and agency accepted modeling provided by Technosylva can also be used to refine the HFTD map. As a result of this updated data, PG&E plans to perform additional evaluations of the HFTD map. These evaluations will help refine the scope of areas subject to PSPS, as well as, identify areas where adjustment to the HFTD map may be recommended by the utility.

In early 2020, PG&E plans to implement the first phase of this evaluation process. PG&E will execute an internal workplan much like the plan that helped develop the CPUC's HFTD map. This will rely on local expertise, defined data, and developed models to be utilized by regional leads to review and refine recommendations. These recommendations will be evaluated by a centralized review team and consolidated by these internal experts.

Following the first phase, PG&E will share outputs and recommendations with external stakeholders and public safety partners. This second phase is a critical step to ensure

any map revisions are vetted and socialized before proposing formal changes to the HFTD map to the CPUC. PG&E anticipates a significant amount of external engagement regarding these critical and potentially impactful adjustments. Refining and minimizing the impacts of potential PSPS events is an expectation in 2020. It is also anticipated that this process will clearly identify opportunities for future HFTD map refinement should the CAL FIRE and the CPUC endorse the changes.

PG&E will continue to evaluate the inclusion of additional areas requiring wildfire reduction activity in future plans based upon information obtained during the implementation and evaluation of PG&E's annual plan. In addition, PG&E will continue to mature its tools to analyze wildfire risk using available data, climatology and fire spread modeling to inform potential adjustments to the HFTD. These analytics may lead to additional future recommendations.

Instructions for Table 19:

In the "Rank" column, numerically rank the trends anticipated to exhibit the greatest change and have the greatest impact on ignition probability and estimated wildfire consequence (be it to increase or decrease ignition probability and estimated wildfire consequence) in ten years. Rank in order from 1 to 8, where 1 represents the greatest anticipated change or impact on ignition probability and estimated wildfire consequence and 8 is the least anticipated change or impact.

In the "Comments" column, provide a narrative to describe the expected change and expected impact on the utility's network, including whether the trend is expected to significantly increase risk, moderately increase risk, have limited or no impact, moderately decrease risk, or significantly decrease risk. Use quantitative estimates wherever possible. Also outline any programs being implemented to specifically address this trend.

TABLE 19: MACRO TRENDS IMPACTING IGNITION PROBABILITY AND/OR WILDFIRE CONSEQUENCE

Rank	Macro trends impacting utility ignited ignition probability and estimated wildfire consequence by year 10	Comments
1	Change in ignition probability and estimated wildfire consequence due to climate change	<p>Several key climate change trends are influencing variable periods of extreme wildfire risks in Northern California. These trends significantly increase wildfire ignition risks around utility networks.</p> <p>Warmer winters are causing increases in rainfall rather snow, resulting in a decrease to the snowpack. This reduces available water resources earlier in summer months, stressing vegetation and increasing available fuels. Compounding the shift from snow to rain are extended dry periods following summer months deeper into fall and early winter. Northeast winds are more common in fall and winter months in Northern California and if not accompanied by rainfall or other atmospheric moisture wildfire risks continue to increase despite the presence of lower temperatures. Ignitions that occur under these conditions can result in large conflagrating wildfires that can further promote risk associated with Northern California's abundant fuel and extreme terrain resulting in fires that develop their own devastating weather.</p> <p>Reference OEHHA: https://oehha.ca.gov/epic/changes-climate/precipitation</p> <p>"Extremely dry and extremely wet years have become more common in California. On average, the state receives 75 percent of its annual precipitation from November through March, with 50 percent occurring from December through February. As the winter months have become warmer in recent years, more precipitation has been falling as rain instead of snow over the watersheds that provide most of the state's water supplies." "The last decade also includes the driest consecutive four-year period, from 2012 to 2015."</p> <p>"Warming temperatures, declining snowpack, and earlier spring snowmelt runoff can create stresses on vegetation"</p> <p>Reference National Geographic : https://www.nationalgeographic.com/science/2019/10/climate-change-california-power-outage/</p>

TABLE 19: MACRO TRENDS IMPACTING IGNITION PROBABILITY AND/OR WILDFIRE CONSEQUENCE (CONTINUED)

Rank	Macro trends impacting utility ignited ignition probability and estimated wildfire consequence by year 10	Comments
3	Change in ignition probability and estimated wildfire consequence due to relevant invasive species, such as bark beetles	<p>Invasive species create landscape level concerns that have significant potential to impact areas within utility right-of-ways (ROW). Effects can extend well beyond the ROW making effective mitigation challenging for utilities without more holistic engagement and support from surrounding stakeholders.</p> <p>Of concern to utilities are both invasive plant species and insect species.</p> <p>Invasive insect species, such as bark beetles, can exacerbate forest health concerns and result in hazardous tree conditions that require repetitious monitoring and mitigation by utilities. Native species can impose the same impacts and challenges.</p> <p>Invasive plant species in California tend to thrive in disturbed environments, often displacing native species. There is evidence that these invasions can change and intensify fire regimes. Landscape disturbance can be presented following fires, as well as during ROW maintenance and enhancements. Regardless of disturbance origin utilities are continually compelled to perform additional monitoring and mitigation to identify and control detrimental impacts associated with invasive species.</p> <p>References</p> <p>Emergency Proclamation – Office of Governor https://www.ca.gov/archive/gov39/2015/10/30/news19180/index.html</p> <p>PNAS- <i>Invasive grasses increase fire occurrence and frequency across US ecoregions</i></p> <p>"Fire-prone invasive grasses create novel ecosystem threats by increasing fine-fuel loads and continuity, which can alter fire regimes." "the existence of an invasive grass-fire cycle is well known, evidence of altered fire regimes is typically based on local scale studies or expert knowledge." "As concern about US wildfires grows, accounting for fire-promoting invasive grasses will be imperative for effectively managing ecosystems."</p>

**TABLE 19: MACRO TRENDS IMPACTING IGNITION PROBABILITY AND/OR WILDFIRE
CONSEQUENCE (CONTINUED)**

Rank	Macro trends impacting utility ignited ignition probability and estimated wildfire consequence by year 10	Comments
		CalFire – https://www.readyforwildfire.org/forest-health/bark-beetle-information/about-bark-beetles/
2	Change in ignition probability and estimated wildfire consequence due to other drivers of change in fuel density and moisture	<p>PG&E's service territory has experienced noteworthy changes in both fuel density and moisture over the last several decades. These trends significantly increase wildfire ignition risks around utility networks.</p> <p>Fuel density is increasing while available moisture in critical wildfire risk periods is decreasing. This has been accompanied by increases in large tree mortality and overall changes in forest structure. Contributing factors cover a wide range of influences, including but not limited to; climate change, land use patterns, fire suppression and variable forest management practices.</p> <p>Forests are becoming denser with decreased presence of large trees and significant tree mortality over the last decade. Lands that are left unmanaged are subject to increases in accumulated dead and downed fuels that can be annually influenced by surrounding finer, flashier fuels following periods of sufficient rain or snowfall.</p> <p>Reference PNAS: https://www.pnas.org/content/112/5/1458</p> <p>Reference California Energy Commission: https://www.energy.ca.gov/sites/default/files/2019-07/Projections_CCCAF-CEC-2018-014.pdf</p>

TABLE 19: MACRO TRENDS IMPACTING IGNITION PROBABILITY AND/OR WILDFIRE CONSEQUENCE (CONTINUED)

Rank	Macro trends impacting utility ignited ignition probability and estimated wildfire consequence by year 10	Comments
5	Population changes (including Access and Functional Needs population) that could be impacted by utility ignition	<p>Population in California and PG&E's territory continue to show projections for growth in decades to come. A fair amount of this growth continues in lands previously undeveloped and bordering fire prone wildland areas. Many utility customers have left the urban environment in favor of more fire prone areas for reasons beyond the associated risk. Current estimates suggest that at least 25% of California's residents already have residence in areas subject to significant wildfire risk. With projection of upward population trends continuing, it is likely that Wildland Urban Interface (WUI) and/or the CPUC HFTD areas will not be exceptions to increases. The available space and desire to live in safer urban areas in the PG&E territory are realistic factors that must be considered in reaching these conclusions. Variable portions of these increases will include customer with supplemental access and other functional needs.</p> <p>Utilities will need to engage in programs and education campaigns that inform and prepare all customers to mitigate consequence of these eminent risks.</p> <p>References</p> <p>LCAU - https://lcau.mit.edu/project/cataloguing-interface-wildfire-and-urban-development-california</p> <p>PPIC - https://www.ppic.org/content/pubs/report/R_116HJ3.R.pdf</p> <p>CNBC - Warming climate, population sprawl threaten California's future with more destructive wildfires - https://www.cnn.com/2019/11/09/why-californias-wildfires-are-going-to-get-worse.html</p>
6	Population changes in HFTD that could be impacted by utility ignition	See response item ranked "5". Given the overall area of the HFTD as a percentage of PG&E's service territory, it is likely that population growth in the HFTD areas will not be an exception to anticipated trends.

TABLE 19: MACRO TRENDS IMPACTING IGNITION PROBABILITY AND/OR WILDFIRE CONSEQUENCE (CONTINUED)

Rank	Macro trends impacting utility ignited ignition probability and estimated wildfire consequence by year 10	Comments
7	Population changes in WUI that could be impacted by utility ignition	See response item ranked "5". Given the overall area of the WUI as a percentage of PG&E's service territory, it is likely that population growth in WUI will not be an exception to anticipated trends. The HFTD map was informed by WUI data and tremendous overlap between the two categories exists within PG&E service territory.
4	Utility infrastructure location in HFTD vs non-HFTD	Location of utility infrastructure in the HFTD areas needs to be considered as a risk mitigating factor by utilities. Siting decisions associated with infrastructure placement should complement other resiliency and hardening programs continually over the decades to come. Position of infrastructure and imposed risk can vary tremendously in the HFTD areas based on a multitude of terrain, aspect and exposure factors which are in many cases also realistic limitations. For these reasons the location of infrastructure in the HFTD areas will realize more significant changes in the HFTD areas compared to Non-HFTD areas.
8	Utility infrastructure location in urban vs rural vs highly rural areas	See response to item ranked "4". There is high correlation between the HFTD areas and rural communities. There is similar correlation between urban areas and non-HFTD areas.

List and describe any additional macro trends impacting ignition probability and estimated wildfire consequence within utility service territory, including trends within the control of the utility, trends within the utility's ability to influence, and externalities (i.e., trends beyond the utility's control, such as population changes within the utility's territory).

Macro Trends Impacting Ignition Probability and Wildfire Consequences Within PG&E's Control:

- Enhanced Vegetation Management (EVM) – Maintaining additional clearances through highly variable annual conditions and vegetation responses to increased pruning and clearances. New failure patterns can arise when previously unmanaged trees are trimmed, pruned or modified well outside regulatory compliance clearance areas.
- Asset Inspection and Repair – Inspecting facilities, especially in HFTDS areas, and performing necessary maintenance and repair

- System Hardening – Identifying the most effective hardening and system resilience mitigation combinations to complement enhanced vegetation management practices.
- System Automation – Electrical equipment such as sectionalization switches and SCADA-enable reclosers that can prevent and mitigate wildfires.
- PSPS – Use of PSPS events to mitigate fire risk under extremely high-risk conditions.
- Situational Awareness – Weather and fire monitoring through tools such as weather stations, high-definition cameras, wires-down detection, automated rapid earth fault current limiters, satellite monitoring, and other tools to enhance situational awareness.
- Wildfire Safety Operations Center – coordination of fire detection and mitigation activities through PG&E's Wildfire Safety Operations Center.
- Meteorology – Monitoring and integration of weather information through PG&E's meteorology department in coordination with external partners.
- Safe Distributed Generation – Ensuring distributed generation is safely installed and coordinates with designed distribution scheme
- Qualified Workforce -- Maintaining a safe and qualified workforce. Qualified Electrical Workers and Vegetation Management Professionals are all in high demand inside and outside California.

Macro Trends Impacting Ignition Probability and Wildfire Consequences with PG&E's Ability to Influence:

- Effective Regulation – Work with agencies and regulators on solutions that better align with utility infrastructure and risks that conflict with other regulations and/or land-use
- Fuel Reduction – Work with agencies to ensure utilities are involved in pre-planning and execution of prescribed burning to maximize safety in operations and reduce wildfire fuel
- Safe Backup Generation – Ensuring customer that install backup generation do so in compliance with electric code
- Fire Safe Planning: Customer – Coordinate and find ways to collaborate with individual customers and property owners to maximize wildfire prevention and safety measures
- Fire Safe Planning: Community - Coordinate and find ways to collaborate with community-partners and organizations to maximize wildfire prevention and safety measures
- Point of Service Termination Electric Load Monitoring – Ability to monitor and measure use that exceeds design or use capacity as built and serviced

- Working to reduce 3rd party caused utility ignitions – Identify specific mitigation or educational opportunities to reduce 3rd party caused utility ignitions

Macro Trends Impacting Ignition Probability and Wildfire Consequences with Externalities (i.e., Beyond PG&E's Control):

- Climate Change – Warmer winters less snow pack, longer dry periods extending into fall and winter months
- Development and population increase in High Risk Areas – Continued urban expansion/sprawl into Wildland Urban Interface and HFTD areas. Potential for increase in vulnerable populations as well as general populations
- Environmental Restrictions and Work Approval Delays or Limitations – Limitations on timing and/or ability to perform critical fire safety related work and mitigation. Limited Operating Periods, limitations on utilization of EPA approved herbicides. Delays in reviews, complex permitting process, etc.
- Land Management Practices Private and Public – Variable levels of fire safe/prudent land management
- Substandard or minimal defensible space around improvements – Hazardous conditions present adjacent to ROWs that meet and exceed regulatory compliance requirements can still impose hazards associated with utility related ignitions

List and describe all relevant drivers of ignition probability and estimated wildfire consequences and the mitigations that are identified in the Risk Assessment Mitigation Phase (RAMP) and not included in the above, including how these are expected to evolve. Rank these drivers from highest to lowest risk and describe how they are expected to evolve.

See the S-MAP Aligned Risk Bowtie in Section 4.2 above for the relevant drivers of ignitions and estimated wildfire consequences Section 3.2, Table 11 also list the drivers of ignition probability.

See Section 4.3 below for information on how these drivers are expected to evolve, and their ranking.

4.3 Change in Ignition Probability Drivers

Based on the implementation of the above wildfire mitigation initiatives, explain how the utility sees its ignition probability drivers evolving over the 3-year term of the WMP. Focus on ignition probability and estimated wildfire consequence reduction by ignition probability driver, detailed risk driver, and include a description of how the utility expects to see incidents evolve over the same period, both in total number (of occurrence of a given incident type, whether resulting in a near miss or in an ignition) and in likelihood of causing an ignition by type. Outline methodology for determining ignition probability from events, including data used to determine likelihood of ignition probability, such as past ignition events, number of near misses, and description of events (including vegetation and equipment condition).

PG&E estimates a 10% reduction in vegetation-caused, equipment failure and animal-caused ignitions from the 2019 level due to planned System Hardening, Enhanced Vegetation Management and tag repair work that is planned for 2020 onwards. The 10% reduction is derived from the risk prioritization of work and an estimation of the combined CWSP mitigation effectiveness and associated ignition risk reductions. The same reduction trend of 10% is anticipated in 2021 and 2022.

PG&E assumes that in each of the years 2020- 2022, the ignition to incident ratio remains as same as that in 2019 in Table 11. PG&E utilizes the 2019 ignition to incident ratio along with the estimated mitigated ignitions (10% reduction for the abovementioned drivers) in each of the years 2020-2022 in order to calculate the incident frequencies in each of the years 2020-2022.

In total, based on this analysis, PG&E estimates an ~8% reduction for all HFTD ignitions, year over year, for 2020, 2021 and 2022.

See Section 5.6.1, Table 31 for the analysis of the ignition change for each of the drivers. Drivers may be ranked based on the metrics provided in the Table.

4.4 Directional Vision for Necessity of PSPS

Describe any lessons learned from PSPS since the utility's last WMP submission and expectations for how the utility's PSPS program will evolve over the coming 1, 3, and 10 years. Be specific by including a description of the utility's protocols and thresholds for PSPS implementation. Include a quantitative description of how the circuits and numbers of customers that the utility expects will be impacted by any necessary PSPS events is expected to evolve over time. The description of protocols must be sufficiently detailed and clear to enable a skilled operator to follow the same protocols.

When calculating anticipated PSPS, consider recent weather extremes, including peak weather conditions over the past 10 years as well as recent weather years and how the utility's current PSPS protocols would be applied to those years.

Lessons Learned from the PSPS Events

Since the 2019 WMP submission, PG&E executed a number of PSPS events on a widespread scale ranging from approximately 10,000 customers to nearly 1 million customers.¹¹ In comparison, at the time of the 2019 WMP submission, PG&E had executed one PSPS event impacting 60,000 customers. The PSPS events in 2019 provided PG&E with insight for improvement going forward, including experience with the significant scale and consecutive nature in which PSPS events can materialize. Following the 2019 PSPS events, in addition to the focus of eliminating catastrophic wildfire risk, a critical objective of the 2020 WMP is to accelerate measures to dramatically reduce customer impacts of PSPS events *without* compromising safety. Actions planned to achieve this objective following the execution of PSPS in 2019 are described further below in the subsection entitled *Evolutions of the PSPS Program*.

In addition, the extensive implementation of PSPS events in 2019 resulted in the identifications of key focus areas to improve internal PSPS execution processes and tools. PG&E staff and contractors documented real-time observations from participants involved in the PSPS process throughout the entirety of each PSPS event, and after-action review workshops were conducted following events. The key lessons learned were summarized in each PG&E De-energization Report submission to the CPUC in compliance with Resolution ESRB-8. Based on the cumulative lessons learned, PG&E has identified the following seven priority areas for internal process improvement, including scaling of web and call operations which was identified and addressed during 2019 PSPS execution as opposed to identification through after-action reviews. This list is not intended to be comprehensive of all lessons learned, but rather reflects priority corrective action areas to immediately address for improved process execution in the upcoming 2020 wildfire season.

1. External Communication and Coordination: Understand and address the

¹¹ PG&E's measure of customers is based on customer accounts, *i.e.* active service points. A single customer account can serve multiple individuals. PG&E does not have visibility to the number of individuals that each account holder represents, and therefore, refers to and quantifies each customer account as a "customer" in normal business operations and throughout this report.

information needs of customers and state, local, and tribal partners. Improve the communication processes for sharing relevant information, including accuracy and timeliness.

2. **Scaling of Web and Call Center Operations:** Prepare and scale for significant increases in customers contacting PG&E during PSPS events. Plan for both website and call center operations to meet maximum potential traffic requirements including contingency so that both web and call services are available at all times.
3. **Data Quality:** Improve the quality and governance of PSPS-related data throughout PG&E's internal databases to support more efficient, timely, and accurate internal execution processes and provide more accurate stakeholder communications.
4. **Map Accuracy and Availability:** Better assist external stakeholders with their PSPS planning and preparations by providing additional customer detail and increasing the precision and timeliness of scoping maps provided during PSPS events.
5. **Scoping Process and Tool Enhancements:** Improve the agility and accuracy of scoping tools and processes to increase the efficiency and limit the disruption of scope changes as weather conditions change during an event.
6. **Estimated Time of Restoration:** Improve the accuracy and timeliness of generating and externally communicating estimated times for restoration following de-energization.
7. **Staffing Model:** Develop strategies to increase the flexibility of staffing models and number of trained and expert PSPS personnel to limit the mental and physical fatigue of employees across multiple sustained PSPS events.

Evolution of the PSPS Program

To address the critical objective of reducing PSPS impacts without compromising safety, PG&E is working to identify and develop mitigation strategies for near-term and long-term implementation. The key initiatives identified to both reduce the scope, duration, and frequency of future PSPS events as well as to mitigate impacts on de-energized customers in future events are summarized below and detailed in subsequent sections. These initiatives and strategies may be adjusted as PG&E continues to evaluate viable opportunities and there may be additional ways in which the PSPS program evolves, including stakeholder input and Commission direction through the Order Instituting Investigation (I.) 19-11-013 and Rulemaking (R.) 18-12-005.

Distribution Segmentation and System Hardening

PG&E's plan is to enhance its distribution segmentation strategies including:
a) adding sectionalizing devices, b) circuit reconfiguration / pre-PSPS event switching, and c) additional system hardening to support PSPS switching. PG&E has identified various distribution lines where additional switching devices coupled with targeted system hardening can be utilized to further sectionalize

distribution feeders to minimize the number of customers being impacted by PSPS outages. Additional information can be found in Section 5.3.3.8.

Transmission Line Sectionalizing

PG&E plans to enhance transmission segmentation strategies including installation of additional SCADA-controlled switches. PG&E has identified various transmission lines where additional switching devices will be utilized to further sectionalize transmission lines to be able to minimize the number of customers impacted by PSPS outages. Additional information can be found in Section 5.3.3.8.

Transmission Line Exclusions

Prior to next fire season, PG&E is evaluating all 552 transmission lines in the HFTD areas to determine which lines can be removed from future PSPS event scope via: supplemental inspections, below-grade inspections and repairs, increased VM (expand ROW), accelerated repairs or replacement of assets. Additional information can be found in Section 5.3.3.8.

Establishing PSPS Criteria for Hardened Distribution Facilities

PG&E plans to assess and develop decision making criteria for the potential exclusion of "safe-to-operate" hardened distribution facilities from PSPS de-energization during high fire threat weather conditions. Similar to PG&E's current risk-based transmission line assessment used during the event scoping process, distribution line criteria would be based on the wildfire risk reduction associated with the hardened assets. Additional information can be found in Section 5.3.3.8.

Microgrids for PSPS Mitigation

PG&E is proposing to pursue resiliency and reliability improvements to mitigate the customer impacts of PSPS through permanent and temporary front-of-the-meter microgrid solutions. Microgrids can reduce the number of customers de-energized during PSPS events, as well as provide additional impact mitigation by energizing shared community resources that support the surrounding population. Additional information can be found in Section 5.3.3.8.

Increased Model Granularity

PG&E weather modeling used for PSPS execution will increase weather and fuel model granularity from 3 km to 2 km. On-demand simulations will also be available at 0.67 km. Additional information can be found in Section 5.3.2.

PSPS Guidance Review

PSPS decision making guidance will continue to be assessed, including the evaluation of systematic incorporation of outputs from fire spread and consequence modeling and calibrating outage and FPI models with new data as it becomes available. Additional information can be found in Section 5.3.2.

Restoration Time

In 2019, PG&E's target was to restore service after a PSPS within 24 hours after the weather conditions clear. For 2020, PG&E is aiming for a 50% improvement in daylight restoration time, restoring power for 98% of customers within **12** daylight hours from the time the weather conditions clear. PG&E plans to increase aerial and ground resources and evaluate night patrol capabilities to reduce PSPS restoration time. Additional information can be found in Sections 5.3.6 and 5.3.9.

Backup Power Support for Societal Continuity

PG&E will continue to encourage customers to have a plan which may include backup power in the event of de-energization, and in exceptional cases, deploy backup generation support. Additional information can be found in Section 5.6.2.

Customer Services and Programs

PG&E will continue promoting and refining services and programs to customers that can assist in limiting the disruption of a PSPS-related outage before, during and after a PSPS event. These programs apply broadly to all types of customers and include providing the following: 24/7 information updates, experienced and knowledgeable business teams, continuous power programs, Community Resource Centers (CRCs), Third-Party Partnerships and Grant Programs, and coordination with Critical Facilities and Third-Party Commodity Suppliers. Additional information can be found in Section 5.6.2.

As a result of these initiatives and ongoing efforts, PG&E expects the PSPS program to evolve in the following ways in the 1-year, 3-year, and 10-year timeframe.

- In the 1-year timeframe, PG&E expects to see measurable reductions in the extent of PSPS impacts based on additional switching device installations, enhanced segmentation strategies, operationalized microgrid solutions, enhanced patrol and restoration approaches to reduce daylight restoration time, and other efforts described above to be implemented in 2020. PG&E expects customer programs and offerings continuing from 2019 and further refined in 2020 will provide ongoing mitigation of PSPS-related outage disruption. PG&E also expects to improve PSPS execution based on the after-action review lessons learned improvement workstreams identified in 2019, including more timely, accurate, and effective communication with customers and state, local, and tribal partners.
 - While initiatives are designed to reduce PSPS impact on a weather normalized basis, the absolute number and duration of customers impacted is largely weather event dependent in the 1-year timeframe.
- In the 3-year timeframe, PG&E expects to refine, evolve, and expand implementation of the opportunities identified above. PG&E expects to advance on longer-term efforts currently identified, such as behind-the-meter customer solutions and sectionalization. These ongoing efforts are expected to result in

fewer relative customers impacted in the 3-year timeframe beyond the reduction achieved in the 1-year timeframe.

- The absolute number and duration of customers impacted during the 3-year timeframe is unknown and will be dependent on the evolution of fuels, the amount of snow and rain received during the rain-season and number of high-risk weather events.
- In the 10-year timeframe, PG&E expects a significant reduction in PSPS impacts. In addition to ongoing PSPS program efforts, the long-term completion of PG&E's other wildfire mitigations described in this plan will create a more hardened system over time with the expected result of less extensive PSPS execution over time.
 - Although it is widely anticipated that average temperatures will increase over the next decade due to climate change in the 10-year timeframe, the number of offshore wind events and acute droughts that last one to several years is not certain. For example, a large and prolonged drought coupled with an increase in offshore wind events could necessitate more PSPS events in the future. In addition, urban expansion in the wildland urban interface, fuels treatment programs performed by state and federal agencies, changes in bark-beetle damage, tree mortality (e.g., sudden oak death), fuel loading, and general population growth are other external factors that may influence the scope of future PSPS events.

PG&E continues to recognize the commitment outlined in D.19-05-042 that while de-energization is a valuable tool to promote public safety, it must be deployed as a measure of last resort and the utility should continue to strengthen infrastructure to minimize the need for and size of de-energization events. However, it should be noted that mitigation activities such as system hardening and EVM are not expected to completely eliminate the use of PSPS in the interest of public safety if extreme conditions are forecasted. PSPS addresses a specific type of risk and, while other measures mentioned above help reduce the need to de-energize, PSPS remains a unique tool at the utility's disposal to help prevent catastrophic fire.

Protocols and Thresholds for PSPS implementation

See Section 5.6.2 Protocols on Public Safety Power Shutoff

Instructions for Table 20:

Rank order the characteristic of PSPS events (in terms of numbers of customers affected, frequency, scope, and duration) anticipated to change the most and have the greatest impact on reliability (be it to increase or decrease) over the next ten years. Rank in order from 1 to 9, where 1 means greatest anticipated change or impact and 9 means minimal change or impact on ignition probability and estimated wildfire consequence. To the right of the ranked magnitude of impact, indicate whether the impact is to significantly increase reliability, moderately increase reliability, have limited or no impact, moderately decrease reliability, or significantly decrease reliability. For each, include comments describing expected change and expected impact, using quantitative estimates wherever possible.

TABLE 20: ANTICIPATED CHARACTERISTICS OF PSPS USE OVER NEXT 10 YEARS

Rank order 1-9	PSPS characteristic	Significantly increase; increase; no change; decrease; significantly decrease	Comments
1	Duration of PSPS events in customer hours (normalized by fire weather, e.g., Red Flag Warning line mile days)	Significant Decrease	Directionally, there is the most opportunity to reduce customer hours per fire weather event through microgrids, segmentation, restoration time, and more granular weather forecasting in the short term, and system hardening and enhanced vegetation management in the long term. The absolute number and duration of customers impacted during this timeframe is unknown and dependent of numerous external factors.*
2	Scope of PSPS events in circuit-events, measured in number of events multiplied by number of circuits targeted for de- energization (normalized by fire weather, e.g., Red Flag Warning line mile days)	Significant Decrease	Proportionally, this is the next largest change, based on the reasons described above (1). While a significant reduction is expected, there still may be many circuits impacted, but much smaller portions of each circuit. The absolute number and duration of customers impacted during this timeframe is unknown and dependent of numerous external factors.*
3	Number of customers affected by PSPS events (normalized by fire weather, e.g., Red Flag Warning line mile days)	Significant Decrease	There should be a significant reduction in the number of customers impacted per fire weather event for the reasons described above (1) and (2), and due to the potential for "drop and pick-up" nature of micro-grids and resiliency zones, those customers will still be impacted, but for only a short duration during switching operations. The absolute number and duration of customers impacted during this timeframe is unknown and dependent of numerous external factors.*

TABLE 20: ANTICIPATED CHARACTERISTICS OF PSPS USE OVER NEXT 10 YEARS (CONTINUED)

Rank order 1-9	PSPS characteristic	Significantly increase; increase; no change; decrease; significantly decrease	Comments
4	Frequency of PSPS events in number of instances where utility operating protocol requires de-energization of a circuit or portion thereof to reduce ignition probability (normalized by fire weather, e.g., Red Flag Warning line mile days)	Potential decrease	A potential relative decrease in the frequency of events compared to all fire weather days or red flag warnings could occur as PSPS may not be required for marginal weather events based on reasons described above (1) and (2). However, changes in how red flag warnings are issued by the NWS may impact this evaluation as red flag warnings are not totally objective at this time. The absolute number and duration of customers impacted during this timeframe is unknown and dependent of numerous external factors.*
5	Duration of PSPS events in customer hours (total)	Potential Decrease	While an absolute decrease is expected in customer hours for the reasons described above (1), long term climate models point to higher probability of more frequent fire weather conditions. The absolute number and duration of customers impacted during this timeframe is unknown and dependent of numerous external factors.*
6	Scope of PSPS events in circuit-events, measured in number of events multiplied by number of circuits targeted for de-energization (total)	Potential Decrease	While an absolute decrease is expected in circuit events for the reasons described above (2), long term climate models point to higher probability of more frequent fire weather conditions. The absolute number and duration of customers impacted during this timeframe is unknown and dependent of numerous external factors.*
7	Number of customers affected by PSPS events (total)	Potential Decrease	While an absolute decrease is expected in the number of customers affected for the reasons described above (3), long term climate models point to a higher probability of more frequent fire weather conditions. The absolute number and duration of customers impacted during this timeframe is unknown and dependent of numerous external factors.*

TABLE 20: ANTICIPATED CHARACTERISTICS OF PSPS USE OVER NEXT 10 YEARS (CONTINUED)

Rank order 1-9	PSPS characteristic	Significantly increase; increase; no change; decrease; significantly decrease	Comments
8	Frequency of PSPS events in number of instances where utility operating protocol requires de-energization of a circuit or portion thereof to reduce ignition probability (total)	Possible Increase	Given that long term climate models point to a higher probability of more frequent fire weather conditions, it is expected that the absolute number of PSPS events may increase, while impacting fewer customers based on reasons described above (1) and (2). The absolute number and duration of customers impacted during this timeframe is unknown and dependent of numerous external factors.*
9	Other	N/A	N/A

Notes for Table 20:

1. *External factors include but are not limited: urban expansion in the wildland urban interface, fuels treatment programs performed by state and federal agencies, changes in bark-beetle tree damage and tree mortality (e.g., sudden oak death), fuel loading, general population changes, changes in regulatory requirements, climate change, droughts, frequency and duration of dry wind events.

PACIFIC GAS AND ELECTRIC COMPANY

2020 WILDFIRE MITIGATION PLAN

SECTION 5

**WILDFIRE MITIGATION STRATEGY AND PROGRAMS FOR
2019 AND FOR EACH YEAR OF THE 3-YEAR WMP TERM**

5 Wildfire Mitigation Strategy and Programs for 2019 and for Each Year of the 3-Year WMP Term Wildfire Mitigation Strategy

5.1 Wildfire Mitigation Strategy

Describe organization-wide wildfire mitigation strategy and goals for each of the following time periods:

1. *Before the upcoming wildfire season, as defined by the California Department of Forestry and Fire Protection (CAL FIRE),*
2. *Before the next annual update,*
3. *Within the next 3 years, and*
4. *Within the next 10 years.*

PG&E's approach to wildfire risk reduction, which has continued to evolve since the October 2017 North Bay wildfires and the 2018 Camp Fire, starts with the drivers of wildfire risk exposure (details are provided in Table 11 of Section 3.2). As seen in that data, contacts from vegetation and equipment failures are the largest drivers of historic ignitions, in the High Fire Threat District (HFTD) areas. Therefore PG&E's wildfire risk mitigation efforts have included, and will continue to include, vegetation management, inspections of electric distribution and transmission facilities, system hardening, and an improving Public Safety Power Shut-off (PSPS) program supported by situational awareness capabilities and PSPS mitigation activities. Informing all of these approaches has been PG&E's regular benchmarking with other utilities including within California and Australia, alongside engagement with academia, government agencies, technology providers and others. The understanding of climate change impacts to wildfire risk and potential solutions to mitigate that risk continues to evolve at a Global level, as we have unfortunately seen in Australia in the last several months.

In deploying wildfire risk mitigation efforts, which are focused on those drivers of wildfire risk exposures, PG&E continues to refine its understanding of geographic, meteorological and other considerations as to where the greatest wildfire risk exists. These efforts seek to optimize the deployment of wildfire mitigation activities to reduce the most risk as quickly as possible. To do so PG&E is attempting to incorporate all the latest information and best insights available. However, PG&E does not presume to be the expert on every topic or technology that may contribute to wildfire risk reduction. PG&E continues to look forward to engaging with those, including the parties to this proceeding, who may have insights, ideas or tools that can help further reduce wildfire risk and protect the customers and communities we serve. This 2020 Wildfire Mitigation Plan (WMP) is a snapshot in time and our plans will continuously improve towards our goal of preventing catastrophic wildfires caused by electrical equipment.

While the programs outlined in Section 5 represent PG&E's intended plans and targets, several programs presented here are subject to ongoing proceedings before the CPUC or other review or approval processes that may materially change PG&E's plans, requirements or guidelines within the WMP period or even before the upcoming wildfire season. Two key examples, though not the only initiatives subject to ongoing

proceedings are (1) efforts related to microgrids, which are subject to the Microgrid and Resilience Strategies Rulemaking (R.19-09-009) and (2) PSPS operations and customer support efforts, which are subject to outcomes of the Order Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions (R. 18-12-005). As these proceedings move forward PG&E's plans and activities may have to adjust relative to the plans presented in this 2020 WMP.

In the remainder of Section 5, PG&E describes in detail its wildfire mitigation strategies for this upcoming wildfire season, before the next annual update, within the next three years, and within the next 10 years. Note, however that evolution of the plan details is likely over the 3-year timeframe and certainly when considering the 10-year outlook as PG&E gains experience and additional data and information is developed. At a high level, PG&E's wildfire mitigation strategy and goals are focused on (1) reducing the potential for fires to be started by utility assets, (2) reducing the potential for fires to spread, and (3) minimizing the frequency, scope and duration of PSPS events. Highlights in working toward these goals will include:

Progress Timeline

1. Upcoming wildfire season:

- Continue to implement routine and enhanced vegetation management programs in order to reduce the risk of trees, limbs and branches coming into contact with power lines and equipment.
- Continue to identify and fix actual and potential equipment problems that could contribute to wildfire risk through the asset inspection, repair and replacement programs.
- Continue to harden the electrical distribution system by replacing or eliminating higher risk distribution lines and other assets in high-risk areas with equipment that is less likely to contribute to an ignition.
- Continue system automation and sectionalization upgrades that will allow PG&E to remotely control and operate field equipment to more precisely deenergize sections of the grid at times of high fire risk.
- Continue to improve understanding of weather and fire conditions through improved situational awareness and sophisticated meteorology operations in order to identify the highest-risk fire locations.
- Continue to improve the PSPS program through use of analytical and operational tools, tighter understanding of geographic fire risk and improving customer and community coordination and information sharing before, during and after outages. Focus on smarter, smaller and shorter PSPS events when weather conditions require the use of this tool.

2. Before the next annual update:

- Continue to implement the key wildfire mitigation programs and strategies described above – routine and enhanced vegetation management, asset

inspection and repair/replacement, system hardening, system automation, improved situational awareness and PSPS.

- Continue to modify wildfire mitigation programs by incorporating lessons learned throughout the 2020 wildfire season and in response to new regulations, requirements, guidelines or other changes.

3. Within three years:

- Continue to implement wildfire mitigation programs, including increased annual pace of system hardening deployment. Track and assess performance of implemented wildfire risk mitigation activities to validate effectiveness and inform program adjustments.
- Continue to drive PSPS events to be smarter, smaller and shorter based on further improved tools, processes and understanding of wildfire risk and weather patterns.
- Identify, evaluate and test new technology and tools to bolster operational capabilities, increase the flexibility of the grid and enable greater system resiliency. Develop and implement new wildfire mitigation programs using promising new technology and tools. (See Section 5.1D below for some of the technologies currently being explored.)

4. Within ten years:

- Track and assess performance of implemented wildfire risk mitigation activities over an extended period of time to validate effectiveness. Based on observed performance, continue using, modifying and improving elements of wildfire mitigation programs for as long as these measures are cost-effective in reducing the risk (frequency, scope and consequences) of wildfires, given the evolving threat of climate change in California.
- Incorporate improving research, information, data, technologies and other tools into wildfire risk reduction efforts including PSPS targeting and minimization activities.

5.1.A PG&E's Approach to Managing Wildfire Risk

A. Discuss the utility's approach to determining how to manage wildfire risk (in terms of ignition probability and estimated wildfire consequence) as distinct from managing risks to safety and/or reliability. Describe how this determination is made both for (1) the types of activities needed and (2) the extent of those activities needed to mitigate these two different groups of risks. Describe to what degree the activities needed to manage wildfire risk may be incremental to those needed to address safety and/or reliability risks.

When performing a risk analysis of a single, specific risk, like wildfire, PG&E focuses narrowly on the mitigations that benefit (reduce) that risk, either by reducing likelihood of an event or by reducing consequences of an event. Therefore, mitigations identified to reduce wildfire risk may or may not also benefit other risks that have safety and/or reliability impacts, such as asset failure. Each risk is assessed using a "bowtie analysis" (the wildfire risk bowtie analysis is provided in Section 4) with the mitigation activities that benefit a risk identified in those analyses. The risk bowtie analyses conform to requirements in the S-MAP settlement; risk bowties for risks that are deemed a RAMP risk will be presented in PG&E's 2020 RAMP Report, which will be submitted to the Commission in June.

A risk mitigation activity may appear in the bowtie analysis for more than one risk driver. This is often seen with wildfire risk reduction activities as tactics like vegetation management, bare conductor replacement (AKA system hardening) or equipment inspections and repairs benefit multiple risks with safety and reliability consequences beyond just wildfire. These activities and their RSE will be discussed in the appropriate risk bowtie analyses with the risk quantification (RSE) being exclusively focused on the risk being addressed in that analysis.

5.1.B Major Investments and Implementation of Wildfire Mitigation Initiatives

B. Include a summary of what major investments and implementation of wildfire mitigation initiatives achieved over the past year, any lessons learned, any changed circumstances for the 2020 WMP term (i.e., 2020-2022), and any corresponding adjustment in priorities for the upcoming plan term. Organize summaries of initiatives by the wildfire mitigation categories listed in Section 5.3

PG&E's Community Wildfire Safety Program (CWSP) is evolving rapidly as we gain experience on how various measures and technologies work to reduce the threat of catastrophic fires. A summary of the actions being taken to reduce wildfire risk and minimize PSPS event impact is provided below. The 2020 WMP activities, highlighted here, with additional detail provided in the relevant parts of Section 5.3, have evolved based on learnings to date, including the experience of the 2019 wildfire season. Based on what we learned from the 2019 PSPS events, PG&E is working to make any future PSPS events smaller in scope, shorter in duration and smarter in performance while working to keep customers and communities safe during times of severe weather and high wildfire risk. In addition to the PSPS impact reduction activities referenced below, including Microgrids, Temporary Generation and Distribution Sectionalization, PG&E is focused on improving support to impacted customers before and during PSPS events, as discussed in Section 5.6.2. Additionally, PG&E is making adjustments to mitigation programs based on the work conducted in 2019. With regard to the vegetation management program for 2020 and beyond, we are assessing the impacts of the 2019 EVM efforts to be sure that we use our resources most effectively in the years ahead; for instance, we plan to shift some EVM work from distribution to lower voltage transmission lines to expand rights-of-way and remove incompatible species, to reduce wildfire risk, and reduce the footprint of future PSPS events. In the case of asset inspections, PG&E's 2019 wildfire safety inspection program (WSIP) covered all 750,000 poles and structures in HFTDs and identified needed maintenance and replacement. Building on this foundation, PG&E is incorporating the enhanced inspection processes and tools into our routine inspection and maintenance program and will use risk-informed maintenance cycles in the years ahead—for instance, PG&E will initially conduct annual inspections of all facilities in HFTD Tier 3 areas and use three-year inspection cycles for Tier 2 facilities.

TABLE PG&E 5-1: MAJOR INVESTMENTS AND IMPLEMENTATION OF WILDFIRE MITIGATION – INITIATIVES CATEGORY

	Wildfire Mitigation Activity	2019 Actual Units	2019 Actual Spend (Preliminary)	2020 Targeted Units	2020 Target Spend	% Unit change	Notes
Situational Awareness and Forecasting	Weather Stations	426	\$6.9M	400	\$8.1M	-6%	
	HD Cameras	133	\$2.1M	200	\$3.5M	+50%	
Grid Design and System Hardening	System Hardening (line miles)	171	\$335M	221	\$367M	+41%	Butte County UG embedded in 2019 program, will be tracked separately in 2020
	Sys. Hard. (Butte County Underground Rebuild)			20	\$213M		
	Microgrids for PSPS mitigation (operationalized units)	1 (pilot Resilience Zone) + 3 temporary	\$3.3M	Additional operationalized units	\$11M	TBD	We intend to establish additional PSPS-mitigating microgrids and distributed generation resources in 2020. These Microgrid activities are subject to the ongoing regulatory approval processes.
	Distribution Sectionalization	298	\$50M	592	\$83M	+99%	

**TABLE PG&E 5-1: MAJOR INVESTMENTS AND IMPLEMENTATION OF WILDFIRE MITIGATION – INITIATIVES CATEGORY
(CONTINUED)**

	Wildfire Mitigation Activity	2019 Actual Units	2019 Actual Spend (Preliminary)	2020 Targeted Units	2020 Target Spend	% Unit change	Notes
Asset Management and Inspections	Transmission HFTD Enhanced Inspections (structures)	49,715 ¹	\$68M	~22,000	\$46M	-56%	There is no separate WSIP in 2020, the program is shifting to risk/tier-based inspection cycles, primarily Tier 3 assets inspected annually and Tier 2 assets inspected on a 3-year cycle
	Distribution HFTD Enhanced Inspections (poles)	694,250	\$160M	~344,000	\$88M	-50%	
	Substation HFTD Enhanced Inspections	222	\$22M	~105	\$16M	-53%	
Vegetation Management and Inspection	Enhanced Vegetation Management (line miles)	2,498	\$443M	1,800	\$495M	-28%	Some resources will be redeployed from EVM to targeted fuels reduction and T-Line 60/70 kV right-of-way clearance work

¹ Some (~10,000) transmission enhanced visual inspections were completed in late 2018 but are included in this count to reflect the completion of a dedicated program (the Wildfire Safety Inspection Program) to inspect all assets in HFTD Tier 2 & Tier 3 areas.

5.1.C Challenges Associated With Limited Resources

C. List and describe all challenges associated with limited resources and how these challenges are expected to evolve over the next 3 years.

As discussed in Section 5.5, limited resources are a significant, but far from the only, execution risk facing WMP implementation. PG&E learned a number of lessons from the execution of the 2019 WMP including the challenge created by a significant peak of work to be performed over a limited window of time and the limited ability to scale up skilled resources to support such a peak in a short amount of time. PG&E has incorporated a number of changes into its work planning for wildfire mitigation activities for 2020 and beyond. Nonetheless, resource limitations may still be a challenge in a few key areas, including Vegetation Management where the volume of work remains high, the hazards inherent in that work remain significant (requiring skilled and experienced resources to be carefully sourced) and evolving regulations (including Senate Bill 247 passed in 2019) may influence changes in the available California resources, both in terms of vegetation management companies and their employees. Given the rapid evolution in this space in the last twelve months, it is difficult to forecast how the labor market and resource capacity/availability within California will change over the next three years. However, PG&E appreciates that getting more talented individuals into the field now and moving these individuals up the learning and training curve, is likely a universal benefit. Therefore, PG&E has kicked off efforts, including with community colleges and in partnership with the IBEW, to establish training programs to increase the size of the skilled workforce.

The vegetation management, line worker and other labor markets will continue to evolve over the next three years. To meet resource challenges, PG&E's operations, human resources, and sourcing teams will continue to partner closely to identify solutions to match available, qualified, and safe resources with the critical wildfire risk mitigation work that needs to be completed.

5.1.D New or Emerging Technologies

D. Outline how the utility expects new technologies and innovations to impact the utility's strategy and implementation approach over the next 3 years, including the utility's program for integrating new technologies into the utility's grid.

5.1.D.1 Impact on Strategies

PG&E continues to actively explore technologies that can mitigate ignition risk and associated potential impact on public safety. Section 5.1.D details mitigations that are currently being pursued and use new or emerging technologies consistent with the following definitions:

- New: Technologies or analytical methods enabled through technology that were new to PG&E after the release of its 2019 WMP (*i.e.*, February 6, 2019), exclusive of 'emerging' technologies
- Emerging: Pre-commercial technologies, including Technology Demonstration & Deployment projects²

These technologies hold significant promise to advance PG&E's wildfire risk mitigation, bolster operational capabilities, increase the flexibility of the grid, and allow for greater system resiliency. Capabilities targeted through new or emerging technologies include, but are not limited to:

- Situational awareness and forecasting: New or emerging technologies can enable more accurate forecasting and identification of environmental events and operating conditions that pose a risk to the grid so that critical issues may be dealt with as quickly as possible to avoid the risk of catastrophic wildfires.
- Grid design and hardening: New or emerging technologies can enable innovative system hardening techniques to mitigate the risk of fire ignition and potential impacts on public safety.
- Asset management and inspections: New or emerging technologies can enable automated and improved methods to identify asset or system issues so that high risk items can be addressed prior to failure.
- Vegetation management and inspections: New or emerging technologies can enable more timely and accurate insights on vegetation health, density and proximity to assets allowing PG&E to implement risk-based vegetation management work practices to further ensure high risk areas are efficiently addressed.
- Asset Analytics and Grid Monitoring: New or emerging technologies can leverage data to enable greater insights on asset health to optimize system maintenance and reduce the risk of asset failure.

² The Technology Demonstration and Deployment (TD&D) demonstration project definition was approved by the CPUC in D-12-05-037: "The installation and operation of pre-commercial technologies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments, to enable the financial community to effectively appraise the operational and performance characteristics of a given technology and the financial risks it presents."

- Foundational Enablement: New or emerging technologies, including grid communication tools and control networks, can enable greater exchange of information required to provide real or near-real time operational visibility across the grid for enhanced decision-making. These foundational items can also increase the flexibility of the grid, providing fundamental capabilities to advance system resiliency.

The impacts of new or emerging technologies on utility strategy will vary by project. Information on the strategic enablement of these technologies is detailed further in Sections 5.1.D.2 and 5.1.D.3 below. The scope and implementation of these projects are subject to change due to the evolving nature of technology and business needs. There will likely be technologies that develop or mature over the reporting timeframe (2020-2022) which PG&E may pursue that are not described in Section 5.1.D.3.

5.1.D.2 Implementation Approach and Integration of Emerging Technologies – Electric Program Investment Charge

The Electric Program Investment Charge (EPIC) portfolio provides PG&E with an opportunity to demonstrate the value of emerging technologies that hold promise in furthering system resiliency. Through EPIC, PG&E develops and demonstrates innovative technologies that advance a broad array of objectives including grid safety, resiliency and reliability as well as customer enablement, and integration of renewable and DERs. PG&E implements project governance over its EPIC demonstration projects to ensure a clear path to production if the technology is proven ready to scale. Various criteria are assessed that may impact a technology's successful implementation, including the following: (i) project hypothesis; (ii) dependencies or alternatives; (iii) obstacles to implementation; (iv) project success metrics at demonstration and full deployment stages (v) potential benefits at full deployment. PG&E assesses alignment to utility strategies and customer needs to help ensure that project deliverables provide a pathway towards improvements and enables PG&E (and potentially other utilities) to better serve its customers and deliver on program objectives, including enhancements to safety and grid resiliency.

EPIC demonstrations aid in identifying key requirements and insights to inform full deployment in a manner that strategically aligns the integration of technologies with existing operations. Given the rapidly evolving energy landscape and the impact of climate change in California, the continuation of technology innovation programs like EPIC is critical to the continued advancements of grid capabilities to enable advancements on safety and resiliency.

5.1.D.3 New or Emerging Technologies – Project Summaries

This section provides an overview of select mitigations that leverage new or emerging technologies. These projects are summarized in the table below.

TABLE – 5.1.D.3: SELECT NEW OR EMERGING TECHNOLOGIES

Section	Title	Program Area	Wildfire Mitigation Maturity Assessment - Primary Category Impacted	Approximate 2020 Financial (\$K) Forecast ³
5.1.D.3.1	Wildfire Spread Models	Situational Awareness & Forecasting	A. Risk mapping and simulation	\$3,300
5.1.D.3.2	Satellite Fire Detection	Situational Awareness & Forecasting	B. Situational awareness and forecasting	\$500
5.1.D.3.3	Weather Model and Fire Potential Index - Model Expansions	Situational Awareness & Forecasting	B. Situational awareness and forecasting	\$1,500
5.1.D.3.4	SmartMeter™ Partial Voltage Detection (formerly known as Enhanced Wires Down Detection)	Situational Awareness & Forecasting	C. Grid design and system hardening	\$900
5.1.D.3.5	Line Sensor Devices	Situational Awareness & Forecasting	C. Grid design and system hardening	\$6,900
5.1.D.3.6	Proactive Wires Down Mitigation Demonstration Project (Rapid Earth Fault Current Limiter)	Grid Design & System Hardening	C. Grid design and system hardening	\$8,900

³ Financial forecasts for emerging technology assessment or deployment projects are highly tentative as uncertainty regarding costs and functionality is very high for new technologies. Costs shown reflect estimates as of late January 2020 and are subject to change, including several that remain TBD at this time. Costs beyond 2020 have not yet been defined given this level of uncertainty.

**TABLE – 5.1.D.3: SELECT NEW OR EMERGING TECHNOLOGIES
(CONTINUED)**

Section	Title	Program Area	Wildfire Mitigation Maturity Assessment - Primary Category Impacted	Approximate 2020 Financial (\$K) Forecast ³
5.1.D.3.7	Distribution, Transmission, and Substation: Fire Action Schemes and Technology (DTS-FAST)	Grid Design & System Hardening	C. Grid design and system hardening	\$10,500
5.1.D.3.8	Remote Grid	Grid Design & System Hardening	C. Grid design and system hardening	\$943
5.1.D.3.9	Multi-Use Microgrid	Grid Design & System Hardening	C. Grid design and system hardening	\$664
5.1.D.3.10	Enhanced Asset Inspections - Drone/AI (Sherlock & Waldo)	Asset Management and Inspections	D. Asset Management and Inspections	\$6,900
5.1.D.3.11	Ultrasonic Technology	Asset Management and Inspections	D. Asset Management and Inspections	TBD
5.1.D.3.12	Below Ground Inspection of Steel Structures	Asset Management and Inspections	D. Asset Management and Inspections	TBD
5.1.D.3.13	Mobile LIDAR for Distribution Inspections	Vegetation Management and Inspections	E. Vegetation management and inspections	TBD
5.1.D.3.14	Transformer Monitoring via Field Area Network (FAN)	Asset Analytics & Grid Monitoring	C. Grid design and system hardening	\$443
5.1.D.3.15	Maintenance Analytics	Other - Asset Analytics & Grid Monitoring	C. Grid design and system hardening	\$989
5.1.D.3.16	System Harmonics for Power Quality Investigation	Other - Asset Analytics & Grid Monitoring	C. Grid design and system hardening	\$653
5.1.D.3.17	Sensor IQ	Other - Asset Analytics & Grid Monitoring	C. Grid design and system hardening	\$1,339
5.1.D.3.18	Wind Loading Assessments	Other - Asset Analytics & Grid Monitoring	C. Grid design and system hardening	\$3,405

TABLE – 5.1.D.3: SELECT NEW OR EMERGING TECHNOLOGIES
(CONTINUED)

Section	Title	Program Area	Wildfire Mitigation Maturity Assessment + Primary Category Impacted	Approximate 2020 Financial (\$K) Forecast ³
5.1.D.3.19	Predictive Risk Identification with Radio Frequency (RF) Added to Line Sensors (Distribution Fault Anticipation Technology)	Other - Asset Analytics & Grid Monitoring	C. Grid design and system hardening	\$1,126
5.1.D.3.20	Advanced Distribution Energy Resource Management System	Foundational	Not Applicable	\$2,318
5.1.D.3.21	Advanced Distribution Management System (ADMS)	Foundational	Not Applicable	\$1,500

The descriptions below are divided by program areas.

Program Area: Situational Awareness and Forecasting – New and Emerging Technologies

PG&E is deploying a powerful set of complementary tools to better assess and more accurately locate, often in near real time, environmental events that pose a danger to the grid so that critical issues may be dealt with as quickly as possible to avoid the risk of catastrophic wildfires. In addition, PG&E is exploring the use of situational awareness technologies that provide insights on grid conditions. Below are mitigations leveraging new or emerging technologies – for additional information, reference Section 5.3.2.

5.1.D.3.1 Wildfire Spread Models

Type: New Technology (Commercially Available Offering)

Description: This project is described in Section 5.3.2.1.3: Situational Awareness & Forecasting – Wildfire Spread Models

5.1.D.3.2 Satellite Fire Detection

Type: New Technology (Commercially Available Offering)

Description: This project is described in Section 5.3.2.1: Situational Awareness & Forecasting – Advanced Weather Monitoring and Weather Stations

5.1.D.3.3 Weather Model and Fire Potential Index – 2019 Model Expansions

Type: New Technology (Commercially Available Offering)

Description: This project is described in Section 5.3.2: Situational Awareness & Forecasting – Forecast of a fire risk index, fire potential index, or similar

5.1.D.3.4 SmartMeter™ Partial Voltage Detection (Formerly Known as Enhanced Wires Down Detection)

Type: Emerging (Pre-commercial) Technology

Description: This project is described in Section 5.3.2: Situational awareness and forecasting - SmartMeter™ Partial Voltage Detection (Formerly Known as Enhanced Wires Down Detection)

5.1.D.3.5 Line Sensor Devices

Type: New Technology (Commercially Available Offering)

Description: This project is described in Section 5.3.2: Situational Awareness & Forecasting – Line Sensor Devices

Program Area: Grid Design and System Hardening – New and Emerging Technologies

PG&E is reducing the risk of fire ignition and potential impacts on public safety through the adoption of system hardening methods enabled through innovative technologies. Mitigations leveraging new or emerging technologies include the following:

5.1.D.3.6 Proactive Wires Down Mitigation Demonstration Project

Type: Emerging (Pre-commercial) Technology

Description: The EPIC 3.15, Proactive Wires Down Mitigation demonstration project, seeks the ability to automatically and rapidly reduce the flow of current and risk of ignition in single phase to ground faults through the use of Rapid Earth Fault Current Limiter (REFCL). The REFCL Technology has been shown by the Victoria State Government (Australia) to directly reduce the risk of wildfires for single line to ground faults.⁴ REFCL works by moving the neutral line to the faulted phase during a fault, which significantly reduces the energy available for the fault. This significantly lowers the energy for single line to ground faults by reducing the potential for arcing and fire ignitions, as well as better detection of high impedance faults / wire on ground. REFCL technology is only feasible for three-wire uni-grounded circuits, which make up the majority of PG&E's distribution circuits within high fire threat areas. Successful implementation of REFCL technology has potential to more reliably detect high impedance ground faults and energized wire down events and minimize this risk to public safety. PG&E began planning the project in early 2019; demonstrations are planned to begin in 2020 on operational assets to test its capabilities and applications within PG&E's system.

⁴ Marxen Consulting / Victoria State Government. "REFCL Trial: Ignition Tests." 4 August 2014. Accessible at: <https://www.energy.vic.gov.au/safety-and-emergencies/powerline-bushfire-safety-program/network-assets-program/rapid-earth-fault-current-limiter-refcl>.

5.1.D.3.7 Distribution, Transmission, and Substation – Fire Action Schemes and Technology (DTS-FAST)

Type: Emerging (Pre-commercial) Technology

Description: The Distribution Transmission Substation—Fire Action Scheme and Technology (DTS-FAST) system is designed to reduce fire risks associated with energized power lines. DTS-FAST was developed internally at PG&E and is currently in pilot phase. This technology aims to use fraction-of-a-second technologies to detect objects approaching energized power lines and responds quickly to shut off power, before object impact. In addition, DTS-FAST may detect elevated fire risk conditions associated with energized power lines, quickly shutting off power when such risks occur, including:

1. Downed Power lines
2. Downed and leaning towers and poles
3. Jumper cable and insulator hook failures
4. Vegetation encroachment and vegetation optimization
5. Fire and smoke detection at towers or poles
6. Power line sag
7. Hot spot detection from tower to tower

This technology could allow PG&E to reduce PSPS events and expedite restoration times. It could also provide PG&E the ability to pin point the location of potential fire risks. If proven, scaling this technology across PG&E's system will be complex, but offers significant benefits as detailed above.

5.1.D.3.8 Remote Grid

Type: New Technology (Commercially Available Offering)

Description: Remote Grid is a new utility service concept using decentralized energy sources for permanent energy supply to remote customers as an alternative to energy supply through hardened traditional utility infrastructure. Throughout PG&E's service territory, there are pockets of isolated small customer loads that are currently served via long electric distribution feeders, or until recently have been served by such feeders (but are now disconnected due to damage from recent wildfires). In many circumstances, these feeders traverse through HFTDs areas. If these long feeders were removed and the customers served from a local and decentralized energy source, the resulting reduction in overhead lines could reduce fire ignition risk as an alternative to or in conjunction with system hardening. In addition to reducing wildfire risk, Remote Grid could be a cost-effective solution against expense and capital costs for the rebuild of fire-damaged infrastructure or for HFTD hardening infrastructure jobs to meet new HFTD build standards.

PG&E's Remote Grid Initiative will validate and develop Remote Grid solutions as standard offerings such that they can be considered alongside or in lieu of other service arrangements and/or wildfire risk mitigation activities such as system hardening. In 2020, PG&E plans to deploy at least 4-8 initial sites to validate use cases, design standards, deployment processes and commercial arrangements. Based on the results of the initial projects, PG&E will deliver recommendations for scale up and/or further development for consideration in 2021 and beyond.

5.1.D.3.9 Multi-Use Microgrid

Type: Emerging (Pre-commercial) Technology

Description: The EPIC 3.11, Multi-use Microgrid demonstration project, seeks to enable a multi-customer microgrid within the Arcata-Eureka Airport business community and will incorporate four PG&E and Redwood Coast Energy Authority customers. The project will design and develop control specifications and provide SCADA integration to maintain visibility and operational control of the microgrid in grid-connected and islanded modes. This project will test capabilities to integrate third party controlled microgrids into PG&E's distribution system. The findings of this project will help support microgrid growth to support resiliency (e.g., remote grid configurations) and enhanced customer choice.

Program Area: Asset Management and Inspections – New and Emerging Technologies

PG&E is developing new inspection tools and methods to quickly identify issues and proactively manage asset and system maintenance. This in turn reduces the risk of asset failure and potential impacts on our customers. PG&E is leveraging existing technologies, including remote sensing technologies such as LIDAR data and drone imagery capture,⁵ to accurately identify risks, including encroachment clearance and vegetation health. Combined with machine learning software, remote sensing data are being evaluated to identify dead or dying trees that could pose wildfire hazards or contribute to a wires-down situation. Mitigations leveraging new or untested technologies include the following:

5 Future drone technology adoptions are dependent upon FAA regulations for Line of Sight requirements. If exceptions are granted to these requirements, PG&E will have the opportunity to consider new or untested drone technology use cases such as: (i) extended line of sight operations for greater crew efficiency; (ii) autonomous flight paths to expedite drone inspections; (iii) new charging methods that leverage existing asset infrastructure to minimize charging time and increase flight time.; and (iv) new data processing techniques that minimize data hand off processes by capturing and processing data in-air, allowing for greater in-air operation.

5.1.D.3.10 Enhanced Asset Inspections – Drone/AI (Sherlock & Waldo)

Type: New Technology (Not Widely Commercialized)

Description: Sherlock is a web application that allows inspectors to view and inspect photographs of assets along with associated data. It also allows for pre-inspection review of data coming in from drone pilots, helicopter photographers, and other means of data capture, to ensure that only quality-assured data is viewed by inspectors, and further by others such as engineers, estimators and investigators who need the photos for their work. In addition, inspectors can file corrective requests within the Sherlock application itself by marking up photographs and selecting the appropriate failure and severity rating of identified issues. Sherlock is designed in a flexible manner such that remote inspections of transmission, distribution, substation, and any other asset can be performed via the application.

The corrective requests identified by inspectors inside Sherlock feed Waldo, a computer vision API (Application Programming Interface), where computer vision models are trained to identify issues using Artificial Intelligence (AI), in an automated fashion. Waldo’s predictions can then be surfaced in Sherlock to be confirmed as correct or incorrect by inspectors, creating a positive feedback loop which then improves the models further. Other applications (e.g., mobile applications) can send/receive data and images to/from Waldo to train/retrain models, and/or to receive predictions to help automate their processes.

Additionally, Sherlock also has a search feature which allows access to organized images and other asset data, with a map to show the location of the photos in relation to the asset, and the ability to view photos of an asset by date taken. This allows for visibility into a historical view of the asset, expanded understanding of the specific asset location, increased visibility into data quality, and ease of access to asset information with a simple search.

Future features in Sherlock may allow for automated tracking of flights and inspections, inspector bias detection, automated inspection and photo quality checks, inspector performance measurement, enhanced pre-inspection quality assurance, easy upload and verification of photographs by field workers, search by AI-provided metadata (e.g., search for “porcelain insulators” will return photos of assets with porcelain insulators), and AI-assisted asset inventory.

5.1.D.3.11 Ultrasonic Technology

Type: New Technology (Commercially Available Offering)

Description: This project is described in Section 5.3.4, Asset Management and Inspections – Initiative: ‘Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations’

5.1.D.3.12 Below Ground Inspection of Steel Structures

Type: New Technology (Commercially Available Offering)

Description: PG&E is assessing broader use of below ground inspection of steel structures, to evaluate structural and environmental corrosion of foundations, and design mitigation and restoration solutions to ensure transmission structure resilience. PG&E piloted this solution in 2015 (Sobranite Station) and 2017 (Moraga-Oakland Line) in conjunction with reconductoring transmission circuits. PG&E is assessing a follow up pilot that will regularly inspect steel assets below groundline to detect steel corrosion and concrete degradation that may compromise structural integrity, with the goal of reducing risk of steel assets in the transmission plant and substations. Foundation degradation of steel structures has the potential to introduce risk - this is especially true with older structures. To inspect below ground, the foundations/footings of steel towers and poles are excavated and evaluated for structural integrity, including measuring steel member material section loss, and collecting environmental and soil data (soil resistivity, pH, structure to soil potential/VDC, REDOX). Repairs and mitigations are prioritized, based on the field evaluations and soil samples, in combination with other evaluations of tower/structure and overhead assets. Advanced analytics can also be applied to the data, helping to inform a risk ranking of structures. Foundations that don't require repair or mitigation are treated with an engineered coating system to extend the life of the asset.

Program Area: Vegetation Management and Inspections – New and Emerging Technologies

PG&E is using a variety of technologies to enable vegetation related insights. For instance, physical ground inspections are being augmented by the capture of LiDAR and related, remote sensing, data that can be thoroughly and consistently analyzed to take measurements, reveal patterns and identify risks. Vegetation Management has benefited from better intelligence of vegetation density and can leverage this data to strategically deploy resources where vegetation is near the electrical assets. Mitigations leveraging new or emerging technologies include the following:

5.1.D.3.13 Mobile LiDAR for Distribution Inspections

Type: New Technology (Commercially Available Offering)

Description: In 2019, PG&E began collecting LiDAR point cloud and high-resolution data in areas of interest with CycloMedia technology mounted to vehicles and off road systems. Throughout 2019, up to 8 vehicles were deployed to collect (or scan) accurate and dense LiDAR point cloud and high resolution GeoCycloramas (high resolution 360-degree panoramic spherical street-level images) with CycloMedia technology. To allow PG&E to collect the data it needs for analysis, each CycloMedia system is carefully calibrated. The well-trained collection team performs quality assurance checks in the field during favorable weather conditions to help ensure optimal imagery and LiDAR is being collected. Mobile scanning tools may have the ability to consistently and repeatedly inspect miles of right-of-way. The measured results and imagery provide date-stamped documentation and a record for the basis of action and confirmation of completed actions.

Program Area: Other – Asset Analytics & Grid Monitoring – New and Emerging Technologies

PG&E is assessing new methods to optimize asset maintenance practices. Unanticipated failure of electric assets due to wear and tear can lead to customer service outages and, in the worst case, fire ignition. Proactive management of asset health can reduce this risk and enhance system resiliency. PG&E is researching new or emerging technologies, such as enhanced sensor technologies that enable real-time system monitoring and situational awareness and developing analytic strategies to coordinate data received from multiple sources (e.g., SCADA, SmartMeter™, primary line sensors, and emerging sensor technologies). Mitigations leveraging new or emerging technologies include the following:

5.1.D.3.14 Transformer Monitoring

Type: Emerging (Pre-commercial) Technology

Description: The EPIC 3.13, Transformer Monitoring via Field Area Network demonstration project, seeks to expand its methods for transformer monitoring by developing an accurate, automated and data-driven method for identifying transformer temperature and the associated risk of asset failure that could impact safety and resiliency. As transformers reach the end of their usable life or overload, they begin to heat up, leading to potential safety and asset risks. Currently, identification of transformer temperature change and potential risk poses challenges and requires regular checks from PG&E field teams. This demonstration project aims to increase the visibility of transformer health through the design and build of an overhead transformer temperature sensor, supplemented by analytical models that analyze temperature data. Sensor data will be communicated to PG&E's Distribution Management System. PG&E will prioritize the roll-out of this technology by developing criteria to identify the highest risk locations on the distribution grid for sensor installation. The data provided by the sensors will enable PG&E to optimize transformer maintenance practices, reducing the risk of transformer failure to mitigate potential impacts to safety and grid resiliency.

5.1.D.3.15 Maintenance Analytics

Type: Emerging (Pre-commercial) Technology

Description: The EPIC 3.20, Maintenance Analytics, demonstration project aims to reduce unanticipated distribution asset failures through the development of predictive maintenance capabilities. The project will monitor for signs of failure onset through use of existing data sources including SmartMeter™ connectivity data, geolocational asset data, and weather data. The objective is to develop an analytical model in conjunction with existing PG&E data sets to predictively identify electric distribution equipment issues so that corrective action can be taken before failure occurs.

5.1.D.3.16 System Harmonics for Power Quality Investigation

Type: Emerging (Pre-commercial) Technology

Description: The EPIC 3.32, System Harmonics for Power Quality Investigation demonstration project, seeks to explore the use of next generation metering technology harmonics data to help automate the investigation and resolution of harmonics issues. Excessive harmonics have been shown to reduce utility equipment life, can cause premature equipment failure due to the potential to overheat, and can interfere with the operation of protection devices. Harmonics data from next generation metering technology can enable power quality engineers to monitor harmonics levels on the circuits and proactively address harmonics issues before they create a negative impact on PG&E and customers' equipment, mitigating the chances of equipment failure to have adverse effects or safety impacts.

5.1.D.3.17 Sensor IQ

Type: New Technology (Commercially Available Offering)

Description: Itron/SSN is being contracted to implement Sensor IQ, which allows for a parallel, more granular data path (outside of billing) to support distribution asset analytics use cases. Deployment enables customizable Network Interface Card (NIC) data sampling, read jobs, and alarms. The scope includes implementing Sensor IQ to all SmartMeters in HFTD areas and customizing reads and alarms to identify service transformer failures, with other use cases to be considered based on wildfire risk reduction and/or business value. The data collected through Sensor IQ is critical for a variety of other wildfire related initiatives, including: (i) Rapid Earth Fault Current Limiter which requires feeder phasing to determine the line-earth capacitive imbalance; and (ii) increasing the data collected (voltage, current, power factor) and increasing the frequency of data collection will improve wires down algorithms to find faults.

5.1.D.3.185.1.D.3.17 Wind Loading Assessments

Type: Emerging (Pre-commercial) Technology

Description: This project will reduce risk by providing asset intelligence to identify locations that require corrective actions driven by pole safety factors or limitations for wind speeds. The project will leverage existing LiDAR data from Vegetation Management efforts to geo-correct pole locations. Objectives of this project include a greater understanding of failure modes, establishment of a common repository of data gathered, and effectively updating workflows of key asset systems to align with new data strategies. Wind loading segmentation will be performed to identify the wind loading of each asset on a support structure and integrate findings into appropriate systems.

5.1.D.3.195.1.D.3.18 Predictive Risk Identification With Radio Frequency (RF) Added to Line Sensors (Distribution Fault Anticipation Technology)

Type: Emerging (Pre-commercial) Technology

Description: This project is described in Section 5.3.2, Situational Awareness and Forecasting. Technologies demonstrated through this project are summarized through the references to 'Distribution Fault Anticipation Technology' and 'Early Fault Detection.'

Program Area: Other – Alternative Technologies – Foundational Technology

PG&E continues to deploy foundational technologies that enable grid communication, including sensors, metering, maintenance, and grid asset control networks to allow the exchange of information required to provide real or near-real time operational visibility across the grid. For instance, PG&E will continue to develop Network SCADA monitoring capabilities to help monitor voltages, currents, temperature, transformer oil level, and chamber pressures. This data can trigger alarms or be used for equipment condition assessment as part of the Condition-Based Maintenance (CBM) system for O&M activities. The data is used for asset management decisions on the maintenance and replacement of network equipment. Mitigations leveraging new or emerging technologies include the following:

5.1.D.3.205.1.D.3.19 Advanced Distribution Energy Resource Management System

Type: Emerging (Pre-commercial) Technology

Description: The EPIC 3.03, Advanced Distribution Energy Resource Management System demonstration project, seeks to design, procure, and deploy a prototype enterprise DER Management System. This includes development of a cost-effective non-SCADA solution for providing advanced situational awareness and control capabilities. This project is a key component of a multi-year effort to implement a full scale DER Management System. This system, if implemented, may enable operators to better manage DERs, dispatch DER Registration data requests and monitor Smart Inverter (SI)-based DERs through a head-end platform, and provide an interface to dispatch DERs as remote grid and Non-Wires Alternative (NWA) solutions. A DER Management System could become part of the core distribution operations technology tools that enable visibility, control, forecasting and analysis of a more dynamic grid.

5.1.D.3.245.1.D.3.20 Advanced Distribution Management System (ADMS)

Type: New Technology (Commercially Available Offering)

Description: PG&E is undertaking the first component of a multi-year effort⁶ to implement an Advanced Distribution Management System (ADMS), which will integrate several mission critical distribution control center applications that are currently spread across multiple platforms. The ADMS will become part of the core distribution operations technology tools that enable the visibility, control, forecasting, and analysis of a more dynamic grid. When fully deployed, the ADMS platform will bring the capabilities of today's Distribution Supervisory, Control and Data Acquisition (D-SCADA) software, Demand Management System (DMS), and Outage Management System (OMS) into a single platform. Integrating these systems into a single, more efficient platform will reduce the potential for operator error, improve cybersecurity risk controls, and enable PG&E to run a new suite of advanced applications that enhance current capabilities associated with safety and resiliency, while responding to future needs associated with the growth of DERs and complexities from wildfire risk. Below are examples of the methods in which ADMS may impact grid resiliency:

- **Distributed Energy Resource Integration:** ADMS will enable distributed energy resource integrations which may be prevalent with future microgrid configurations towards enhanced resiliency.
- **Switching Operations:** Longer term, as additional functionalities are built out, ADMS can improve PG&E's ability to sectionalize the grid during a Public Safety Power Shutoff (PSPS) by providing more timely and accurate data to operators, allowing them to optimize switching operations and minimize associated outage impacts on customers.
- **Reclosing Relay Disablement:** Currently, distribution operators have the ability to block reclosing relays within fire index area zones when weather and conditions pose significant risk to the system. Doing so adds an additional layer of protection against ignition risk. This process requires SCADA technicians to redesign individual scripts to manually transition devices to their new settings. New tools enabled through ADMS hold the potential to automate this process by having ADMS identify the devices within the designated fire areas and present the potentially impacted areas to the operators for verification. This automation utilizes more accurate as switched conditions thereby decreasing the opportunity for failed commands. When commands are failed, ADMS may be able to flag issues, providing greater operator situational awareness.

⁶ ADMS developments and implementation will expand beyond the 2020-2022 timeline covered by the 2020 WMP.

Program Area: Other – Alternative Technologies – Electric Portfolio Investment Charge, Investment Plan⁷

EPIC plays a key role in the advancement of grid capabilities to enhance or enable safety, resiliency, and renewable and DER integration. PG&E is excited to embark on new technology demonstrations which build on past projects, meet emerging grid needs and California policy objectives, and ensure that customers and the state can maximize the benefits of this program. Below are select demonstration projects that PG&E may pursue (subject to funding approvals and EPIC 3 Wave 2 planning) that represent mitigations leveraging emerging technologies:

- EPIC 3.21: Advanced Vegetation Management Insights Using Prescriptive Analytics – This project will seek to demonstrate a prescriptive analytics model that predicts tree growth rates and areas at highest risk for vegetation-related outages by leveraging LiDAR, other remote sensing data, and historical vegetation-based outages for proactive and targeted mitigation. The model could be used for routine maintenance activities, reliability-focused project planning, or planning and staging – maturing the use of LiDAR data to inform operational practices.
- EPIC 3.41: Drone Enablement and Operational Use – This project will seek to develop and demonstrate a foundational utility-focused Drone enablement systems and initial use cases to form the foundation for future utility Drone operations. Several potential use cases will be explored leveraging the foundational technologies for management and operation of the drones. The use cases enabled through this project will depend on FAA regulations for Line of Sight requirements and potential for exceptions to existing regulations. Example use cases include: (i) extended line of sight operations for greater crew efficiency; (ii) autonomous flight paths to expedite drone inspections; (iii) new charging methods that leverage existing asset infrastructure to minimize charging time and increase flight time; and (iv) new data processing techniques that minimize data hand off processes by capturing and processing data in-air, allowing for greater in-air operation.

⁷ Application of Pacific Gas and Electric Company (U 39 E) for Approval of Its 2018-2020 Electric Program Investment Charge Investment Plan, A.17-04-028, Dated April 28, 2017. <https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/EPIC-3-Application-PGE.pdf>.

5.2 Wildfire Mitigation Plan Implementation

5.2.A Monitor and Audit WMP Implementation

A. Monitor and audit the implementation of the plan. Include what is being audited, who conducts the audits, what type of data is being collected, and how the data undergoes quality assurance and quality control.

PG&E has developed plans and processes to monitor and regularly audit the 2020 WMP as it is being implemented. The effort to monitor and audit elements of the 2020 WMP is supported by the WMP implementation teams, the WMP Program Management Office (PMO) and PG&E's Internal Audit (IA) organization. PG&E has developed programmatic quality and monitoring processes and protocols for individual programs within the WMP. The individual quality monitoring processes for WMP program elements are described in Section 5.3, Detailed Wildfire Mitigation Programs, Sections 5.3.1 through 5.3.10.

PG&E's WMP PMO is responsible for monitoring the progress of the individual WMP workstreams and the quality of the WMP work at the program level. The PMO provides progress tracking and status updates via a weekly dashboard. The PMO also provides both a monthly update and a comprehensive quarterly WMP report. The PMO provides on-going oversight and direction to the WMP program leaders. In addition, the status and tracking reports provide PG&E leadership, and ultimately the board of directors, visibility into the different elements of the WMP and gives them the information they need to monitor and, when needed, make adjustments to the program. See Attachment 1, Table 23 for the details and data associated with the WMP PMO.

At the individual WMP program level, PG&E has developed quality monitoring and audit plans tailored to each program. For example, the WMP quality monitoring and audit programs developed for the System Hardening and Enhanced Vegetation Management programs including 100 percent work verification. For both of these key WMP programs – no miles are recorded as complete in either program until they have been fully verified to be complete. The operating LOB generally validates that the work conducted is accurate and complete while the program data verification is validated by PG&E's Quality Assurance (QA) or IA teams. The operating lines of business that validate that the work is accurate and complete have the expertise to identify any technical issues. The IA teams have expertise in designing data validation and quality monitoring programs. Taken together, the quality monitoring and auditing program that PG&E implements validates both the physical completion of work and the quality of the program data.

Further, during 2019, PG&E provided recurring updates about the status of the 2019 WMP implementation and 2019 WMP performance measures to the Safety Enforcement Division (SED). While certain of these updates were required, PG&E provided additional, voluntary updates to SED in order to keep the Commission aware of the most recent 2019 WMP developments.

5.2.B WMP Deficiencies

B. Identify any deficiencies in the plan or the plan's implementation and correct those deficiencies.

PG&E uses the WMP monitoring and tracking reports and the quality review information to monitor both the progress and quality of the work completed and to identify any program deficiencies. PG&E's WMP PMO is primarily responsible for continually monitoring the individual WMP programs in order to identify any potential deficiencies in the plan or the plan's implementation. In addition, the IA teams or operating lines of business may also identify a deficiency during their review of different WMP program elements. PG&E's senior leaders receive regular WMP reports that they can also use to identify potential deficiencies. Regardless of who identifies a deficiency, all deficiencies are reported to the PMO and the PMO is ultimately responsible for correcting those deficiencies.

To the extent a deficiency is identified, the PMO works with the WMP program leaders to identify what is driving the deficiency and to develop plans to mitigate the underlying issue(s). The PMO carefully monitors the mitigation plan as it is implemented in order to confirm that the deficiency is corrected. Mitigation plans and corrective actions are incorporated into the status updates that the PMO provides to PG&E senior leaders, the federal monitor and the board of directors committee that is monitoring the WMP.

5.2.C Monitor and Audit Inspection Effectiveness

Monitor and audit the effectiveness of inspections, including inspections performed by contractors, carried out under the plan and other applicable statutes and commission rules.

To monitor and audit the effectiveness of inspections carried out under the plan and other applicable statutes and commission rules, PG&E uses a combination of processes, tools and other control points intended to quickly identify anomalies in inspection and/or patrol results. Once identified, PG&E's programs are designed to address the gap, determine the root cause and pursue improvement opportunities.

PG&E is developing processes to build on the methods used during the 2019 WSIP inspections and establish improved inspection processes and inspection control metrics. These improvements will include a combination of data trend analyses, representative sampling, internal audit and/or quality assurance work verification and vendor quality sampling.

Starting in 2020, PG&E will implement an inspection Process Quality function that will be responsible for establishing and monitoring process control measures and notifying responsible parties to take corrective measures when predefined inspection quality standards are not achieved. The Process Quality group exists alongside Internal Audit and Electric Quality Assurance.

PG&E is moving detailed inspection data away from paper-based processes and will be relying more and more on digital tool and technology. As results and data are recorded electronically at the time of the inspection, opportunities for analyzing inspection quality are expanded and accelerated. For example, instead of waiting until a complete plat map is returned and sampled during supervisor work verification or an audit, teams can begin to monitor in-cycle rates of inspector findings to identify potential outliers and more quickly identify areas where additional inspections or re-inspection may be required. PG&E recognizes that rates of inspection and findings will vary by location. Rather than establish a single target metric for inspection productivity and findings, PG&E can use inspection data to develop appropriate inspection metrics for individual locations and then use those metrics to evaluate inspector teams. Using targeted metrics, PG&E can better identify the need for process improvements, additional training or supervision and other corrective actions.

5.2.D Data Used for Wildfire-Related Decisions

D. For all data that is used to drive wildfire-related decisions, including grid operations, capital allocation, community engagement, and other areas, provide a thorough description of the utility's data architecture and flows. List and describe 1) all dashboards and reports directly or indirectly related to ignition probability and estimated wildfire consequences and reduction, and 2) all available GIS data and products. For each, include metadata and a data dictionary that defines all information about the data. For each, also describe how the utility collects data, including a list of all wildfire-related data elements, where it is stored, how it is accessed, and by whom. Explain processes for QA/QC, cleaning and analyzing, normalizing, and utilizing data to drive internal decisions. Include list of internal data standards and cross- reference for they datasets or map products to which the standards apply.

Section 5.3.7.1 provides an overview of PG&E's efforts to bring together critical data into a single environment, enabling data driven approaches to wildfire mitigation initiatives and efforts. That section details the integration of data platforms (repository) to advance PG&E's vision for data analytics.

At a higher level, PG&E's CWSP PMO aggregates data on workstream progress and performance in a weekly dashboard, as discussed in Sections 5.2.A and 5.2.B above. This dashboard tracks limited information on the volume of ignitions and some related measures of wildfire outcomes, but is not focused on "ignition probability and estimated wildfire consequences and reduction."

PG&E's complete GIS dataset includes hundreds of datasets and layers both internally created from company records or analysis and externally acquired from partners, regulators, vendors or government agencies. Once acquired, these datasets are stored in PG&E's GIS system and accessed as needed by system users through various front-end viewers, mapping systems or back-end analysis tools. Some datasets contain confidential information and are therefore only accessible to internal users with the appropriate credentials / login information. The below table provides a selection of GIS datasets applicable to understanding wildfire risk and conditions:

TABLE PG&E 5-2: SELECTION OF GIS DATASETS APPLICABLE TO UNDERSTANDING WILDFIRE RISK AND CONDITIONS

GIS Dataset	Description	Primary Data Elements	How collected	Update frequency
HFTD Boundaries	CPUC-defined HFTD zones	HFTD Tiers	Acquired from CPUC website	Every 10 years
WUI Boundaries	Wildland Urban Interface classifications, per census.gov: a) Urban Areas; b) Urban; c) Rural; d) Highly Rural	Mapbase of WUI areas; Silvix WUI feature class	Acquired from University of Wisconsin-Madison	Created 3/19/19; updated 5/17/19
Electric Transmission Asset Data	Geospatial data on Electric Transmission Assets	Assets	Collected by work management as-built processes	Real time

**TABLE PG&E 5-2: SELECTION OF GIS DATASETS APPLICABLE TO UNDERSTANDING WILDFIRE RISK AND CONDITIONS
(CONTINUED)**

GIS Dataset	Description	Primary Data Elements	How collected	Update frequency
Electric Distribution Asset Data	Geospatial data on Electric Transmission Assets	Assets	Collected by work management as-built processes	Real time
ED work in progress	Geospatial data on planned work in progress	Planned work orders	Initiated by PG&E planning work processes	Real time
ET work in progress	Geospatial data on planned work in progress	Planned work orders	Initiated by PG&E planning work processes	Real time
SAP notification	Geospatial data on corrective work in progress	Planned corrective work	Initiated by PG&E's preventative action programs	Real time
Meteorology	<p>1. Red Flag Warning Days per Fire Index Area (FIA)</p> <p>2. Daily maximum surface windspeed percentiles (95th/99th) from PG&E's 30-yr archived weather re-analysis</p> <p>3. Prevailing surface wind directions from PG&E's 30-yr archived weather reanalysis</p>	<p>1. Red Flag Warning Days</p> <p>2. Daily Maximum Surface Windspeed Percentiles</p> <p>3. Prevailing Wind Direction</p>	<p>1. Iowa State University's Archived National Weather Service Watch/Warnings</p> <p>2. 30-year long-term mesoscale weather model with archived weather re-analyses downscaled to a 3-km grid</p> <p>3. Same as (2)</p>	<p>1. Once a day</p> <p>2. One-time analysis performed in 2019</p> <p>3. Same as (2)</p>
Recent drivers of ignition	A self-propagating fire of material other than electrical with a size greater than 10 acres that is attributable or believed to be attributable to PG&E assets.	Electric corrective tags	Collected by electric compliance	Twice a week: Tuesday and Friday
Census Tracts	Federal census data	Census data	US Census	Every 10 years
OIS Customer Tables	Critical customer information	Customer information	Customer data management processed	Real time
PSPS Data	Duration of PSPS events and area of the grid affected in customer hours per year	Customer outage data from PSPS events	ILIS and CC&B records from PSPS events	After each PSPS event
PGE Service Territory Boundary	Organizational boundary PG&E service territory	Service boundary	NA	Static

5.3 Detailed Wildfire Mitigation Programs

In this section, describe how the utility’s specific programs and initiatives plan to execute the strategy set out in Section 5.1. The specific programs and initiatives are divided into 10 categories, with each providing a space for a narrative description of the utility’s initiatives and a summary table for numeric input in the subsequent tables in this section. The initiatives are organized by the following categories provided in this section:

- 1. Risk assessment and mapping
- 2. Situational awareness and forecasting
- 3. Grid design and system hardening
- 4. Asset management and inspections
- 5. Vegetation management and inspections
- 6. Grid operations and protocols
- 7. Data governance
- 8. Resource allocation methodology
- 9. Emergency planning and preparedness
- 10. Stakeholder cooperation and community engagement

To the extent applicable and relevant, if an electric utility has completed a Safety Model and Assessment Proceeding (S-MAP) and Risk Assessment Mitigation Phase (RAMP) as part of its General Rate Case that identifies safety models or programs the electrical corporation has implemented to mitigate ignition probability and estimated wildfire consequence, then the models or programs identified pursuant to this section must comport with those identified in the S-MAP proceeding. Describe any differences with S-MAP and RAMP and provide rationale.

For each wildfire mitigation activity, report information on:

- 1. Total per-initiative spend in dollars (\$);
- 2. Line miles to be treated (as applicable) 3 in miles (mi);
- 3. Spend per treated line mile (or, where initiative is not implemented on a per-line-mile basis, per total line miles of the system);
- 4. Ignition probability drivers targeted (from the list of ignition probability drivers indicated in utility SDR Table 24 Key drivers of ignition probability, or other as needed);
- 5. Risk reduction of the activity according to utility multi-attribute value function (MAVF); and

- 6. Risk-spend efficiency in dollars per unit of risk reduction; and
- 7. Other risk drivers addressed.

For the quantitative characteristics of the activities, six values shall be reported for each activity. These include numbers for the plan for 2019, actual activity spending and other calculations for the activity as actually implemented in 2019, the plan for year 1 of this WMP, estimates for years 2 and 3 of this WMP, and a subtotal for the 3-year WMP term ("2020-2022 plan total").

For each activity, also:

- 1. Identify whether the program/strategy is existing or new;
- 2. If existing, identify the proceeding where the program/strategy costs have been subjected to Commission review;
- 3. If new, identify any memorandum account where related costs are being tracked and provide an explanation of how double tracking is prevented in the comments; Where a given activity does not take place in geographic distribution across the service territory (e.g., personnel work procedures and training in conditions of elevated fire risk), input "N/A" in the corresponding cell.
- 4. Indicate whether the program/strategy is implemented in compliance with existing regulations or exceeds current regulatory requirements;
- 5. If a program/strategy is identified as meeting a current regulatory requirement, cite the associated order, rule, or code;
- 6. Include comments as needed to clarify or explain the data provided.

The details of PG&E's wildfire mitigation programs are presented in this Section 5.3 and the associated tables are provided in Attachment 1 – *All Tables Required by the WMP Guidelines*. In an effort to create alignment between the utilities, which have some inherent differences, the Wildfire Safety Division (WSD) provided all WMP filers with a standard list of initiatives. This list of initiatives does not always map directly to PG&E's programmatic structure and therefore, some initiatives are not applicable to PG&E, while others have been added. Further, some activities—asset inspections, for example—are performed as an integrated function and cannot be feasibly separated into sub-elements as have been identified as separate initiatives in the provided template. As a result there are a number of initiatives without unique data, as the cost and details of that activity are captured in another portion of Section 5.3. For each initiative, PG&E is providing the information requested in the WMP guidelines to the extent possible. However, it is important to provide some clarifications regarding the information provided throughout Section 5.3.

Financial and Unit Forecasts

With regard to financial information, 2019 actual costs are provided where available and 2020-2022 forecasts are provided as well. These forecasts are subject to changes as a result of operational and regulatory events. For example, as PG&E continues to gain

experience implementing initiatives, the forecasts of cost may need to be updated. Forecasts are also subject to regulatory outcomes, such as approval of the pending settlement in PG&E's 2020 General Rate Case (GRC) Proceeding (Application 18-12-009). With regard to plans and information for the number of units that will be installed for certain initiatives, these are also subject to change. Actual unit installation and operation can be impacted by delays due to permitting, labor availability, and availability of equipment. PG&E expects that the actual unit numbers will change from forecasts, especially for future years such as 2021 and 2022.

Changes in costs and unit installation is even more likely for the 10-year outlook data, given that the initiatives identified can change significantly over the next decade as PG&E gains experience and additional data and information is developed.

Alternatives Analysis

In the January 15, ~~2019~~²⁰²⁰ *WMP Clarification Document*, the WSD added direction for each subsection in Section 5.3 describing the wildfire mitigation initiatives to also include "a list of alternatives considered and the utility's rationale for choosing only the initiatives outlined in the plan and not the alternatives." Due to the rapid evolution of wildfire understanding and the subsequent aggressive implementation of additional wildfire mitigation activities in 2018 and 2019, many of the initiatives were scoped through benchmarking or subject matter expertise. As explained in PG&E's 2019 WMP, PG&E used an analysis of historical ignitions in HFTDs to estimate the number of ignitions that would have been addressed through various approaches, compared to estimated program implementation costs.

For example, in developing the scope for the EVM program this analysis included options such as: (i) high risk species tree work (ultimately selected as part of EVM), (ii) ground to conductor vegetation clearing, (iii) conductor to sky clearing 12' out from conductors, (iv) conductor to sky clearing 4' out from conductors (ultimately selected as part of EVM). PG&E did not have an opportunity to perform detailed alternatives analysis for many of the initiatives included in this section. Quantitative alternatives analysis was performed, however, for some of the larger mitigation activities, such as system hardening and EVM. As PG&E continues to gather additional information, details and experience regarding wildfire risk factors (both likelihood and consequence), including through the implementation of WMP mitigations, it will inform evolution of WMP mitigation plans and increasing quantification of risk reduction and alternatives analysis.

Effectiveness analysis

The initiatives described in PG&E's 2020 WMP remain a work in progress. PG&E is continually learning and incorporating new information regarding wildfire risk factors and how to best mitigate both the likelihood and consequence of potential future ignitions. As such, PG&E will be continually evaluating through various means the effectiveness of these initiatives and adjusting as informed by that feedback. In particular, for asset-oriented initiatives, PG&E will be monitoring outcomes – ignitions and outages, for example – to assess the reduction in such events in areas where mitigations – like system hardening, EVM, non-exempt fuse replacement, etc. – have been applied, as applied to historical baselines and areas where no such mitigations have been applied.

PG&E will incorporate these learnings into future WMPs, including stopping, shifting or accelerating mitigation activities as appropriate.

Risk Quantification

With regard to risk information, the initiatives in this section have been categorized into Mitigations, Controls, Enhanced Controls, Foundational, and Exploratory Projects. These categories are defined as follows and the tables in Section 5.3 are populated accordingly:

- **Mitigations:** Specific additional or enhancement programs, beyond compliance, with specific start and end dates and a project budget, or an additional proposed activity not previously identified. In addition, enhancements to existing controls or newly designed controls could be considered mitigations in the first GRC period they are implemented. Individual mitigation initiatives could be “bundled” together to represent a mitigation plan, and that will be indicated in the respective cell. For mitigations, PG&E has provided data for columns ‘Ignition probability drivers targeted’, ‘Other risk drivers addressed’, ‘Risk reduction’, ‘Risk-spend efficiency’ at the mitigation plan level and not the mitigation initiative level.
- **Controls and Enhanced Controls:** Safety and compliance programs already in place. Individual control initiatives could be “bundled” together to represent a control program, and that will be indicated in the respective cell. For controls, PG&E has provided data for column ‘Ignition probability drivers targeted’ at the control program level and not the control initiative level. Columns ‘Other risk drivers addressed’, ‘Risk reduction’, ‘Risk-spend efficiency’ are not provided. Column ‘Other risk drivers addressed’ is not provided because there is no systematic way to determine which other risk driver other than already indicated in the ‘Ignition probability drivers targeted’ would be applicable. Columns ‘Risk reduction’, ‘Risk-spend efficiency’ are not provided because the baseline risk score already takes these initiatives into account; the risk reduction due to the control is incorporated into the risk score and cannot be confidently separated. PG&E has indicated N/A-Control or N/A-Enhanced Control in the respective cells.
- **Foundational Initiatives and Exploratory Projects:** Enablers to mitigations or controls. They are work needed to implement mitigations or information that would be used to better inform the execution of a control (i.e., investments in IT infrastructure or data gathering). Foundational activities generally do not result in stand-alone risk reduction. As a result, foundational initiatives and exploratory projects do not have associated Risk drivers and Risk reduction scores. For Foundational Initiatives and Exploratory Projects, PG&E has not provided data for columns ‘Ignition probability drivers targeted’, ‘Other risk drivers addressed’, ‘Risk reduction’, ‘Risk-spend efficiency’. PG&E has indicated N/A-Foundational or N/A-Exploratory Project in the respective cells.

Finally, accurately and meaningfully measuring risk is challenging, and while PG&E has made every effort to provide the data requested, we encourage the Commission, the WSD, and stakeholders to continue to facilitate a collaborative discussion on how to most reasonably quantify this topic. In many cases, the data and measures being requested in the WMP Guideline templates are only beginning to be collected, and it will

take years to develop enough data points to determine if these approaches effectively measure risk mitigation. Therefore, a number of initiatives do not have risk reduction quantified and are instead identified as either “foundational” (meaning that this initiative contributes to the risk reduction capability of other initiatives) or “control” (meaning that this initiative is an activity that has existed for such a long time that it is difficult to assess the risk reduction associated with doing so would rather require modeling the risk increase that would occur if this activity were removed from the portfolio of ongoing programs).

Line Miles Treated and Transmission Voltage Definition

The tables in Section 5.3 include data on the number of “line miles treated” for each initiative. This data has been provided, including being estimated, wherever possible, however there are a few limitations that should be understood for these figures. First, a number of programs are not primarily defined by line miles but are defined by a number of assets (like a number of switches to be installed, etc.). In these cases, PG&E made high level assumptions to estimate the approximate number of line miles that could be considered “treated” by such asset-based activities. As a result of these assumptions and estimates the actual number of miles “treated” by these activities may not end up matching with the forecasts provided in Section 5.3. Second, activities at PG&E substations in HFTDs have been generally assigned as treating zero-line miles, since these activities primarily only impact assets within the substation itself and are therefore generally not exposed to the high fire threat conditions (e.g., vegetation within substations is carefully managed to mitigate for vegetation caused ignitions and limit any risk of an ignition that occurs within a substation spreading significantly).

Throughout this WMP, PG&E references Transmission assets and programs. PG&E defines transmission voltage (for this and other regulatory filings) as being 60kV or above, PG&E notes this because in some of the initiative definitions the WMP Guidelines provided referenced transmission as being “at or above 65kV.” PG&E is unable to reconfigure all of its data to align with a cut-off of 65kV instead of the historically used 60kV and therefore, when PG&E references transmission that is reflective of assets operating at or above 60kV.

New or Existing Initiatives

In addition to the programs or initiatives developed specifically to reduce the risk of wildfires, the WMP Guidelines and clarifications direct utilities to describe routine/standard, and emergency response programs, protocols, and initiatives, including planning, preparedness, maintenance, and inspection work streams (Non-Wildfire Programs). These Non-Wildfire Programs could, directly or indirectly, affect wildfire ignition, but have historically been part of our routine/standard or emergency programs and were not specifically created for inclusion in the PG&E WMP. PG&E described these programs and filled out the templates as directed, including providing forecast costs. Generally, inclusion of these Non-Wildfire Programs in the 2020 WMP narrative and charts does not indicate that these programs are part of PG&E’s 2020 WMP. However, some WMP programs are performed in conjunction with Non-Wildfire Programs (e.g., enhanced inspections of HFTD facilities, vegetation work in transmission rights-of-way), and the identified work is “blended” between the WMP and the Non-Wildfire Programs. For example, the enhanced inspections in HFTD

areas have and will continue to identify corrective actions, including repairs and/or replacement of distribution and transmission equipment; some of the work will be conducted through existing programs. PG&E considers the inspections, replacement, and repair work in HFTD areas that exceeds PG&E's currently-adopted forecast for such work to be part of the WMP.

As directed in the WMP Guidelines, the tables associated with Section 5.3 include columns to "1. identify whether the program/strategy is existing or new" and "2. if existing, identify the proceeding where the program/strategy costs have been subjected to Commission review." In completing the tables for Section 5.3, PG&E followed the clarification provided by the WSD on January 29, 2020, to only consider as existing programs "whose costs have been reviewed and approved by the Commission (such as in the GRC)." Therefore, any initiatives or programs that have only been discussed or proposed in the 2019 WMP or other pending proceedings, such as PG&E's 2020 GRC, are listed as "new" and details have been provided on the memorandum account where related costs are tracked. However, for programs identified as "new" where the programs have been discussed in proceedings like the 2019 WMP or 2020 GRC, those filings have been noted in the "proceedings" column to assist readers in understanding where program materials have been submitted previously. ~~These~~ Non-Wildfire Programs are identified as "existing" programs on the Section 5.3 charts, even though 2020 costs are awaiting resolution of PG&E's 2020 GRC, because historical costs of these programs have been authorized in prior GRC decisions.

See Attachment 1, Table 21-30 for the additional information associated with the initiatives discussed in this section.

5.3.1 Risk Assessment and Mapping

Description of programs to reduce ignition probability and wildfire consequence

For each of the below initiatives, provide a detailed description and approximate timeline of each, whether already implemented or planned, to minimize the risk of its equipment or facilities causing wildfires. Include a description for the utility's programs, the utility's rationale behind each of the elements of this program, the utility's prioritization approach/methodology to determine spending and deployment of human and other resources, how the utility will conduct audits or other quality checks on each program, how the utility plans to demonstrate over time whether each component is effective and, if not, how the utility plans to evolve each component to ensure effective spend of ratepayer funds.

Include descriptions across each of the following initiatives. Input the following initiative names into a spreadsheet formatted according to the template below and input information for each cell in the row.

- 1. A summarized risk map showing the overall ignition probability and estimated wildfire consequence
- 2. along electric lines and equipment
- 3. Climate-driven risk map and modelling based on various relevant weather scenarios
- 4. Ignition probability mapping showing the probability of ignition along the electric lines and equipment
- 5. Initiative mapping and estimation of wildfire and PSPS risk-reduction impact
- 6. Match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment
- 7. Weather-driven risk map and modelling based on various relevant weather scenarios
- 8. Other / not listed [only if an initiative cannot feasibly be classified within those listed above]

For each of the above initiatives, describe the utility's current program and provide an explanation of how the utility expects to evolve the utility's program over each of the following time periods:

- 1. Before the upcoming wildfire season,
- 2. Before the next annual update,
- 3. Within the next 3 years, and
- 4. Within the next 10 years.

Overview

PG&E undertook a number of initiatives over the course of 2019 that were aimed at reducing ignition probability and wildfire consequence. Specifically, these initiatives included:

1. Failure Mode and Effects Analysis for its electric distribution, transmission and substation assets.
2. Accelerated and enhanced inspections of all its electric assets within HFTD areas in PG&E's service territory with the objective of identifying and repairing non-conformances on its facilities that pose a safety and/or reliability risk.
3. Thirty (30) year climatology analysis with high-resolution data covering ~80 billion data points to determine historical relationship between wind and electrical outages, as well as correlate historic fire records with weather conditions, topography and vegetation.

Each of these initiatives is described in more detail below, followed by a description of the six specific initiatives identified in the WMP Guidelines. [See Attachment 1, Table 21 for the additional information associated with the initiatives discussed in the section.](#) PG&E has not identified any initiatives for "Other/Not Listed."

Failure Mode and Effects Analysis (FMEA):

As part of PG&E's accelerated inspections of its overhead electric facilities in HFTD areas, PG&E is conducting a Failure Modes and Effects Analysis or "FMEA." The focus of the FMEA was to identify single points of failure of electric system components that could lead to fire ignition and then aid in the development of inspection methods that can most appropriately identify the condition of these respective components. PG&E performed the FMEA using the following methodology:

- Establish a cross-functional team of external professionals and PG&E subject matter experts with experience in field operations, engineering, and asset management.
- Review a list of asset components to identify potential single point failure ignition risks and categorize in asset groups.
- Where available, use published reports, internal reports and subject matter expert interviews to develop an independent list of failure modes.
- Map components to the final list of failure modes and relevant inspection methods.
- In some cases, the failure mode does not have a readily observable issue that can be identified via a visual inspection. In those cases, non-destructive and destructive examination methods may be considered.

Accelerated and Enhanced Inspections

After PG&E identified FMEA focus areas, field inspectors performed inspections of PG&E's facilities across PG&E's HFTD areas. When an inspector identified a

maintenance condition, the inspector either immediately corrected the condition and recorded the correction or recorded the uncorrected condition, which also was reviewed by a centralized review team. In addition, for transmission and distribution facilities, the inspector filled out the initial EC/LC notification tag. PG&E's centralized review team approved and prioritized the corrective notification tag in PG&E's SAP Work Management system. These tags are prioritized based on the risk posed by the condition and urgency of repairs. The table below describes the priority tag classification descriptions PG&E uses to comply with General Order (GO) 95, Rule 18:

TABLE PG&E 5-3: WILDFIRE SAFETY INSPECTION PROGRAM (WSIP) TAG PRIORITY CLASSIFICATION

Tag Priority	Description
A	The condition is of immediate risk of high potential impact to safety or reliability and requires immediate response and continued action until the condition is repaired and no longer presents a potential hazard ("make safe").
B	The condition is of moderate potential impact to safety or reliability. Corrective action is required within 3 months from the date the condition is identified.
E	The condition is of moderate potential impact to safety or reliability. Corrective action is required within 12 months from the date the condition is identified (or within 6 months if tag creates potential fire ignition risk within HFTD Tier 3).
F	The condition is of low potential impact to safety or reliability. <ul style="list-style-type: none">Corrective actions for distribution facilities is recommended to be addressed within 5 years from the date the condition is identified.Corrective actions for transmission facilities recommended to be addressed within 2 years from the date the condition is identified.

30-Year Climatology Analysis:

PG&E also performed a detailed climatology analysis using 30 years of high-resolution model data that generated ~80 billion data points. This robust dataset has been utilized for: (1) determining the historical relationships between wind and outages, (2) correlating historic fire records with weather conditions, topography, vegetation and more; and (3) determining where high risk weather patterns typically occur across the PG&E territory. Specifically, PG&E analyzed the following data sources:

- Weather data (e.g., temperature, relative humidity, wind, precipitation and atmospheric pressure);
- Dead and live fuel moisture levels; and,
- National fire danger rating system outputs

The remainder of this Section 5.3.1 describes specific initiatives PG&E is implementing relative to risk assessment and mapping.

5.3.1.1 A Summarized Risk Map Showing the Overall Ignition Probability and Estimated Wildfire Consequence Along Electric Lines and Equipment

PG&E has leveraged the FMEA that was used to inform its 2019 accelerated and enhanced inspections to develop ignition probabilities for each of the various electric overhead equipment types for electric distribution, transmission and substation facilities. With this information, PG&E created a methodology to perform a wildfire risk ranking of all its electric lines that traverse HFTD areas within PG&E's service territory. The risk ranking there is based on the risk of igniting a wildfire and its associated consequence. In addition to the overall electric line wildfire risk rankings, PG&E has also developed an EC/LC Tag risk ranking methodology to rank identified EC/LC Tags by fire ignition risk potential. Both methodologies are further described below in more detail.

Electric Line Risk Scoring

PG&E has developed an electric line risk prioritization scoring for both its electric distribution and transmission assets to determine a wildfire risk score for each electric line based upon different components of risk. Wildfire Risk is calculated using three components: likelihood of failure, likelihood of spread and consequence, and egress that are further defined as follows and depicted in the following figure below:

1. Likelihood of failure: Relative risk of a circuit causing an outage and ensuing ignition
2. Likelihood of wildfire spread and consequence score: Relative ability ignition spread and quantity of homes or timber affected if ignition occurs
3. Egress score: Ease of access to a community exit and extent of exit, for a mass evacuation

In addition, for transmission lines, additional factors were also considered when developing a transmission line (e.g., line) risk scoring. This includes the consideration of the Operational Priority list of transmission lines from PG&E's Grid Operations and Transmission Planning, the list of the Top 20 Fire Index Areas (FIAs), and the Transmission Operability Assessment (OA) model, which considers the likelihood of a specific transmission line asset failure under certain wind loading conditions. Because of these other factors to consider, transmission assets were prioritized in the following order:

1. Transmission Lines that met three critical conditions: (a) High Operational Priority (as defined by PG&E's Grid Operations and Transmission Planning); (b) High Wildfire Risk area; and (c) Within the top 20 FIAs based on weather conditions.
2. Transmission Lines with both: (a) High Operational Priority; and (b) High Wildfire Risk.
3. Transmission Lines that are within the top 20 FIAs and High Wildfire Risk areas. Ranking follows the results of the OA model by asset and wind speed percent derate.
4. Remaining Transmission Lines in High Wildfire Risk areas ranked by wildfire risk score.

EC/LC Tag Risk Scoring

PG&E has developed a tag prioritization model for both distribution and transmission assets in HFTD areas to determine a wildfire risk score for each tag (e.g., identifying non-conformance on asset). Tag Risk scores are calculated using four components: Asset failure ignition risk, historical asset ignition frequency, likelihood of spread and consequence, and egress. These four components are defined as follows:

1. Asset failure ignition risk: Relative risk of an asset's failure causing an ignition
2. Historical asset ignition frequency:
 - a. For distribution, PG&E's 2014-2019 ignition frequency caused by an identified asset class.
 - b. For transmission, PG&E's 2013-2018 ignition frequency caused by an identified asset class.
3. Likelihood of wildfire spread and consequence score: Relative ability of ignition spread, and quantity of homes or timber affected if ignition occurs
4. Egress score: Ease of access to a community exit and extent of exit, for a mass evacuation

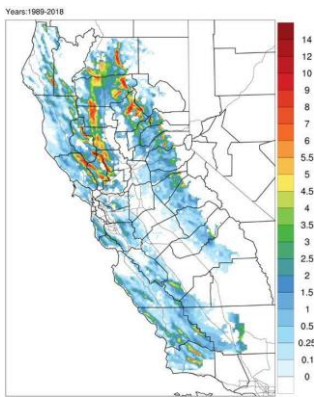
Progress Timeline

1. **Before the upcoming wildfire season**: PG&E will continue to update and refine its risk assessment and mapping activities as described above. PG&E will continue to leverage these initiatives to reduce ignition probability and wildfire consequence.
2. **Before the next annual update**: PG&E will continue to implement the risk assessment and mapping activities described above. Additionally, PG&E will incorporate lessons learned in 2020 as part of the initiatives to reduce ignition probability and wildfire consequence.
3. **Within the next 3 years**: PG&E will continue to update its electric line and EC/LC tag risk scoring using the best available information within the next three years. Based on this information, PG&E will continue to update its risk map showing the overall ignition probability and estimated wildfire consequence along electric lines and equipment.
4. **Within the next 10 years**: PG&E will continue to refine and update its risk scoring and risk mapping as described above within the next ten years.

5.3.1.2 Climate-Driven Risk Map and Modelling Based on Various Relevant Weather Scenarios

PG&E performed a detailed climatology analysis using 30 years of high-resolution model data that generated ~80 billion data points. This dataset allows PG&E to study weather patterns that have occurred over the past 30 years at an hourly resolution and correlate weather to past outage and fire events. One example is evaluating the occurrence of dry, offshore wind patterns such as Diablo wind events. The 30-year analysis revealed for example the locations across the PG&E territory where these events more commonly occur, as depicted in Figure PG&E 5-1 below.

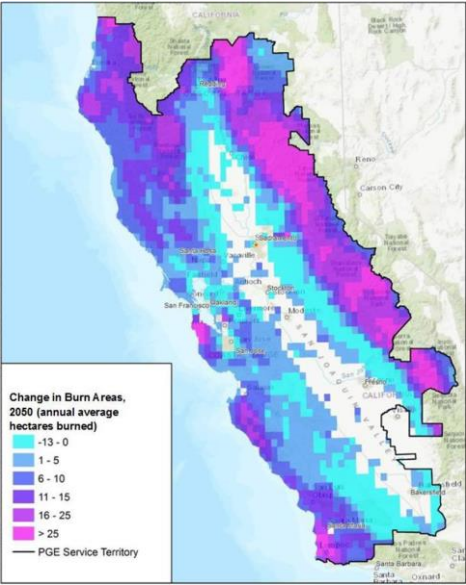
FIGURE PG&E 5-1: AVERAGE ANNUAL NUMBER OF DIABLO WIND EVENTS



PG&E has also partnered with climate change experts to perform a climate change wildfire deep-dive to evaluate forward-looking wildfire projections for 2025, 2035 and 2050. Projections from California's Fourth Climate Change Assessment indicate that wildfire occurrence will significantly increase overall across the PG&E territory over the coming decades. By 2050, under a business-as-usual greenhouse gas emissions scenario ("Representative Concentration Pathway 8.5"), average annual burn areas could increase by a projected 43% relative to the recent historical baseline (which runs 1986- 2005 and excludes recent extreme fires in 2017 and 2018). While wildfire occurrence is projected to increase across a wide swath of the PG&E service territory, the greatest increases are projected in and around existing high-risk areas—particularly

in the Sierra Nevada mountains and foothills. Wildfire trends are projected to continue to intensify in coming decades as a result of worsening climate change conditions. Longer fire seasons, drier summers, and increasing fuel mass will likely drive larger and more pervasive wildfires in the future. Figure PG&E 5-2 below shows the projected change in annual area burned by 2050 relative to historical baseline (areas that lack shading indicate no future wildfire projection).

FIGURE PG&E 5-2: PROJECTED CHANGED IN ANNUAL AREA BURNED BY 2050 RELATIVE TO HISTORICAL BASELINE



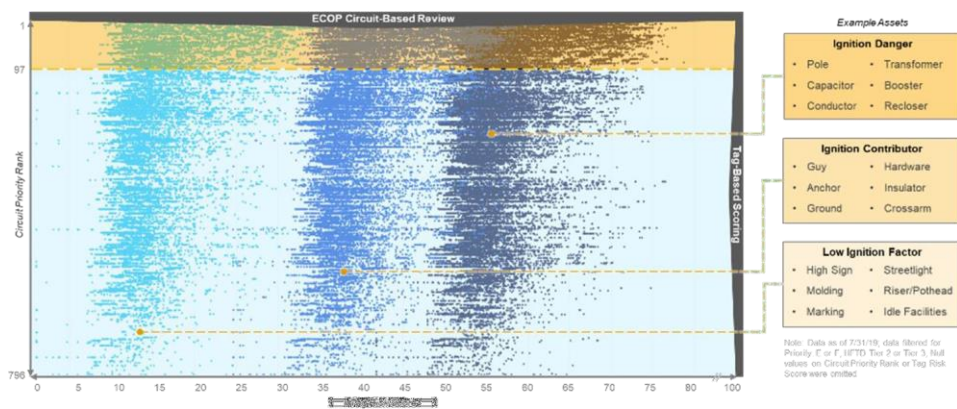
Progress Timeline

1. ***Before the upcoming wildfire season:*** PG&E will continue to leverage detailed climatology analyses to inform wildfire mitigation activities.
2. ***Before the next annual update:*** PG&E will continue to leverage detailed climatology analyses to inform wildfire mitigation activities. Additionally, PG&E will incorporate lessons learned in 2020 into its on-going plans.
3. ***Within the next 3 years:*** PG&E will continue to evaluate and leverage detailed climatology analyses to inform wildfire mitigation activities within the next three years.
4. ***Within the next 10 years:*** PG&E will continue to evaluate and leverage detailed climatology analyses to inform wildfire mitigation activities within the next ten years.

5.3.1.3 Ignition Probability Mapping Showing the Probability of Ignition Along the Electric Lines and Equipment

PG&E has also determined the probability of ignition along its electric lines and equipment that traverse HFTD areas within its service territory. For the electric distribution system, PG&E has further analyzed the probability of ignition for each piece of equipment and device on its overhead electric system. This granular information also informed the prioritization of non-conformance items identified during the 2019 accelerated and enhanced inspections. Included below as Figure PG&E 5-3 is an example of PG&E's distribution line wildfire risk ranking with the probability of ignition on line equipment that were identified using non-conformance items from inspections. This information was also used to inform PG&E's distribution system hardening priorities.

FIGURE PG&E 5-3: PG&E'S DISTRIBUTION LINE WILDFIRE RISK RANKING WITH PROBABILITY OF IGNITION



Progress Timeline

1. ***Before the upcoming wildfire season:*** PG&E will continue to leverage its ignition probability mapping showing the probability of an ignition along the electric lines and equipment to inform wildfire mitigation activities.
2. ***Before the next annual update:*** PG&E will continue to leverage its ignition probability mapping inform wildfire mitigation activities. Additionally, PG&E will incorporate lessons learned in 2020 into its on-going plans.
3. ***Within the next 3 years:*** PG&E will continue to update, evaluate and leverage its ignition probability mapping to inform wildfire mitigation activities within the next three years.
4. ***Within the next 10 years:*** PG&E will continue to update, evaluate and leverage its ignition probability mapping to inform wildfire mitigation activities within the next ten years.

5.3.1.4 Initiative Mapping and Estimation of Wildfire and PSPS Risk-Reduction Impact

As discussed in Section 5.3.1.1, PG&E has prepared a wildfire risk ranking for each of its electric transmission and distribution lines that traverses through HFTD areas within PG&E service territory, which was used to inform its system hardening prioritization approach. In addition, PG&E has also determined a wildfire risk ranking for each of its distribution lines by circuit protection zone.

Progress Timeline

1. ***Before the upcoming wildfire season:*** PG&E will continue to review and refine its wildfire risk ranking and will use this analysis to inform wildfire mitigation decisions.
2. ***Before the next annual update:*** See above.
3. ***Within the next 3 years:*** See above.
4. ***Within the next 10 years:*** See above.

5.3.1.5 Match Drop Simulations Showing the Potential Wildfire Consequence of Ignitions That Occur Along the Electric Lines and Equipment

PG&E tested the capabilities offered by two leading experts of wildfire spread modeling in 2019: Technosylva and REAX. The weather and fuel moisture data needed to run these models is provided by PG&E's internal high-resolution weather, POMMS. One system PG&E deployed simulates >70 million fire spread cases daily originating near PG&E's overhead assets in HFTD areas to determine areas that have the highest risk of fire spread consequences (e.g., acres burned, homes and population at risk) through the available forecast period (currently the next 72 hours).

Both systems deployed can simulate fires on-demand to determine where fires may potentially spread in the next hour to few days. PG&E is also working with these experts to simulate millions of fires along overhead assets during the highest risk periods from PG&E's high-resolution climatology to determine areas the higher risk of wildfire exposure relative to others. More detail can be found in Section 5.3.2 – Situational Awareness and forecasting.

Prior to the next annual WMP update or earlier, PG&E plans to leverage these capabilities to inform risk management, PSPS operational decisions, and as an opportunity to further refine PG&E's method for determining potential wildfire consequences of ignitions. PG&E also plans to leverage this data to help inform prioritization of system hardening priorities.

Progress Timeline

1. ***Before the upcoming wildfire season:*** PG&E will continue to evaluate the wildfire spread modeling data to inform wildfire mitigation activities.
2. ***Before the next annual update:*** Prior to the next WMP update PG&E will further leverage the capabilities described above to inform risk management, PSPS operational decisions, as an opportunity to further refine PG&E's method for determining potential wildfire consequences of ignitions and to help inform prioritization of system hardening priorities.
3. ***Within the next 3 years:*** PG&E will continue to leverage the wildfire spread modeling data to inform wildfire mitigation activities within the next three years.
4. ***Within the next 10 years:*** PG&E will continue to leverage the wildfire spread modeling data to inform wildfire mitigation activities within the next three years.

5.3.1.6 Weather-Driven Risk Map and Modelling Based on Various Relevant Weather Scenarios

PG&E has developed several real-time and forecast weather-driven risk maps that help inform operational decisions. Many of these maps have been informed by evaluating historic weather scenarios. For example, PG&E has performed a comprehensive meteorological analysis to determine the historical relationships between wind and outages across PG&E's electric system. Specifically, PG&E analyzed wind speeds in the vicinity of every unplanned outage (~300,000 outage data points) across 10+ years of outage history using PG&E's outage databases and PG&E's wind climatology that contains 30 years of hourly wind speeds (>5 billion data points).

As a result of this analysis, PG&E first developed location-dependent wind-outage relationships across its diverse territory to be applied against forecast data. PG&E also developed interactive application displays, based on high-resolution forecast data, when wind-related unplanned outages are more likely to occur in PG&E's electric system. This application can also display near real-time wind-outage frequencies based on the NCEP Real-Time Mesoscale Analysis (RTMA) as well as live location-specific outage data for operational awareness. This is an all-season tool that assists operational meteorologists with winter storms and PSPS events. More information about weather-driven risk maps as it relates to outage potential and fire potential can be found in Section 5.3.2.

Progress Timeline

1. ***Before the upcoming wildfire season:*** PG&E will continue to leverage its weather driven risk maps and modeling data to inform wildfire mitigation activities.
2. ***Before the next annual update:*** PG&E will continue to leverage its weather driven risk maps and modeling data to inform wildfire mitigation activities. Additionally, PG&E will incorporate lessons learned in 2020 into its programs going forward.
3. ***Within the next 3 years:*** PG&E will continue to leverage weather driven risk maps and modeling data to inform wildfire mitigation activities within the next three years.
4. ***Within the next 10 years:*** PG&E will continue to leverage weather driven risk maps and modeling data to inform wildfire mitigation activities within the next three years.

5.3.2 Situational Awareness and Forecasting

Description of programs to reduce ignition probability and wildfire consequence

For each of the below initiatives, provide a detailed description and approximate timeline of each, whether already implemented or planned, to minimize the risk of its equipment or facilities causing wildfires. Include a description of the utility's initiatives, the utility's rationale behind each of the elements of the initiatives, the utility's prioritization approach/methodology to determine spending and deployment of human and other resources, how the utility will conduct audits or other quality checks on each initiative, how the utility plans to demonstrate over time whether each component of the initiatives is effective and, if not, how the utility plans to evolve each component to ensure effective spend of ratepayer funds.

Include descriptions across each of the following initiatives. Input the following initiative names into a spreadsheet formatted according to the template below and input information for each cell in the row.

- 1. Advanced weather monitoring and weather stations
- 2. Continuous monitoring sensors
- 3. Fault indicators for detecting faults on electric lines and equipment
- 4. Forecast of a fire risk index, fire potential index, or similar
- 5. Personnel monitoring areas of electric lines and equipment in elevated fire risk conditions
- 6. Weather forecasting and estimating impacts on electric lines and equipment
- 7. Other / not listed [only if an initiative cannot feasibly be classified within those listed above]

For each of the above initiatives, describe the utility's current program and provide an explanation of how the utility expects to evolve the utility's program over each of the following time periods:

- 1. Before the upcoming wildfire season,
- 2. Before the next annual update,
- 3. Within the next 3 years, and
- 4. Within the next 10 years.

Overview

In compliance with D.19-05-037, Ordering Paragraphs 11 and 12, and as proposed in Advice Letter 4117-G/5582-E, PG&E engaged and collaborated with external stakeholders regarding situational awareness information sharing and will continue

these efforts in the future. In 2019, PG&E coordinated multiple meetings to discuss information sharing capabilities such as satellite fire detection and wildfire cameras. Participants included representatives from CAL FIRE, USFS, USDA, BLM, county OES coordinators, and multiple local fire departments. The stakeholders involved in these discussions expressed interest in further collaboration with PG&E to improve fire situational awareness. In 2020, PG&E will continue these collaborative discussions and work towards more formal agreements for information sharing. In addition, PG&E is very interested in working collaboratively with the newly established Wildland Forecast and Threat Intelligence Investigation Center defined by SB209.

Currently PG&E is providing multiple types of information and data sharing through various platforms accessible to our public partners. Below, PG&E provides a summary of its approach to information and data sharing. More details about each data set and platform are included in the narratives throughout this Section 5.3.2.

- During high risk fire weather events, a PG&E meteorology participates in a daily interagency call hosted by Northern of Southern Geographic Area Coordination Center (GACC) and shares relevant forecast information for upcoming high-risk periods. The National Weather Service and regional weather offices are present on the call.
- PG&E operates more than 600 weather stations to obtain and utilize real-time, local weather information. All data collected from these stations are made publicly available in near-real time at www.pge.com/weather to benefit the public, federal, state, and local agencies. PG&E also continues to work with local, state, and federal agencies on where these stations should be deployed for maximum public benefit and PG&E welcomes new partnerships on this program.
- During fire season, PG&E publishes a PSPS forecast that highlights the potential for a PSPS over the next 7 days and includes a forecast discussion of current and future conditions compiled by a fire scientist or meteorologist.
- PG&E shares its daily Fire Potential Index (FPI) forecasts with the CPUC and Cal OES. PG&E is open to sharing daily utility FPI forecast data with all stakeholders and greatly values the role of state and federal agencies play in communicating fire danger and risk to the general public.
- During PSPS events, agencies have been welcomed to participate in PG&E's Emergency Operations Center (EOC) operations to observe and provide input and feedback. During some of the 2019 PSPS events, members from the CPUC, Cal OES, and CAL FIRE were present, including at times decisions when decisions were made to de-energize for public safety.
- PG&E also developed and deployed an industry-leading satellite fire detection system in 2019 that uses remote sensing data from five geostationary and polar orbiting satellites to detect fires. PG&E is actively sharing automated email fire alerts with CAL FIRE through the California National Guard and with numerous county and local fire departments. PG&E is open to sharing this data with interested stakeholders and to the general public.

- Wildfire cameras are used by CAL FIRE, Cal OES, and PG&E to identify, confirm, and track wildfires. This allows firefighting agencies to be alerted quickly and to deploy resources directly to the areas where they can have the greatest impact. The high-definition, pan tilt zoom cameras will improve PG&E's overall situational awareness and be a valuable tool for assisting the WSOC, first responders, and fire agencies. First responders and external agencies such as CAL FIRE and the USFS currently have access to control PG&E's cameras (pan/tilt/zoom) to assist with their respective fire response efforts. Live feeds and time-lapse data from this camera network are available to the public at <http://www.alertwildfire.org>. Beyond 2022, PG&E plans to reassess the camera network coverage as several other agencies such as Sonoma Water, USFS, CAL FIRE, and other utilities are also installing wildfire cameras. Similar to the weather station program, PG&E welcomes input from external parties on camera deployment to maximize public safety and efficiency.
- PG&E's is expanding their Live Fuel Moisture (LFM) sampling program in conjunction with San Jose State University. Results are planned to be uploaded to the USFS National Fuel Moisture Database for public use as long as the database is maintained. This database is available here: <https://www.wfas.net/index.php/national-fuel-moisture-database-moisture-drought-103>. Beyond 2021, PG&E will evaluate adding additional sites based on needs of the utility and industry. PG&E is open to working with external agencies to select sampling sites for maximum benefit.

See Attachment 1, Table 22 for the details and data associated with the initiatives discussed in this section.

5.3.2.1 Advanced Weather Monitoring and Weather Stations

PG&E's Meteorology team currently consists of ten full-time degreed and experienced meteorologists and five degreed contract meteorologists that are industry experts in operational meteorology, utility meteorology, outage prediction, fire science, data science, cloud computing, atmospheric modeling, application development and data systems development. Most members of the team hold advanced degrees and the team has several alumni from the SJSU Fire Weather Research Laboratory (<https://www.fireweather.org/>). The team's responsibilities include monitoring and forecasting weather for utility operations, as well as maintaining, developing and deploying meteorological and decision support models for utility operations.⁸

PG&E utilizes public and proprietary state-of-the-art weather forecast model data and operates an in-house, high-resolution meteorological modeling system to forecast weather conditions, outage potential, and fire potential. PG&E also has a robust history of weather data including over 500,000 images from the North American Regional Reanalysis (NARR), as well as a high-resolution 30-year, hourly climatology of weather and fuels data. These historical datasets are utilized to put forecasts into perspective. PG&E also leverages publicly available forecast information from government agencies such as the National Weather Service (NWS) and GACCs Predictive Services as well as coordinates directly with meteorologists from these agencies on daily interagency conference calls when there is an increased fire potential. PG&E acquires and processes over a terabyte of public and proprietary weather data daily from several sources including, but not limited to:

- European Centre for Medium-Range Weather Forecasts (ECMWF)
- The ECMWF Ensemble Prediction System (EPS)
- Global Forecast System (GFS)
- Global Ensemble Forecast System (GEFS)
- Canadian Meteorological Centre (CMC) Global Model
- North American Mesoscale Model (NAM)
- High Resolution Rapid Refresh (HRRR)
- High Resolution Ensemble Forecast (HREF) model suite
- NanoWeather Uncoupled Surface Layer (USL) model
- Clean Power Research, LLC solar irradiance model
- Desert Research Institute (DRI) California and Nevada Smoke and Air Committee (CANSAC) Weather Research and Forecast (WRF) model

⁸ In 2020 PG&E is equipping a Meteorology Operations Center at an existing facility. The details for the Center are in Table 22, Section 7-2, Other, Meteorology Operations Center.

- PG&E's WRF model; the PG&E Operational Mesoscale Modeling System (POMMS)
- National Center for Environmental Prediction Real-Time Mesoscale Analysis
- Satellite and Fire Detection data from GOES-16, GOES-17, MODIS-AQUA, MODIS-TERRA, and Suomi-NPP
- NOAA Radar data
- Upper air observations from NOAA soundings and various wind profilers
- Lightning Data from the TOA Systems' Global Lightning Network
- Real-time weather station data from several hundred weather stations

PG&E first deployed the high resolution in-house mesoscale forecast model, POMMS, in November of 2014 and continues to improve and build upon the model framework to generate short to medium-term weather, outage, and fire potential forecasts across the PG&E service territory. POMMS is a high-resolution weather forecasting model that generates important fire weather parameters including wind speed, temperature, relative humidity, and precipitation at a 3-kilometer (km) resolution. Outputs from POMMS are used as inputs to the National Fire Danger Rating System, the Nelson Dead Fuel Moisture (DFM) model, and a proprietary Live Fuel Moisture (LFM) model to derive key fire danger indicators such as 1hr, 10hr, 100hr, 1000hr DFM, LFM, and NFDRS outputs such as the Energy Release Component, Burning Index, Spread Component and Ignition Component.

In late 2018 to 2019, PG&E successfully completed one of the largest known high-resolution climatological datasets in the utility industry: a 30-yr, hourly, 3 km spatial resolution dataset consisting of weather, dead and live fuel moistures, NFDRS outputs, and fire weather derivative products such as the Fosberg Fire Weather Index (FFWI). The quantity of data generated at the near-surface was near 80 billion datapoints. With this robust weather and fire parameter dataset, PG&E Meteorology sought to develop outage and fire potential models in 2019 utilizing best-practices deployed in the utility industry, fire science and data science communities.

The probability of a utility-caused fire ignition is related to a power outage from any source (e.g., vegetation failure, equipment failure, animal contact, car-pole). To better understand and forecast the potential of an outage, PG&E developed and then operationally deployed the Outage Producing Wind (OPW) model. The OPW model was built using PG&E outage data from 2008 – 2018 (~300,000 outage events) and PG&E's robust wind climatology, which contains 30 years of hourly wind data at a 3 km spatial resolution (>5 billion wind data points). Each hour of the 30-year climatology was processed to determine wind speeds in the vicinity of each outage. Location-specific distributions of wind and outage data were created from this process, allowing construction of location-specific wind-outage models. Through PG&E's study and experience forecasting outage activity as part of the SOPP model for over a decade, it was understood a single wind-outage model was insufficient to represent the wind-outage relationship across PG&E's entire territory. The OPW model and construction is discussed in more detail later in this section.

In order to evaluate the potential for large fires, PG&E significantly enhanced the FPI model in 2019 building upon utility best-practices. The PG&E FPI model was built and calibrated using a USFS dataset containing fires in the PG&E territory from 1992 – 2018. PG&E built and evaluated over 4,000 combinations of the FPI model using numerous weather components, fire weather indices (Fosberg Fire Weather index, the Hot-Dry-Windy Index, the Santa Ana Wildfire Threat weather index), outputs from NFDRS, Nelson DFM model, a machine-learning derived LFM model, and 'containment' and 'land characteristic' features such as road density, distance to nearest fire station, land-use type among several others. The PG&E FPI deployed in 2019 combines weather (wind, temperature, and relative humidity) and fuels (10hr dead fuel moisture, live fuel moisture, and fuel type such as grass, shrub/brush, timber) into an index that represents the probability for large fires to occur. The FPI model is run on the same 3-km resolution dataset as the high-resolution weather and OPW model.

In 2019, PG&E surpassed 600-weather stations installed, which is the largest known utility owned and operated weather station network in the world. Each weather station deployed records and reports meteorological data every 10 minutes and all data is made publicly available. This data can be accessed in real-time through the National Weather Service weather and hazards data viewer, Mesowest, the National Center for Environmental Prediction (NCEP) Meteorological Assimilation Data Ingest System (MADIS), or at www.pge.com/weather. In 2019, PG&E meteorologists met with representatives from NWS, CAL FIRE, and others to coordinate on where deployment of weather stations would be useful to not only PG&E, but to other agencies and the public. In 2020 and beyond, PG&E plans to significantly expand this network.

PG&E also developed and deployed a state-of-the-art satellite fire detection system in 2019 that uses remote sensing data from 5 geostationary and polar orbiting spacecraft to detect fires. PG&E partnered with the Space Science and Engineering Center from the University of Wisconsin, which provides PG&E with a customized, granular feed of fire detections from the next-generation GOES satellites. PG&E also obtains polar-orbiting satellite fire detection data from NASA. PG&E developed a proprietary application and algorithms in-house to consolidate fire detections as they arrive from several satellites and disseminate alerts via the internal web application and email. The web application allows PG&E's analysts in the WSOC, meteorologists and others to track fire detections in near-real time, evaluate the intensity of fires via the Fire Radiative Power (FRP) outputs, as well as track the general spread of fires. This system is used in concert with the weather station network described above, the expansive high-resolution camera network deployed in PG&E's territory, and several other sources. PG&E is sharing fire detection alerts with the CA National Guard and with county and local fire departments and is open to sharing the data with all interested stakeholders.

5.3.2.1.1 Weather Prediction Program Using High Performance Cloud Computing

PG&E is actively partnering with multiple external experts in numerical weather prediction to develop the next version of the PG&E Operational Mesoscale Modeling System, POMMS 3.0, in time for the 2020 fire season. The current version of POMMS provides 3 km weather and fuel moisture forecast data with a forecast lead time of near 80 hours. The forecast is updated 4 times daily, approximately every 6 hours. From Q4 2019 to Q1 2020, PG&E and external experts will test and validate several model configurations of the WRF system in order to deploy the most accurate version of POMMS possible in 2020. To help achieve this goal, PG&E plans to deploy the National Center for Atmospheric Research (NCAR) Model Evaluation Tools (MET) verification package on internal systems. NCAR-MET is a state-of-the-art suite of verification tools that is highly customizable. PG&E plans to increase the POMMS model resolution from 3 km to 2 km and increase the model lead time to near 96 hours. PG&E also plans to deploy 0.67 km model forecasts on demand during high risk periods to provide enhanced model granularity during high risk periods. PG&E also plans to deploy a high-resolution model ensemble package with 8 model members at 2 km resolution as well. This will significantly increase the amount of forecast data generated daily near the surface from 100 million data points in 2019 to over 1 billion in 2020. PG&E plans to keep its current 3 km POMMS model operational through at least 2020 to compare against the new 2 km version of POMMS.

PG&E plans to utilize a scalable, high-performance cloud computing environment to achieve the significant increase in computation required to run the high-resolution weather models and post-process data multiple times per day. The cloud computing environment will be disaster recovery tested and will have the ability to be run across separate geographic computing regions. This environment was selected over an *in-situ* solution (i.e., on-site high-performance computer cluster) as it provides more flexibility to scale should modeling requirements and computation demand change overtime.

PG&E also plans to reproduce the 30-year weather and fuel moisture climatology at the same 2 km resolution and model configuration as the enhanced operational POMMS model described above. Once completed, this data stack will consist of near 180 billion datapoints of weather and fuels near the surface to evaluate historical relationships of outages and fire potential. Since this dataset will cover most of California, PG&E believes it will have significant benefit to the scientific community. PG&E is open to partnering with academic institutions focused on meteorology, fire weather and fire science in order to jointly derive value from these robust data. This historical climatology is expected to be completed in late Q2 to Q3 2020.

After the historical data stack is re-created, PG&E plans to re-calibrate the OPW and FPI models using the new 2 km historical dataset, so they can be applied in forecast mode at the same resolution. PG&E also plans to deploy an improved 2 km resolution gridded LFM model potentially using two different approaches: (1) using historical and near-real-time remotely sensed data to model LFM; and (2) develop a machine-learning model trained and tested on National Fuel Moisture Database (NFMD) observations. New and old growth live fuel moisture models from multiple plant species (e.g., chamise and manzanita) are planned to be developed in Q2 to Q3 2020.

PG&E also plans to work with an external partner to develop and deploy a short to long-range (2 – 4 week) Diablo wind event forecasting system based on statistical, machine learning and/or artificial intelligence techniques by Q3 2020. A longer lead-time of an upcoming offshore, Diablo wind events would provide crucial preparation time for PG&E and potential communities impacted by these events.

Beyond 2020, PG&E Meteorology plans to evaluate the model performance of the 2 km forecasts for the 2020 fire season and apply any lessons learned for the 2021 fire season. Overtime, it is expected that weather models will continue to improve. Over the next decade, PG&E Meteorology will assess its modeling capabilities annually and seek to make improvements or utilize new modeling and data science techniques as needed.

In Figures PG&E 5-4, 5-5, and 5-6 below, PG&E provides an example product menu for the POMMS model showing a sample array of model output. Model output visualizations of wind gusts and temperature centered over the SF Bay Area below.





FIGURE PG&E 5-5: POMMS MODEL OUTPUT, WIND GUSTS/WIND SPEED BARBS

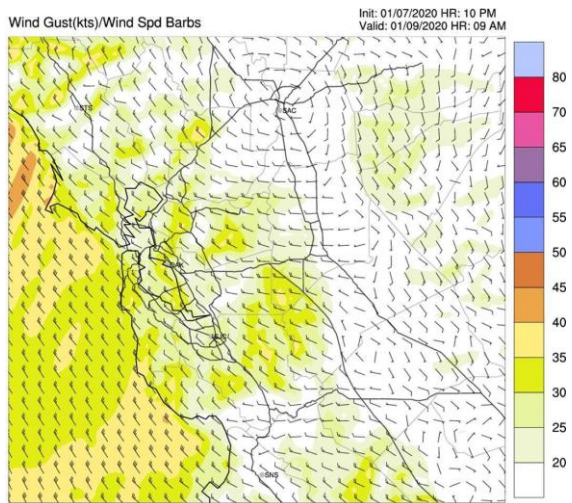
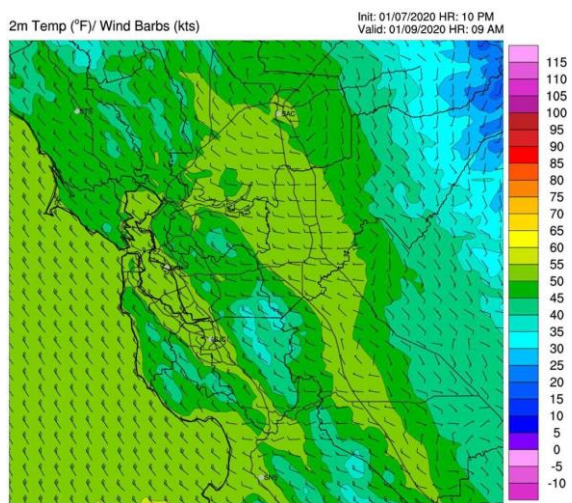


FIGURE PG&E 5-6: POMMS MODEL OUTPUT, 2M TEMPERATURE/WIND BARB



5.3.2.1.2 Wildfire Spread Models

In late 2019, PG&E partnered with external experts in the fire modeling field to test and deploy internal and cloud-based wildfire spread model capabilities to better understand the technology and to test integration into current decision support frameworks. One system PG&E deployed simulates >70 million fire spread cases daily originating near PG&E's overhead assets in the high fire threat district. This is the largest known utilization of fire spread technology in the utility industry. The fire spread outputs (e.g., potential number of acres burned, and population impacted) can be summarized per overhead circuit and line segment in forecast mode to determine the highest risk circuits every 3 hours.

Fire simulations are driven by PG&E's high resolution POMMS weather and fuel model outputs. Fire simulation outputs are available across a 3-day forecast horizon. In Q3 2020 and beyond, PG&E plans to enhance this model framework by improving several of the input data sources and working with industry experts to enhance modeling capabilities and fire consequence outputs and metrics. The potential enhancements in 2020 include: produce territory-wide fire risk scores based on tens of million fire spread simulations daily, update and enhance the underlying fuel model layer to more accurately describe the amount, quantity and arrangement of vegetation and type of vegetation available for combustion, improving the fidelity and granularity of the high resolution weather inputs to 2 km, develop probabilistic fire spread results based on stochastic modeling techniques, evaluate remote sensing technologies to improve live fuel moisture model inputs, and integrate other sources of data into the platform including satellite-based fire detections. In addition, PG&E is also working with external experts to simulate over a billion fires across historically high fire potential days. This work is planned to be completed before the 2020 fire season and will help put daily fire spread risk scores in perspective.

In 2019, PG&E also deployed a separate fire spread model called ElmFire, that uses a Monte Carlo modeling technique to produce probabilistic fire spread results. This modeling system was also coupled with PG&E's Fire Detection and Alert system to automatically generate fire simulations.

In Q3 2020, PG&E will evaluate incorporating the fire spread model consequence into decision support frameworks including PSPS. In 2021, PG&E will assess the 2020 fire season and results of the fire spread modeling and identify areas of improvement. These may include improvements to the input weather data stream, fuel models, and further leveraging remote sensing capabilities such as LiDAR and satellite data.

In Figure PG&E 5-7 and Figure PG&E 5-8 below, PG&E provides an example output from the fire spread model application and example output from the fire spread model application.

FIGURE PG&E 5-7: EXAMPLE OUTPUT FROM THE FIRE SPREAD MODEL APPLICATION –
COLOR CODING REPRESENTS THE MAXIMUM FIRE SIZE SIMULATED FROM
EACH OVERHEAD CIRCUIT

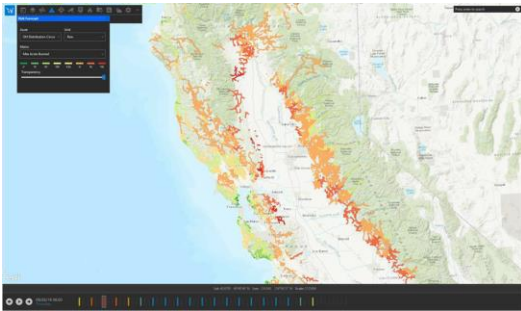
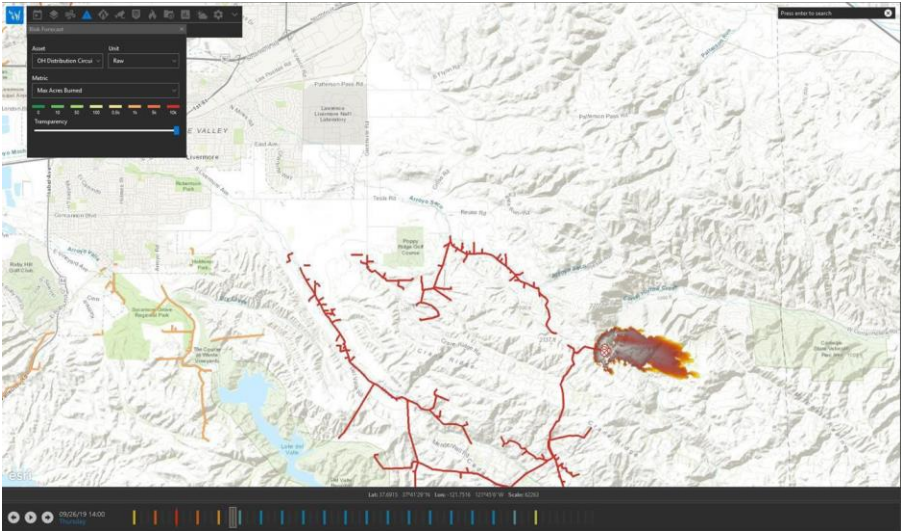


FIGURE PG&E 5-8: EXAMPLE OUTPUT FROM THE FIRE SPREAD MODEL APPLICATION



5.3.2.1.3 Weather Stations

Data from weather stations installed in PG&E's service area are used to help forecast and monitor for high fire-risk weather conditions. This data helps inform implementation of additional precautionary measures such as PSPS.

As of January 1, 2020, PG&E operates and maintains more than 600 weather stations, the largest known utility-owned weather station network in the world. This robust weather station network is used to obtain real-time, local weather information to facilitate operational decision making and support safe operation of facilities. Weather station data is also used to validate model forecasts and to test new high-resolution model configurations. The weather stations record wind speed, temperature and humidity, which are the three most important fire weather parameters.

In 2018 into 2019, PG&E developed an internal web application that presents real-time weather station data from multiple networks (PG&E, NWS, RAWS) and color codes the observation based on the Fosberg Fire Weather Index (FFWI) being observed (see Figure 5-10 and 5-11 below). The FFWI is an index that uses wind speed, temperature and relative humidity to capture the fire weather conditions being observed. Meteorologists can interact with the data and view data from individual stations or click on a Fire Index Area (FIA) to see a summary of conditions from each weather station in the FIA over the past 24 hours. PG&E also developed the PG&E Wind Alert System (PWAS) that displays and disseminates alerts when real-time data collected from PG&E, RAWS, and NWS weather station approach or exceed defined wind thresholds. The internal web application allows users to define the areas(s) where alerts are received.

In Figures 5-9, 5-10, and 5-11 below, PG&E provides: (1) a photograph of a weather station; (2) real-time weather station data from multiple networks; and (3) a snapshot of PG&E's Wind Alert System that displays and also disseminates alerts when wind speeds exceed thresholds.

FIGURE PG&E 5-9: PG&E WEATHER STATION AND ASSOCIATED INSTALLATION DETAIL

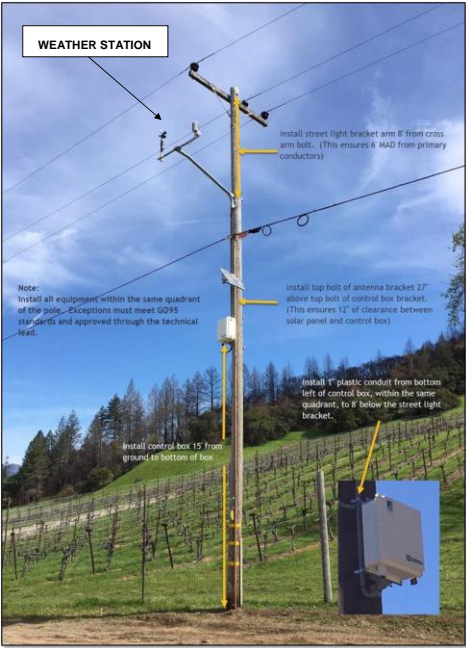


FIGURE PG&E 5-10: INTERNAL WEB APPLICATION DEVELOP BY PG&E THAT SHOWS REAL-TIME WEATHER STATION DATA FROM MULTIPLE NETWORKS (PG&E, NWS, RAWS)

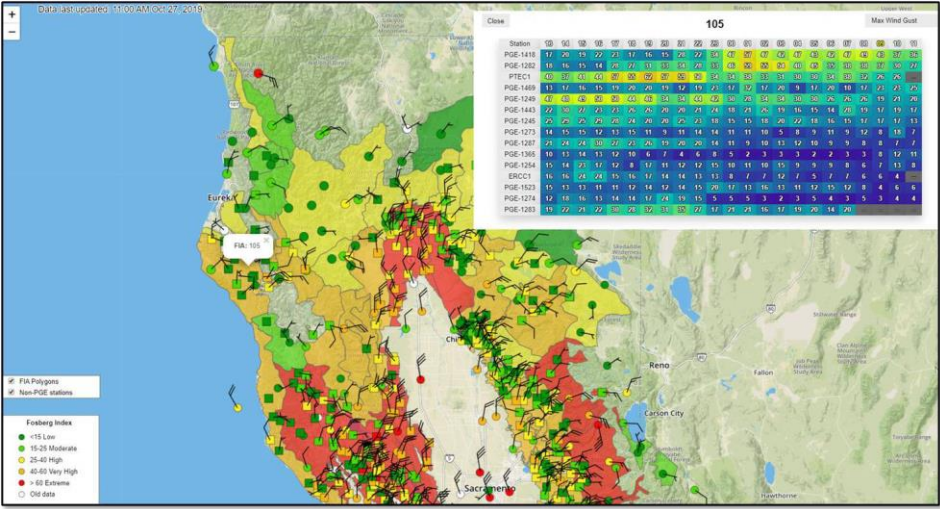
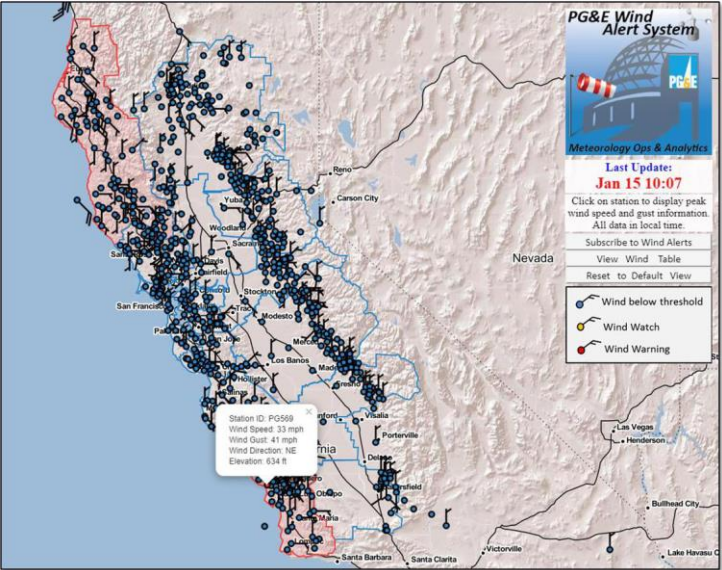


FIGURE PG&E 5-11: THE PG&E WIND ALERT SYSTEM THAT DISPLAYS AND ALSO DISSEMINATES ALERTS WHEN WIND SPEEDS EXCEED THRESHOLDS – USERS CAN CUSTOMIZE ALERTS TO ONLY RECEIVE ALERTS FOR THE AREA(S) NEEDED



5.3.2.1.4 Wildfire Cameras

Wildfire cameras are used by CAL FIRE, Cal OES, and PG&E to identify, confirm, and track wildfires and general conditions in real-time. This allows firefighting agencies to more quickly confirm reports of fire, assess the size and spread, and ultimately help deploy resources directly to areas that can have the greatest mitigating impact.

In 2018, PG&E piloted the installation of nine cameras in the CPUC HFTD areas to test the technology. In 2019, PG&E installed over 120 more high-definition cameras and as of January 1, 2020 operates over 130 wildfire cameras. An informative camera and weather station installation video can be viewed here:

https://players.brightcove.net/1691765962001/SkPAPXDi_default/index.html?videoId=6066367720001.

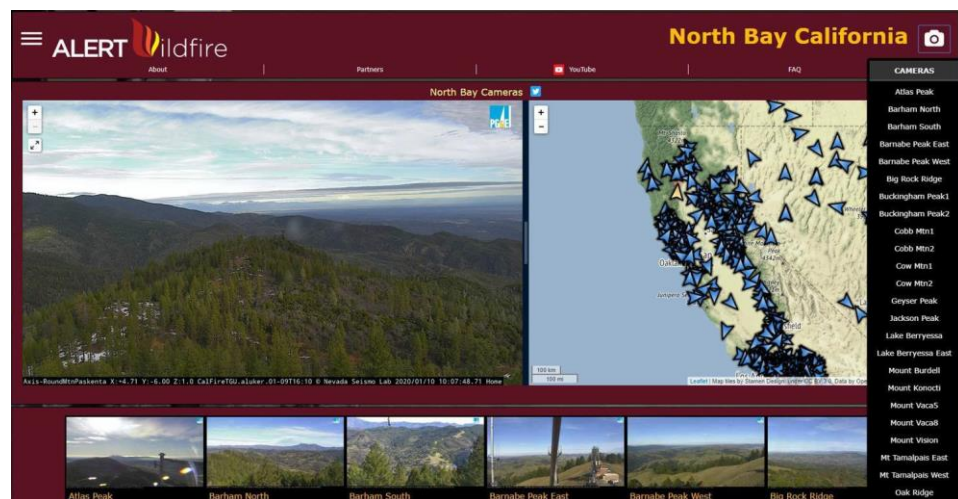
PG&E plans to deploy an additional 200 cameras by December 31, 2020. PG&E's long-term goal is to establish roughly 90 percent coverage across high fire-risk areas by 2022, which may require the installation of approximately 600 cameras. The number of cameras available has already grown beyond the capability to manually monitor each feed. PG&E leverages other technology, such as the satellite fire detection data discussed below, to help determine which camera(s) to view and where it(they) should be directed. PG&E also plans to investigate automatically rotating and zooming nearby cameras to view emerging incidents by integrating fire incident reports such as detections from the PG&E Fire Detection and Alert System. On an on-going basis, PG&E evaluates areas where camera coverage may be lacking and looks for opportunities to install cameras with a maximum viewshed.

Beyond 2022, PG&E plans to reassess the camera network coverage as several other agencies such as Sonoma Water, USFS, CAL FIRE, and other utilities are also installing wildfire cameras. Similar to the weather station program, PG&E welcomes input from external parties on camera deployment to maximize public safety and efficiency.

The high-definition, pan tilt zoom cameras have improved PG&E's overall situational awareness and have proven to be a valuable tool for assisting the WSOC, first responders, and fire agencies. Live feeds from cameras have often been featured on local newscasts. The cameras have near infrared capability to operate in low to no sunlight and are available via a web interface with time lapse functionality to assist with confirmation of fire reports, and monitoring fire progression and environmental conditions. First responders and external agencies such as CAL FIRE and the USFS have the ability to control PG&E's cameras (pan/tilt/zoom) to assist with their respective fire response efforts. Live feeds and time-lapse data from this camera network are available to the public at <http://www.alertwildfire.org>.

In Figure PG&E 5-12 below, PG&E provides an example camera output, web interface and camera network density.

FIGURE PG&E 5-12: EXAMPLE CAMERA OUTPUT, WEB INTERFACE, AND CAMERA NETWORK DENSITY FROM WWW.ALERTWILDFIRE.ORG



5.3.2.1.5 PG&E Fire Detection and Alert System (FDAS)

PG&E's Meteorology team deployed a fully operational state-of-the-art satellite-based fire detection and alerting system in 2019 and will continue to operate, leverage and enhance this system in 2020. As of January 1, 2020, the system ingested and reconciled fire detection data from 2 Geosynchronous Satellites (GOES-West, GOES-East), and 3 polar orbiting satellites (MODIS-AQUA, MODIS-TERRA, SUOMI-NPP). PG&E developed the system to incorporate new fire detection data feeds as they become available. PG&E is working directly with industry-leading fire detection algorithm developers and experts from the Space Science and Engineering Center (SSEC) at the University of Wisconsin-Madison to procure a customized feed of satellite fire detection data with the lowest latency available.

The new GOES-West and GOES-East satellites scan the entire CONUS each 5 minutes and thus provide new fire detection data each 5 minutes. The data pipeline with SSEC has been optimized to reduce data transfer and processing latency. New data is available to an analyst typically less than 10 minutes after the GOES spacecraft completes a scan. In addition, each satellite has 2 mesoscale sectors that scan a smaller area every minute. Fire detection data derived from the 1-minute imagery is available to PG&E whenever a mesoscale sector views all or a portion California.

To visualize and interact with the fire detection data, PG&E developed a proprietary application in-house that combines fire detection alerts as they arrive and disseminates alerts via an internal web-app and email. The fire alert and web application displays each location where fire was recently detected and PG&E meteorologists or analysts with the WSOC can quickly review live feeds from the nearest wildfire cameras to confirm fire and/or smoke in an area. The satellite data also contains a measure of the fire intensity called Fire Radiative Power (FRP), and the web-app allows the user to retrieve an FRP timeseries in order to track the intensity of fires in a given location. The application also displays current incidents available from CAL FIRE as well as fire perimeters from federal agencies. PG&E is actively sharing fire alerts with CAL FIRE through the CA National Guard and with numerous county and local fire departments. PG&E is open to sharing this data with interested stakeholders and to the general public. This tool helps the PG&E WSOC respond to new and emerging events quickly and make faster operational decisions.

For the 2020 fire season, PG&E plans to add NOAA-20 data into the suite of fire detection data. NOAA-20 is the first spacecraft of NOAA's new generation of polar satellites and carries the Visible Infrared Imaging Radiometer Suite (VIIRS), which has proven tool for fire detection. The VIIRS instrument is currently aboard the Suomi-NPP spacecraft. Beyond 2020, NOAA plans to launch 3 additional polar orbiting satellites in this new generational fleet and PG&E will incorporate their fire detection data if proven useful. PG&E may also evaluate adding other public and proprietary data sources as they become known or available.

Below PG&E provides example of: (1) output of the PG&E Fire Detection and Alert System (FDAS) (Figure PG&E 5-13); (2) fire detection alert email distributed automatically by the PG&E Fire Detection and Alert System (Figure PG&E 5-11); and (3) integration of PG&E wildfire cameras and the PG&E FDAS (Figure PG&E 5-12).

FIGURE PG&E 5-13: EXAMPLE OUTPUT OF THE PG&E FIRE DETECTION AND ALERT SYSTEM (FDAS) – SNAPSHOT TAKEN ~3:45 PM 9/9/2019 AND ACTIVE FIRE SHOWN IS THE WALKER FIRE – VIIRS AND MODIS FIRE DETECTIONS ARE NOT SHOWN

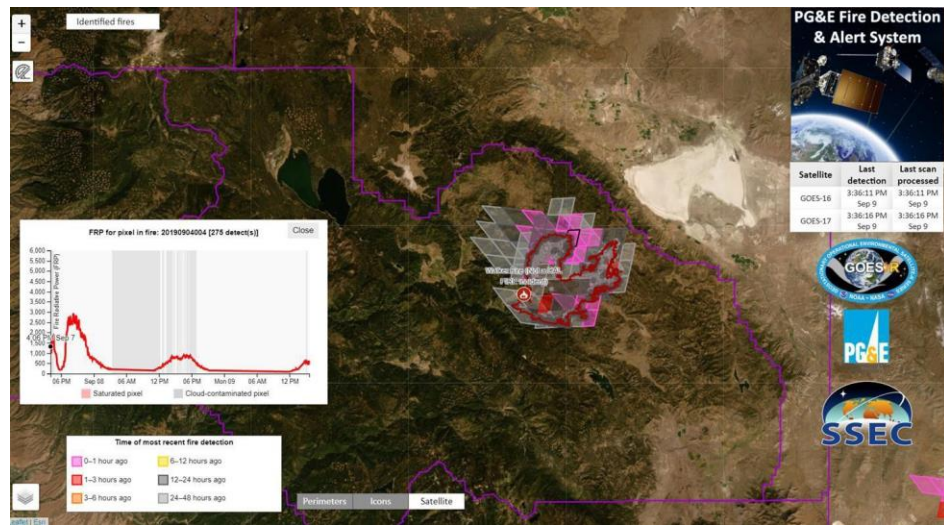


FIGURE PG&E 5-14: EXAMPLE FIRE DETECTION ALERT EMAIL DISTRIBUTED AUTOMATICALLY BY THE PG&E FIRE DETECTION AND ALERT SYSTEM – THIS INCIDENT WAS THE MARSH FIRE THAT WAS REPORTED IN CONTRA COSTA COUNTY ON AUGUST 3, 2019.

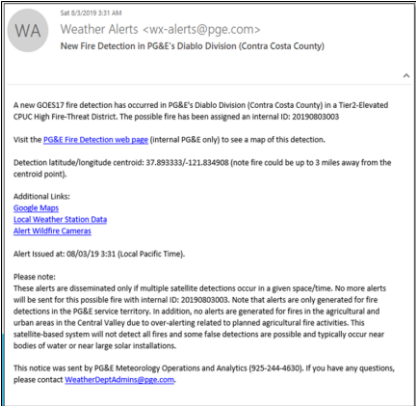


FIGURE PG&E 5-15: EXAMPLE INTEGRATION OF PG&E WILDFIRE CAMERAS AND THE PG&E FDAS –THIS EXAMPLE SHOWS A SMOKE PLUME VISIBLE FROM A FIRE DETECTED FROM FDAS
 – THIS EXAMPLE IS FROM THE FIRE THAT OCCURRED IN THE NUSTAR ENERGY FACILITY IN CROCKLETT, CA



5.3.2.1.6 Live Fuel Moisture Sampling

In 2019, PG&E worked with San Jose State University (SJSU) to sample Live Fuel Moisture (LFM) at multiple locations in the HFTD within the Bay Area. Data collected from SJSU is available here: <https://www.fireweather.org/fuel-moisture>. Live fuel moisture is a critical component of the FPI and fire spread modeling and is traditionally sampled in the field. The coverage of existing LFM sampling from state and federal agencies is lacking across the PG&E territory and there are many gaps in LFM data spatially and temporally. This leads to challenges in creating and calibrating LFM models that predict LFM for use in PG&E's FPI model at a granular level.

In addition to partnering with SJSU again in 2020, PG&E plans to conduct LFM sampling utilizing Safety and Infrastructure Protection Team (SIPT) resources. PG&E is targeting taking samples from an additional 10 locations by June 1, 15 additional sites by September 1, and 30 total sites by the 2021 fire season. LFM is expected to be sampled monthly at each site during fire season. The samples will be sealed and shipped to the PG&E Chemistry Laboratory (ISO 17025 accredited) for analysis. LFM results are planned to be uploaded to the USFS National Fuel Moisture Database (NFMD) for public use as long as the database is operational and maintained. The NFMD is available here: <https://www.wfas.net/index.php/national-fuel-moisture-database-moisture-drought-103>.

In 2020 and beyond, PG&E will attempt to obtain all LFM samples from state and federal agencies that are not being uploaded to the NFMD. Beyond 2021, PG&E will evaluate adding additional sites based on needs of the utility and industry. The goal of this program is to create a rich dataset for the fire community upon which LFM models can be constructed and calibrated. PG&E is open to working with external agencies to select sampling sites for maximum benefit.

5.3.2.1.7 Addressing Weather Forecast Model Uncertainty

To address uncertainty in weather forecast modeling PG&E employs multiple methods. First, PG&E leverages several sources of forecast model data and compares results to determine forecast alignment. For example, if all weather forecast models agree a certain weather event will transpire, then confidence is generally high. In Figure PG&E 5-16 below, PG&E employs tools to quickly compare pressure gradient forecasts and wind speeds from multiple sources of forecast data. Another method applied is ensemble prediction. PG&E leverages outputs and visualizations from the ECMWF Ensemble Prediction System (EPS), which is comprised of 50 model members. Figure PG&E 5-17 below shows the forecasted Arcata, CA to Santa Barbara, CA pressure differential from every ensemble member. This Arcata to Santa Barbara pressure differential is an important predictor of outage activity during winter storms while other pressure differentials have been found to be important predictors of other weather patterns. One can generally see very good alignment (thus good confidence) in the near-term forecast, following by increased dispersion in model solutions generally farther out in time. PG&E also leverages the ECM EPS for precipitation forecasting. An example image from an internal application developed by PG&E is presented below in Figure PG&E 5-18.

In 2020, PG&E also plans to deploy an in-house high-resolution model ensemble package that is based on the POMMS model. This package will include 8 model members that provide hourly forecasts at 2 km resolution across the PG&E territory. This will significantly increase the amount of forecast data generated daily near the surface from 100 million data points in 2019 to over 1 billion in 2020.

FIGURE PG&E 5-16: EXAMPLE OUTPUT FROM THE PG&E PRESSURE GRADIENT TRACKING TOOL THAT SHOWS OBSERVATIONS (BLACK DOTS) VERSUS PRESSURE GRADIENT FORECASTS FROM SEVERAL DETERMINISTIC FORECAST MODELS.

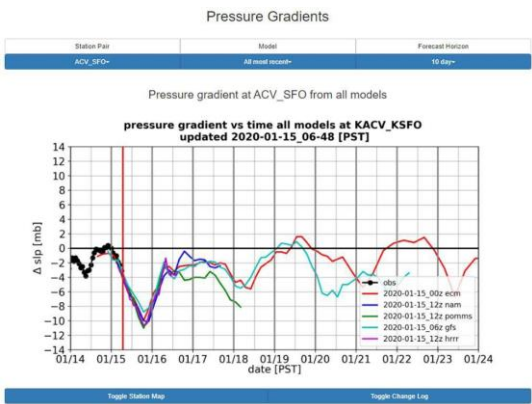


FIGURE PG&E 5-17: EXAMPLE OUTPUT FROM THE PG&E ECMWF ENSEMBLE PREDICITON SYSTEM (EPS) GRADIENT TOOL THAT SHOWS MODEL RESULTS FROM 50 EPS MEMBERS (GRAY LINES) THE TOP AND BOTTOM 10% (LIGHT BLUE SHADING), THE EPS MEAN (BLACK LINE) AND THE DETERMINISTIC ECMWF MODEL (RED LINE).

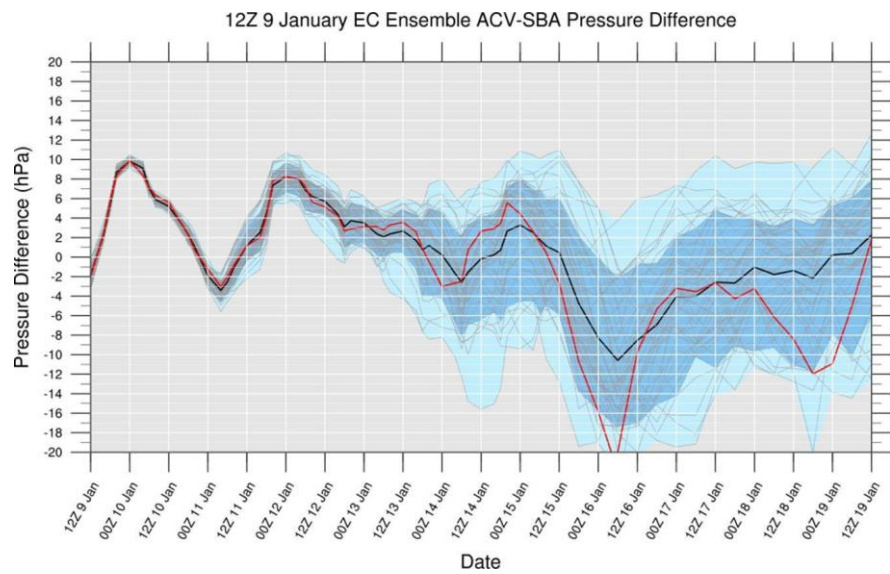
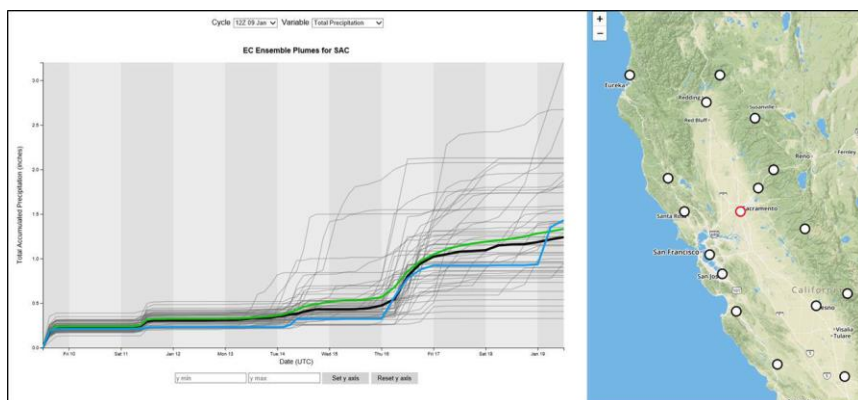


FIGURE PG&E 5-18: EXAMPLE OUTPUT FROM THE PG&E ECMWF ENSEMBLE PREDICTION SYSTEM (EPS) PRECIPITATION TOOL THAT SHOWS MODEL RESULTS FROM 50 EPS MEMBERS (GRAY LINES) THE EPS MEAN (GREEN LINE), THE EPS MEDIAN (BLACK LINE) AND THE DETERMINISTIC ECMWF MODEL (BLUE LINE).

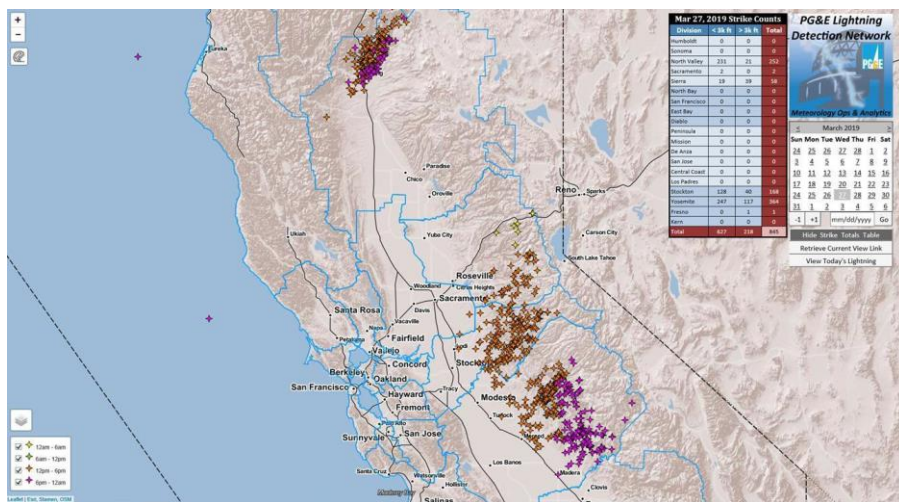


5.3.2.1.8 PG&E Lightning Detection Network (PLDN)

PG&E operates several lightning detection sensors that feed into a larger network: the Global Lightning Network. Cloud to ground lightning strikes can cause utility outages as well as result in fire ignitions. For example, from June 20 to 21, 2008 more than 20,000 lightning strikes occurred resulting in more than 2,000 fires. PG&E also developed a custom internal application that displays lightning strikes in real-time and allows a user to customize alerts received for just the area they are interested in. The application also gives the user the ability to see historical lightning as well as the peak lightning stroke amperage. PG&E plans to continue operating and maintaining lightning sensors deployed across the PG&E territory in 2020 and beyond. No major changes are anticipated at this time in the next 3-10 years.

In Figure PG&E 5-19 below, PG&E provides Example output from the PG&E Lightning Detection Network (PLDN) showing historical lightning from March 27, 2019.

FIGURE PG&E 5-19: EXAMPLE OUTPUT FROM THE PG&E LIGHTNING DETECTION NETWORK (PLDN) SHOWING HISTORICAL LIGHTNING FROM MARCH 27, 2019



5.3.2.1.9 Information Sharing

PG&E is committed to sharing weather, fire detection information, camera data and PSPS potential forecasts with stakeholders and the public. PG&E greatly values the role state, county and federal agencies (e.g., CAL FIRE, NWS, Predictive Services) play in communicating fire danger and risk to the general public. In 2019, several meetings were held with agencies and stakeholders to better align on how PG&E would share information with the public. PG&E currently shares the following information daily:

- Data collected from weather stations
- Live feeds from wildfire alert cameras
- Fire detection information with the CA National Guard, county and municipal fire agencies
- PG&E's 7-day PSPS forecast and discussion

In 2020 and beyond, PG&E expects to further participate with stakeholders to refine PG&E's data sharing practices with agencies, counties, other utilities and the public.

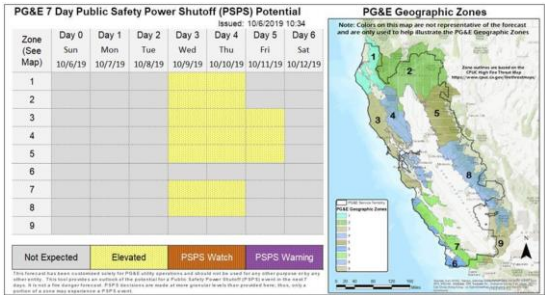
In 2019, PG&E wanted to provide the public with advanced awareness of upcoming conditions that may lead to potential for a PSPS event. PG&E developed and then operationally implemented a publicly available 7 day forecast on the potential of implementing PSPS. This forecast is published daily by an operational meteorologist or fire scientist from PG&E's Meteorology & Analytics team. The forecast is customized for PG&E utility operations and provides an overview for a potential PSPS event in the next 7 days as determined from an analysis of forecasted weather, the potential for wind-related damage, and fuel moisture content in dead and live vegetation. The forecast is broken down by broad PG&E Geographic Zones numbered 1 through 9; however, PSPS decisions are made at more granular levels with more detailed information shared with state, county and local officials as well as the public, once more detailed analysis is performed. The forecast is presented in one of four discrete categories for each geographic zone:

- Not Expected: Conditions that generally warrant a PSPS event are not expected at this time.
- Elevated: An upcoming event (typically a period of adverse weather combined with dry fuels) is being monitored for an increased potential of a PSPS event.
- PSPS Watch: The PG&E EOC is activated for a reasonable chance of executing PSPS to reduce public safety risk in a given geographic zone due to a combination of adverse weather and dry fuel conditions. A PSPS watch is typically only issued within 72 hours before the anticipated start of an event.
- PSPS Warning: The PG&E EOC is activated and customers in areas being considered for PSPS have been or are being notified. This level indicates execution of PSPS is probable given the latest forecast of weather and fuels and/or observed conditions. PSPS is typically executed in smaller and more targeted areas than the

PG&E Geographic Zones. This level does not guarantee a PSPS execution as conditions and forecasts may change.

Figure PG&E5-20 below provides an example of a PSPS forecast.

FIGURE PG&E 5-20: EXAMPLE OF A PSPS FORECAST ISSUED ON 10/6 FOR AN UPCOMING PERIOD OF FIRE RISK ON 10/9-10/11



In 2020 and beyond, PG&E expects to further participate with stakeholders to refine PG&E's data sharing practices with agencies, counties, municipalities, other utilities and the public.

5.3.2.1.10 Collaborative Efforts to Advance Fire Science

PG&E has partnered with SDG&E and SCE in collaborative efforts to help advance fire science. The utilities are working with external experts as well as the SJSU Fire Weather Research Lab to define areas where additional research is needed in the fire science field. In 2020 and beyond, the utilities are expected to fund joint research projects with external experts as well as the SJSU Fire Weather Research Lab as well as potentially fund a post-doctoral position at SJSU focused on areas that benefit the entire utility-fire science field. These efforts are expected to yield benefit for not only utilities in California, but other utilities across the western United States and potentially the world, where there is a risk of utility-related fire risk.

In Q2 2020, PG&E plans to present to students and faculty at SJSU about utility-weather and utility-fire risk to further foster a collaborative partnership as well as hopefully energize the next generation of utility fire scientists and meteorologists. PG&E is open to hosting and participating with other universities in this regard, as well as sharing data to help catalyze fire science advancements.

Progress Timeline

1. Before the upcoming wildfire season:

- Weather prediction using cloud computing: Develop next version of POMMS
- Wildfire spread models: Simulate over a billion fires across historically high fire potential days
- Weather stations: Use weather station data to help forecast and monitor for high fire risk weather conditions.
- Wildfire cameras: Deploy approximately 200 additional weather cameras by December 31, 2020
- PG&E fire detection and alert system: Implement fire detection and alert system operations as described above.
- Live fuel moisture sampling: Partner with SJSU to conduct LFM sampling
- Addressing weather forecasting model uncertainty: Continue to evaluate weather forecasting models and identify potential improvements.
- PG&E lightning detection network: Operate and maintain lightning sensors as described above.
- Information sharing: Continue to interact with stakeholders to improve and refine data sharing practices with agencies, counties, other utilities and the public.
- Collaborative efforts to advance fire science: Work collaboratively with other utilities and partners to advance fire science.

2. Before the next annual update:

- Weather prediction using cloud computing: Create historic climatology data stack at 2km resolution
- Wildfire spread models: Enhance model framework including data inputs, fire consequence outputs and metrics
- Weather stations: Continue to use weather station data to help forecast and monitor for high fire risk weather conditions.
- Wildfire cameras: Deploy approximately 200 additional weather cameras by December 31, 2020
- PG&E fire detection and alert system: Add NOAA-20 data into the suite of fire detection data
- Live fuel moisture sampling: Partner with SJSU to conduct LFM sampling
- Addressing weather forecasting model uncertainty: Deploy an in-house high-resolution model ensemble package to significantly increase amount of forecast data generated daily.
- PG&E lightning detection network: Operate and maintain lightning sensors as described above.
- Information sharing: Continue to interact with stakeholders to improve and refine data sharing practices with agencies, counties, other utilities and the public.
- Collaborative efforts to advance fire science: Along with other utilities, fund joint research project with external experts and the SJSU Fire Weather Research lab to benefit the utility fire science field.

3. Within the next 3 years:

- Weather prediction using cloud computing: Evaluate 2km model forecasts and apply lessons learned
- Wildfire spread models: Identify areas for improving models and incorporate lessons learned.
- Weather stations: Continue to use weather station data to help forecast and monitor for high fire risk weather conditions.
- Wildfire cameras: Deploy cameras to cover approximately 90 percent of the high fire-risk areas
- PG&E fire detection and alert system: Evaluate data from additional NOAA polar orbiting satellites and incorporate into fire detection data if proven useful

- Live fuel moisture sampling: Create database of LFM sampling data from state and federal agencies for the fire community
- Addressing weather forecasting model uncertainty: Continue to evaluate weather forecasting models and identify potential improvements.
- PG&E lightning detection network: Operate and maintain lightning sensors as described above.
- Information sharing: Continue to interact with stakeholders to improve and refine data sharing practices with agencies, counties, other utilities and the public.
- Collaborative efforts to advance fire science: Along with other utilities, fund joint research project with external experts and the SJSU Fire Weather Research lab to benefit the utility fire science field.

4. Within the next 10 years:

- Weather prediction using cloud computing: Continue to evaluate and improve modeling capabilities using state of the art technology
- Wildfire spread models: Continue to evaluate and improve modeling capabilities using state of the art technology
- Weather stations: Continue to use weather station data to help forecast and monitor for high fire risk weather conditions.
- Wildfire cameras: Reassess the camera network coverage, including coordinating coverage with other agencies.
- PG&E fire detection and alert system: Evaluate adding additional public or proprietary data sources
- Live fuel moisture sampling: Continue to update LFM database for use in constructing and calibrating LFM models.
- Addressing weather forecasting model uncertainty: Continue to evaluate weather forecasting models and identify potential improvements.
- PG&E lightning detection network: Operate and maintain lightning sensors as described above.
- Information sharing: Continue to interact with stakeholders to improve and refine data sharing practices with agencies, counties, other utilities and the public
- Collaborative efforts to advance fire science: Continue to identify ways to work with partners to advance fire science

5.3.2.2 Continuous Monitoring Sensors

5.3.2.2.1 Electric Transmission

Line monitoring non-tripping travelling wave relays (SEL T400L's) are being installed on selected transmission lines to capture high frequency travelling waves emitted by faults or other electric system anomalies (high corona). System Protection, along with the relay vendor, is evaluating the relay data to determine if vulnerable locations along the transmission line can be identified prior to the condition evolving into a bolted fault. This pilot effort began in the summer of 2019 and has not yet produced any actionable incipient fault data.

5.3.2.2.2 Electric Distribution

PG&E is evaluating, deploying, and operating technologies/applications that provide data for real time continuous sensor monitoring and analytics of asset health and performance. The data from this sensor monitoring could be used to predict developing problems on the electric distribution system so PG&E can implement proactive maintenance, thereby reducing potential hazards and improving public safety. Expert Engineers, Data Scientists, and Field Operations are involved with several initiatives supporting wildfire mitigation efforts.

5.3.2.2.3 SmartMeter™ Partial Voltage Detection (Formerly Known as Enhanced Wires Down Detection)

PG&E has enabled Single-Phase SmartMeters™ to send real-time alarms to the Distribution Management System under partial voltage conditions (25-75 percent of nominal voltage). Prior to implementation, SmartMeters™ could only provide real-time alarms for the outage state. For Three-Wire distribution systems, the partial voltage condition indicates one phase feeding the transformer has low voltage or no voltage. Energized or de-energized wires down will create a low voltage condition on transformers through the mechanism of transformer back feed from the inactive phase to the fault. This enhanced situational awareness can help detect and locate downed distribution lines more quickly to enable faster response. Faster response may not only reduce the amount of time the line is down but may also allow first responders to more quickly extinguish wire down-related ignitions if they occur. To date, partial voltage detection capability has been deployed to approximately 4.5 million SmartMeters™ covering 25,597 line miles of Tier 2 and Tier 2+ HFTD areas. In 2020, PG&E has already initiated plans to continue developing this solution to extend the partial voltage detection enhancement to Three-Phase SmartMeters™ and 4-Wire distribution systems.

Progress Timeline

- 1. Before the upcoming wildfire season:** Before the upcoming wildfire season:
No additional deployment is planned before the upcoming wildfire season this year.
- 2. Before the next annual update:** PG&E will deploy to an additional 365,000 Three-Phase SmartMeters™ covering up to 25,597 Line-miles of Tier 2 and Tier 3 HFTD areas with 4-Wire Distribution.
- 3. Within the next 3 years:** See above.
- 4. Within the next 10 years:** See above.

5.3.2.2.4 Distribution Fault Anticipation Technology

Distribution Fault Anticipation (DFA) technology captures primary distribution disturbance current and voltage waveforms. It conducts digital signal processing locally, communicates results to a waveform classification engine which then identify both normal and abnormal events on the distribution system. The DFA technology is installed within the substation and uses existing substation bus PTs and circuit breaker CTs.

DFA technology is being evaluated on 6 distribution feeders covering 718 line miles. These installations are part of PG&E's EPIC 2.34 and have a primary objective of validating the performance of the early fault detection (EFD) sensors in capturing disturbance and arcing events. A second objective is to evaluate the DFA sensor for use with wildfire risk management and operational needs. To date there have been over 23,000 disturbance events captured. Of these events, 6.4% are considered abnormal events (overcurrent fault, capacitor restrike, arcing). Of the total number of abnormal events 11.2% have been identified as arcing. This EPIC project is to be completed in July of 2020. Prior to project completion, PG&E will conduct a full comparative and strategic assessment of the technology. Potential further deployment will be determined at that time.

Progress Timeline

1. ***Before the upcoming wildfire season:*** No additional deployment is planned.
2. ***Before the next annual update:*** See above.
3. ***Within the next 3 years:*** See above.
4. ***Within the next 10 years:*** See above.

5.3.2.2.5 Early Fault Detection

EFD Sensors are also being evaluated on one 12kV electric distribution feeder covering 120 line miles. During a July 2018 Wildfire Safety benchmarking trip, PG&E learned of EFD sensor technology from a vendor in Australia. The sensors detect Radio Frequency (RF) emissions generated by partial discharge activity on the distribution feeder. The sensors are deployed on distribution poles at up to 3-mile spacing to cover the mainline and significant branches of the feeder. The sensors work in pairs to monitor the distribution lines between them and use time-of-flight proportionality to distance to determine the location of partial discharge emissions between each sensor pair. In various use cases at PG&E and other utilities, the EFD sensors have demonstrated detection of incipient faults such as failing transformers, eminent poles fires, conductor strand breaks, and vegetation arc pruning. This pilot is also included in PG&E's EPIC 2.34 that is scheduled for completion in July of 2020. Prior to completion, PG&E will also conduct a strategic assessment of the technology. Potential further deployment will be determined at that time.

Progress Timeline

1. ***Before the upcoming wildfire season:*** Additional part of one 21kV feeder is planned be equipped with the sensors.
2. ***Before the next annual update:*** See above.
3. ***Within the next 3 years:*** See above.
4. ***Within the next 10 years:*** See above.

5.3.2.2.6 Sensor IQ

PG&E is piloting Sensor IQ on approximately 500K SmartMeters™ in HFTD areas and customizing reads and alarms to identify service transformer failures, with other use-cases to be considered based on wildfire risk reduction and/or business value. [SSN is being contracted to implement Sensor IQ, which allows for a parallel, more granular data path \(outside of billing\) to support distribution asset analytics use cases. Deployment enables customizable Network Interface Card \(NIC\) data sampling, read jobs, and alarms.](#)

The data collected through Sensor IQ is critical for a variety of other wildfire related initiatives, including: (i) Rapid Earth Fault Current Limiter which requires feeder phasing to determine the line-earth capacitive imbalance; (ii) increasing the data collected (voltage, current, power factor) and increasing the frequency of data collection will improve wires down algorithms to find faults. Prior to completion of the pilot, PG&E will conduct a strategic assessment of the technology. Potential further deployment and applications will be determined at that time.

Progress Timeline

1. ***Before the upcoming wildfire season:*** Sensor IQ pilot will be deployed to 500K SmartMeters™ covering approximately 25,597 distribution line miles.
2. ***Before the next annual update:*** See above.
3. ***Within the next 3 years:*** See above.
4. ***Within the next 10 years:*** See above.

5.3.2.2.7 Line Sensor Devices

Building from its Smart Grid Pilot programs, PG&E began the deployment of 333 line sensing devices on 14 key circuits within PG&E's North Bay Tier 2 and Tier 3 HFTD areas with a focus on reducing wildfire risk and improving public safety by continuous, real-time monitoring of the grid, performing analytics on captured line disturbance data, identifying potential hazards, and when necessary dispatching field operations to proactively patrol/maintain/repair discovered field conditions or assets on the verge of failure.

Line sensors are primary conductor-mounted devices that continuously measure current in real-time and report events as they occur, and in some cases the current waveform of grid disturbances. These line sensors are next-generation fault indicators (covered in Section 5.3.2.3 below) with additional functionality and communication capabilities.

In 2019, PG&E began to operationalize the use of line sensors to proactively monitor and locate distribution grid disturbances and analyze when to dispatch field inspectors. PG&E is using data provided by line sensor technologies to bolster asset health and performance through a three step process: (i) Collecting line sensor data attributes on disturbances to create a database of disturbance signatures for disturbance evaluations; (ii) Detecting disturbance information from Tier 2 and Tier 3 HFTD areas on PG&E's electric distribution circuits and matching the captured disturbance data against the signature database to determine if a distribution line risk is likely to materialize as a hazard; (iii) Matching line sensor data attributes on line risks in a manner in which they can be evaluated in the distribution network model (CYME Power Engineering software) to estimate the location of the line risk for proactive field patrol, inspection, and repair, if necessary, before failure to reduce risk and improve system safety.

Using an engineering approach, PG&E continues to identify additional circuits in Tier 2 and Tier 3 HFTD areas and will be redesigning an optimal line sensor device footprint to further support wildfire mitigation. PG&E will strategically deploy, gain further experience, and operate state-of-the-art systems and technologies to continuously monitor the grid and analyze data to prevent asset failures and reduce risk. In parallel, it will continue to benchmark other leading utilities and manufacturers to learn alternatives and/or to improve the company's predictive analytics and preventative operational practices as well as to continuously evaluate new and/or emerging technologies.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E plans to deploy line sensors to approximately 20 feeders covering up to 3,000 line miles.
2. **Before the next annual update:** See above.
3. **Within the next 3 years:** PG&E is planning and may potentially deploy line sensors to approximately 120 to 240 feeders covering up to 12,000 miles.
4. **Within the next 10 years:** See above.

5.3.2.2.8 Distribution Arcing Fault Signature Library

PG&E is partnering with two of the national laboratories to install a high-fidelity optical sensor technology on a distribution feeder for the completion of a Distribution Arcing Fault Signature Library. The optical sensors, with immunity to electromagnetic interference and instrument transformer saturation, will provide high frequency sampling of voltage, current, temperature, pressure, vibration, and acoustic variables. The Distribution Arcing Fault Signature Library will inform PG&E about the types and resolutions of sensors needed to detect incipient fault conditions on the distribution system and intervene with proactive maintenance to reduce wildfire risks. Prior to completion, PG&E will also conduct a strategic assessment of the technology. Potential further deployment and applications will be determined at that time.

Progress Timeline

1. **Before the upcoming wildfire season:** See above.
2. **Before the next annual update:** PG&E plans to install at 1 distribution feeder that will cover approximately 201 Line-Miles.
3. **Within the next 3 years:** See above.
4. **Within the next 10 years:** See above.

5.3.2.3 Fault Indicators for Detecting Faults on Electric Lines and Equipment

5.3.2.3.1 Electric Transmission

Other than the travelling wave devices referenced in "Continuous Monitor Sensors", Transmission has no future plans to install equipment dedicated to "Fault Indication" that is not directly associated with Protective System Relays that tripped the faulted element.

5.3.2.3.2 Electric Distribution

PG&E has installed nearly 4,400 overhead fault indicators throughout the distribution system to improve restoration time after an outage. Overhead fault indicators are a valuable tool that assist troubleshooters in locating the faulted section of line so the faulted section of line can be isolated and customers restored. PG&E does not have a program to install additional fault indicators in fire areas for future years. Instead, PG&E's focus will be piloting sensor technologies with centralized advanced algorithms to detect problems before failure.

Progress Timeline (for both transmission and distribution)

1. ***Before the upcoming wildfire season:*** See above.
2. ***Before the next annual update:*** See above.
3. ***Within the next 3 years:*** See above.
4. ***Within the next 10 years:*** See above.

5.3.2.4 Forecast of a Fire Risk Index, Fire Potential Index, or Similar

The PG&E FPI is used as a daily and hourly tool to drive operational decisions to reduce fire risk. FPI informs the PSPS program and informs daily operational actions to reduce the risk of fire ignition per company standards. Some of these daily actions include disabling of reclosing devices and placing restrictions on higher risk field activities such as welding. Until December 31, 2014, PG&E received daily fire danger ratings from CAL FIRE for each Fire Index Area across PG&E's service territory. CAL FIRE discontinued this support in 2015. Starting in 2015, PG&E leveraged high-resolution model outputs from POMMS and the National Fire Danger Rating System to derive fire danger ratings across the PG&E territory for daily operational actions. PG&E benchmarked and worked with other utilities and experts in fire danger rating to improve core inputs of the model in 2016, 2017 and 2018.

In 2019, PG&E leveraged a newly developed 30-year weather and fuels climatology at 3 km to recalibrate the FPI model that was eventually utilized during the 2019 fire season. PG&E's data scientists sought to capture the largest drivers of large fire growth. In order to accomplish this task, PG&E leveraged a USFS fire occurrence dataset with thousands of fires and combined these fires with the hourly climatology to determine weather and fuel conditions present during each incident. As there are many fire danger components and indices and data sources available and discussed in the academic literature and utilized by other utilities, PG&E sought to develop the most representative FPI for its service territory by testing thousands of FPI model combinations and evaluating several machine learning techniques. Ultimately, PG&E built and evaluated over 4,000 combinations of the FPI model using numerous weather components, fire weather indices (Fosberg Fire Weather index, the Hot-Dry-Windy Index, the Santa Ana Wildfire Threat weather index), outputs from NFDRS, Nelson DFM model, a machine-learning derived LFM model, and 'containment' and 'land characteristic' features such as road density, distance to nearest fire station and land-use type among several others.

The FPI that PG&E selected and deployed for operational use in the 2019 fire season combines wind speed, temperature, relative humidity, dead fuel moisture, live fuel moisture and fuel type into an index that represents the probability for small fires to become large incidents. The FPI model is run on the same 3-km resolution dataset as the high-resolution weather and OPW model. The FPI model output is available in a web application that allows an analyst to review the data hourly for any geographic area. The hourly data are also available in Google Earth, which the analyst can overlay with other asset layers. For day to day operational decisions, the FPI data are also aggregated to the Fire Index Areas. Maps and data available in GIS formats are available for the next three days via a web application. See Figure PG&E 5-21 below.

PG&E also developed a wildfire danger console to help track and monitor numerous components that comprise the PG&E FPI. See Figure PG&E 5-23 below. This gives the analyst a snapshot of the current state of weather and fuels, as well as the daily maximum outage probability and fire potential. Hourly dead fuel moisture observations are harvested and displayed from the RAWWS weather network available across the state and the LFM dashboard presents the latest readings available in the National Fuel Moisture Database. PG&E has also automated Family Plus (FF+), which produces National Fire Danger Rating System (NFDRS) outputs. Family Plus (FF+) is a software

suite developed by the USFS and used to calculate fuel moistures and indices from the US NFDERS using hourly or daily fire weather observations primarily from RAWWS. Family Plus (FF+) is heavily used by local, state and federal agencies to assess fire danger components compared to historical data. PG&E automatically computes several NFDERS components using FF+ for 9 geographic regions across its service territory. The FF+ outputs serve as another fire danger gauge analysts utilize to assess fire danger and the general progression of fire season but are not used directly in the PG&E FPI.

By September 1, 2020, PG&E plans to recalibrate the FPI using the new climatology at 2 km resolution. In addition, PG&E plans to improve the USFS and CAL FIRE's fire occurrence dataset used as many data quality issues and potential enhancements were noted during the 2019 analysis (e.g., wrong fire location, missing fires). PG&E is also evaluating partnering with external experts and/or utilizing remote sensing techniques to enhance the fire occurrence datasets. In addition to improving fire occurrence, PG&E is also planning to improve the quality and granularity of the input weather and dead fuel moisture data and is working with external experts to improve LFM data using remote sensing and/or machine learning capabilities. PG&E is open to sharing daily FPI data with interested stakeholders but greatly values the role state and federal agencies play in communicating fire danger and risk to the general public. As a result, PG&E's data sharing strategy centers not on communicating the fire potential, but rather the potential for executing PSPS. In 2020 and beyond, PG&E is open to working directly with external stakeholders to refine how information in this area is shared and distributed.

Progress Timeline (for both transmission and distribution)

1. ***Before the upcoming wildfire season:*** PG&E will be in the process of recalibrating the FPI using new climatology at 2km resolution and improve the USFS and CAL FIRE occurrence datasets.
2. ***Before the next annual update:*** PG&E plans to complete recalibrating FPI and improving fire occurrence datasets.
3. ***Within the next 3 years:*** Continue to improve the quality and granularity of input weather and dead fuel data.
4. ***Within the next 10 years:*** Continue to evaluate and improve FPI models and input data.

FIGURE PG&E 5-21: EXAMPLE OUTPUT FROM THE PG&E UTILITY FIRE POTENTIAL INDEX WEB APPLICATION

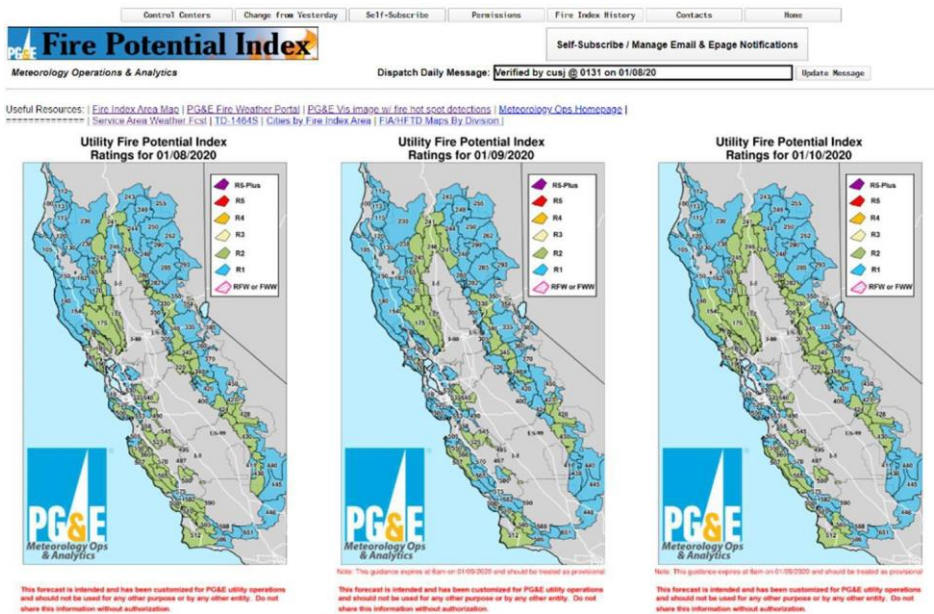


FIGURE PG&E 5-22: EXAMPLE OUTPUT FROM THE PG&E WILDFIRE DANGER CONSOLE

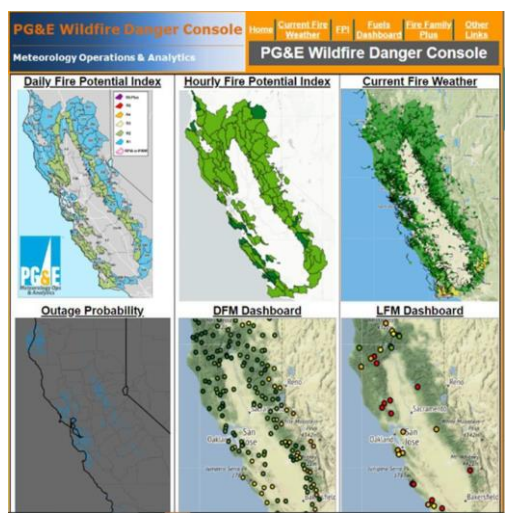
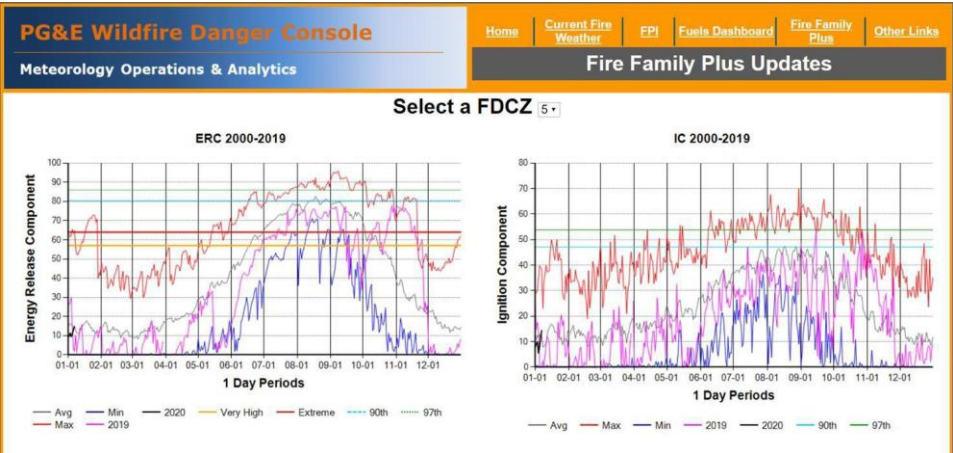


FIGURE PG&E 5-23: EXAMPLE OUTPUT FROM THE PG&E WILDFIRE DANGER CONSOLE – FIRE FAMILY PLUS AUTOMATED UPDATES



5.3.2.5 Personnel Monitoring Areas of Electric Lines and Equipment in Elevated Fire Risk Conditions

5.3.2.5.1 Safety and Infrastructure Protection Team

Safety and Infrastructure Protection Teams (SIPT) consist of two-person crews composed of IBEW-represented employees who are trained and certified safety infrastructure protection personnel. They provide standby resources for PG&E crews performing work in high fire hazard areas, pre-treatment of PG&E assets during an ongoing fire, fire protection to PG&E assets, and emergency medical services.

Senate Bill 901 directed that electrical corporations:

"...shall make an effort to reduce or eliminate the use of contract private fire safety and prevention, mitigation, and maintenance personnel in favor of employing highly skilled and apprenticed personnel to perform those services in direct defense of utility infrastructure in collaboration with public agency fire departments having jurisdiction."

As a result, PG&E elected to establish in-house fire protection services. With the assistance of the Public Safety Specialists (PSS) Team, planning for the program started in December of 2018 and the first management employee was hired in March 2019. By May 2019, the SIPT team consisted of 63 field employees, 1 Manager, 3 supervisors, and 2 clerks. During the establishment of the program, PG&E employees

- Developed a custom SIPT engine design based on existing PG&E fleet vehicle;
- Designed custom built pumps capable of applying fire retardant;
- Acquired and outfitted temporary engines;
- Specified and acquired firefighting tools, radios, and personal protective equipment;
- Developed software applications for monitoring SIPT resource locations, scheduling and documenting work activities;
- Developed a three-week new employee training program and adopted procedures to ensure maintenance of EMT certification;
- Established routine and emergency operational procedures; and,
- Implemented a comprehensive change management program to integrate SIPT team with PG&E's field operations

SIPT crews also support PSPS zone generation sites by patrolling overhead sections of re-energized lines. This responsibility is expected to grow, as PG&E expands generation capabilities.⁹

⁹ SIPT resources are also discussed in Sections 5.3.6.2 and 5.3.6.6.

5.3.2.5.2 Data collection

SIPT crews are used to gather critical data to help PG&E prepare for and manage wildfire risk. When PG&E activates for a PSPS event, it deploys the SIPT teams to collect valuable weather and fuel data and report this information to the WSOC. With input from Meteorology, the WSOC makes decisions related to resourcing and location of Field Observers. The SIPT crews will be sent to specific locations within the Fire Index Area generally within a PSPS targeted zone. The number of field observers will vary depending on the total number of miles, surrounding terrain, facility attributes, and quantity of PSPS Zones within a FIA.

Real-time field observations are made to provide information about weather conditions on potentially impacted PSPS circuits. The SIPT crews will be in position prior to the forecasted PSPS event start and end times.

On-the-ground, real-time field observations are conducted to provide qualitative information (for example, flying debris, trees/branches down, conductor movement) about the presence of R5-Plus conditions potential and the possible need to trigger a PSPS event sooner than expected and provide information to support "all clear" conditions necessary to authorize patrol and restoration activities.

Observers will note hazards related to wind conditions, which may lead to outages. Field Observers record observations including date/time and location specifics about the following conditions:

- Trees / branches movement;
- Flying debris;
- Conductor movement; and,
- Wind speed.

In the EOC, the WSOC Lead and Specialist will review incoming documentation and determine if conditions warrant additional field observation or immediate consideration of PSPS.

SIPT crews are also utilized to collect localized live fuel moisture data to help PG&E make more informed operational decisions. The fuel data will inform PG&E Meteorology's FPI model. Furthermore, SIPT will utilize weather data and local condition to calculate "Ignition Potential" based on existing firefighting standards. See Section 5.3.2.1 for further information on PG&E's forecasting and estimating impacts (fire spread modeling, OPW model, SOPP).

Progress Timeline (for SIPT and data collection)

1. **Before the upcoming wildfire season:** Update and stabilize the current technology solutions and processes and increase staffing levels to support fire prevention and mitigation activities. Targeted staffing levels and associated equipment needs: 98 SIPT Crew members, 40 Engines.
2. **Before the next annual update:** See above.
3. **Within the next 3 years:** Continue to assess effectiveness of program and develop risk informed business case to potentially increase staffing levels and equipment needs.
4. **Within the next 10 years:** See above.

5.3.2.6 Weather Forecasting and Estimating Impacts on Electric Lines and Equipment

Unplanned outages can pose a fire ignition risk when surface fuels are extremely dry. When strong winds and dry conditions are present, the risk of fast spreading and catastrophic wildfire increases. The SOPP Model, a storm outage prediction system developed, maintained, and operated by the Meteorology team on behalf of Electric Emergency Management, is the primary tool PG&E uses to mitigate operational risk from adverse weather events that create a high volume of unplanned outages.

Functionally, the SOPP Model is a collection of tools, techniques and utility subject matter expertise that are employed to predict unplanned outage activity. In 2019, PG&E's meteorologists and data scientists developed the Dynamic Pattern and Analog Matcher (DPAM) tool that automatically matches GFS forecasts for the next 7 days against the North American Regional Reanalysis (NARR) from January 1995 through July 2019. DPAM dynamically utilizes seven atmospheric fields: 500- and 700-hPa geopotential height, 250- and 500-hPa winds, 700-hPa temperature, precipitable water, and sea-level pressure to return the top 20 historical weather days and the outage pattern on those days. These days can be studied in more detail by a PG&E meteorologist to help craft the SOPP outage forecast.

In 2019, PG&E also developed the OPW model, that is based on PG&E's outage history and 30-yr climatology. PG&E's OPW model is location specific and translates a forecasted wind speed from the PG&E POMMS model into frequency that represents the outage activity in the vicinity at that wind speed. Generally, as wind speeds increase, the historical frequency of outages increases. The OPW model was built using PG&E unplanned outage data from 2008 – 2018 and PG&E's high-resolution climatology model, which contains 30 years of hourly wind data at a 3 km spatial resolution. The wind-outage response was found to be heterogeneous across PG&E's territory due to varying vegetation, climatological wind exposure, and topography among other factors. The same OPW model and configuration used to construct the weather climatology is used in forecast mode to produce hourly and daily OPW forecasts. This consistency between historical and forecast data is key as wind outage correlations found in the historical data can be applied in forecast mode. The OPW model produces hourly forecasts at 3 km resolution. PG&E also developed an internal web application that allows the analyst to view each forecast hour in an interactive display. The application also simulates wind trajectories utilizing WebGL API. The application also has functionality to view previous forecasts as well as display an OPW time series of the latest 4 forecasts to help analyze forecast drift (i.e., weakening or strengthening). An example image is presented below in Figure PG&E 5-24. The web application can also display the FPI forecast and the product of FPI and OPW.

In 2020, once the new 30-year climatology is complete at 2 km, PG&E plans to recalibrate the OPW model to run at 2 km resolution and will also investigate methods to aggregate the model to the circuit or sub circuit level. Beyond 2020, PG&E plans to employ the latest weather models and data available to continuously improve the SOPP model.

Progress Timeline

1. ***Before the upcoming wildfire season:*** Conduct weather forecasting and impacts on electric lines and equipment as described above.
2. ***Before the next annual update:*** Recalibrate the OPS model to run at 2km resolution.
3. ***Within the next 3 years:*** Investigate methods to aggregate the model to the circuit or sub-circuit level. Continue to employ the latest weather models and data available to continuously improve the SOPP model.
4. ***Within the next 10 years:*** Continue to employ the latest weather models and data available to continuously improve the SOPP model.

FIGURE PG&E 5-24: EXAMPLE OUTPUT AND HOURLY VISUALIZATION OF THE PG&E OPW MODEL BASED ON POMMS

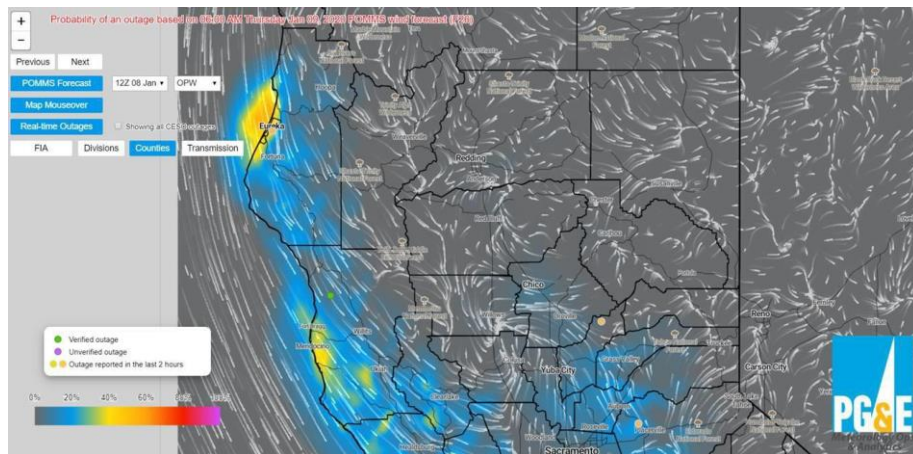
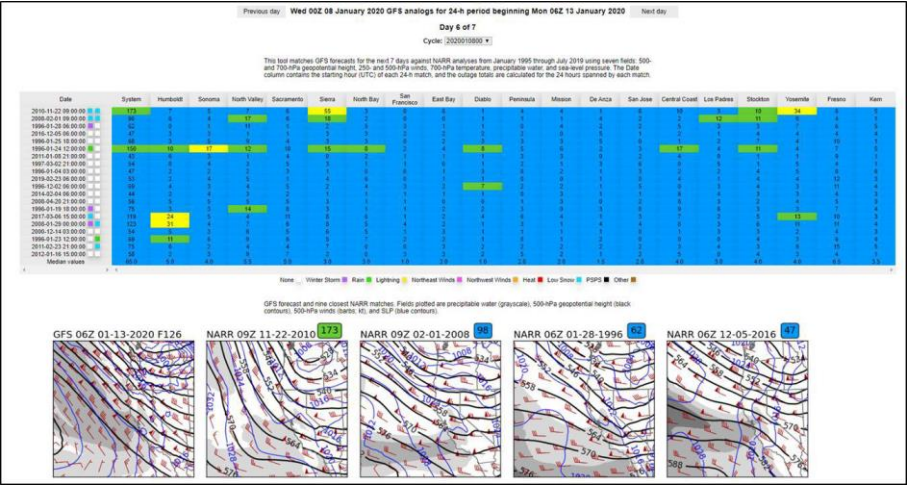


FIGURE PG&E 5-25: EXAMPLE OUTPUT FROM THE DYNAMIC PATTERN AND ANALOG MATCHER (DPAM) TOOL DEVELOPED BY PG&E USING GRS AND NARR ARCHIVE DATA



5.3.2.7 Wildfire Safety Operations Center (WSOC):

PG&E's WSOC is a physical facility that serves as the central wildfire-related information hub for PG&E, and monitors, assesses, and directs specific wildfire prevention and response efforts throughout its service area. The WSOC interfaces and collaborates with all PG&E LOBs and to assist in the deployment of technology, processes and procedures directly related to wildfire prevention, response, and recovery. The WSOC monitors for fire ignitions across PG&E's service area in real time, leveraging PG&E weather information, wildfire camera data, and publicly available weather information, as well as first responder and local and state data. Information also comes into the WSOC from PG&E field personnel, including PSS and SIPT Crews. Based on meeting established thresholds (e.g., fire proximity to PG&E assets) the WSOC will create and distribute incident report updates via email. This email includes wildfire status, PG&E assets threatened or involved, current red flag status, and fire weather information. The WSOC will send the report to a pre-determined internal distribution list including field staff, control center personnel, executive staff, supporting LOBs and other PG&E emergency responders.

The WSOC established notification protocols for communicating fire threat information to the various operations centers within PG&E (Gas Control, Electric Grid Control, Electric Distribution Control, IT/telecom, security, power generation, etc.). The real-time risk information communicated to internal control centers enables PG&E to act swiftly to protect life and property from fires threatening PG&E assets. These notifications also facilitate sharing of critical incident information in order to effectively respond to fire threats in coordination with other PG&E lines of business and external emergency response agencies.

The broader WSOC Organization also includes the PSS Team. The WSOC coordinates with PG&E's PSS team, who interfaces with CAL FIRE, federal fire agencies and other agency having jurisdiction (AHJ) incident commanders to oversee the organizational response to wildfire threats and incidents. The PSS team is responsible for gathering and sharing critical and fire PG&E infrastructure intelligence with the AHJs and WSOC. This information is used to inform PG&E deployment of additional resources needed to support fire mitigation and asset protection activities.

Progress Timeline

1. **Before the upcoming wildfire season:** Improve processes, procedures and technology based on lessons learned identified during 2019 Fire/PSPS season.
2. **Before the next annual update:** Identify critical elements of information and key internal and external stakeholders for the sharing of data and situational awareness information.
3. **Within the next 3 years:** Gain business case approval to expand to an All Hazards Monitoring Center that aligns with the State Warning Center and the State's newly forming Wildfire Forecast and Threat Intelligence Center per SB 209.
4. **Within the next 10 years:** See above.

5.3.3 Grid Design and System Hardening

Describe utility approach to the following categories of maintenance of transmission lines, distribution lines, and equipment, respectively:

- 1. Routine maintenance programs and protocols (i.e., covering general maintenance approach and programmatic structure),
- 2. Non-routine maintenance, further delineated into:
 - a. Emergency response maintenance/repair, and
 - b. Inspection response maintenance/repair.

1. Routine Maintenance:

PG&E's preventive maintenance approach aligns to Utility Operations Policy 3-7, "Gas and Electric Operation, Maintenance, and Construction," Utility Standard TD-1001S, "Electric Transmission Line Inspection and Preventive Maintenance Program" and the requirements of California Public Utilities Commission (CPUC) General Order GO 165 "Inspection Requirements for Electric Distribution and Transmission Facilities", as well as relevant portions of GO 95 "Rules for Overhead Electric Line Construction" and GO 128 "Rules for Construction of Underground Electric Supply and Communication Systems." These maintenance protocols reduce the potential for component failures and facilitate a proactive approach to repairing or replacing abnormal components.

2. Non-Routine Maintenance:

- a. Emergency Response maintenance/repair

Electric emergencies are created when outages occur and require immediate response by PG&E to restore customer service and protect the community from potential safety hazards. Equipment that fails in connection with outages is repaired/replaced immediately unless the failed equipment can be removed from service and customers restored. In the latter case, the failed equipment is then scheduled for repairs/replacement.

- b. Inspection Response maintenance/repair

Inspections are part of PG&E's routine maintenance program. Deficiencies identified during inspections are prioritized based on condition and system impact, then scheduled for repair/replacement.

Discuss proactive replacement programs versus run-to-failure models for each group, including:

- 1. Whether there are specific line elements or equipment that are prioritized for preventive maintenance or replacement,
- 2. How those programs are established,
- 3. What data or information is utilized to make those determinations, and

4. What level of subjectivity is implemented in making those determinations

PG&E has developed asset management plans for its electric assets including distribution, substation and transmission. The asset management plan is based on collecting asset condition data, analyzing the data and determining the prioritization for replacement. Some assets are very complex, such as substation transformers, while other assets are very basic, such as a wood crossarm. The level of condition monitoring varies with the complexity of the asset. For example, substation transformers conditions are monitored using test like dissolved gas analysis (DGA) and partial discharge (PD) while wood crossarms are identified for replacement through our routine patrol and inspection programs (see "PG&E's GO 165 Program" Section in the Electric Distribution Preventive Maintenance (EDPM) Manual) for more information on patrol and inspection programs). Once a condition triggering replacement is identified, an EC tag is created with the replacement timeline (priority level) set in accordance with the TD-2305M-JA13 Job Aid: Create, Complete, Cancel for EC Notifications – Field Employees.

While there are instances when assets fail prior to replacement, PG&E does not use a run-to-failure approach to asset replacement. Through our routine patrol and inspection programs, we leverage a run-to-condition approach for basic assets that do not lend themselves to complex monitoring (i.e. gradual deterioration of a wood crossarm). Asset conditions that trigger replacement are well defined and have associated replacement timelines for the purpose of proactively replacing the asset prior to failure.

For more information concerning PG&E's asset management strategies, including inspections and proactive replacements, see Section 5.3.4.

See Attachment 1, Table 23 for the details and data associated with the initiatives discussed in this section.

Description of Programs to Reduce Ignition Probability and Wildfire Consequence

For each of the below initiatives, provide a detailed description and approximate timeline of each, whether already implemented or planned, to minimize the risk of its equipment or facilities causing wildfires. Include a description of the utility's initiatives, the utility's rationale behind each of the elements of the initiatives, the utility's prioritization approach/methodology to determine spending and deployment of human and other resources, how the utility will conduct audits or other quality checks on each initiative, how the utility plans to demonstrate over time whether each component of the initiatives is effective and, if not, how the utility plans to evolve each component to ensure effective spend of ratepayer funds.

Include descriptions across each of the following initiatives. Input the following initiative names into a spreadsheet formatted according to the template below and input information for each cell in the row.

- 1. Capacitor maintenance and replacement program
- 2. Circuit breaker maintenance and installation to de-energize lines upon detecting a fault

- 3. Covered conductor installation
- 4. Covered conductor maintenance
- 5. Crossarm maintenance, repair, and replacement
- 6. Distribution pole replacement and reinforcement, including with composite poles
- 7. Expulsion fuse replacement
- 8. Grid topology improvements to mitigate or reduce PSPS events
- 9. Installation of system automation equipment
- 10. Maintenance, repair, and replacement of connectors, including hotline clamps
- 11. Mitigation of impact on customers and other residents affected during PSPS event
- 12. Other corrective action
- 13. Pole loading infrastructure hardening and replacement program based on pole loading assessment program
- 14. Transformers maintenance and replacement
- 15. Transmission tower maintenance and replacement
- 16. Undergrounding of electric lines and/or equipment
- 17. Updates to grid topology to minimize risk of ignition in HFTDs
- 18. Other / not listed [only if an initiative cannot feasibly be classified within those listed above]

5.3.3.1 Capacitor Maintenance and Replacement Program

PG&E's capacitor maintenance, inspections and replacements are governed by Utility Procedure: TD-2302P-05. This utility procedure classifies maintenance tasks for miscellaneous electric overhead and underground equipment, including capacitor banks, fault indicators, interrupters, reclosers, voltage regulators, SCADA and Primary Distribution Alarm and Control (PDAC) controls, sectionalizers, streetlights, and sump pumps.

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

The testing entails recording a clamp-on ammeter reading on the primary jumper on each phase of the bank while the capacitor bank is energized. These values are compared to standard expected ranges based on the tank size and circuit voltage. If recorded values exceed the normal ranges, further inspection is required to determine the possibility of a failed capacitor unit or a bad connection.

The testing usually starts in the first quarter and is completed by April 1. All repairs or replacements are required by June 1. PG&E annually tests and inspects approximately 11,400 capacitors, approximately 10% of which require corrective action.

PG&E's Asset Management group has started a pilot program to review all outages as a result of fires due to Capacitor bank failures. Planning and Operations Distribution Engineering evaluates the Capacitor bank needs on that circuit for normal and emergency situations before a call is made to overhaul that capacitor bank in the same location or perhaps remove it if it is not necessary.

Costs for capacitor maintenance and replacement are not tracked separately but are included in PG&E's routine overhead maintenance program. As such, costs in the table show PG&E's non-enhanced maintenance in Tier 2 and Tier 3 HFTS areas for all overhead equipment.

Progress Timeline

- 1. **Before the upcoming wildfire season:** As noted above, capacitor banks in the distribution system, both overhead and pad-mounted, are tested and inspected annually, with any repairs completed by June 1.
- 2. **Before the next annual update:** See above for discussion of pilot program, which may affect PG&E's plans before the next annual update and future years.
- 3. **Within the next 3 years:** See above.
- 4. **Within the next 10 years:** See above.

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

The maintenance of circuit breakers and reclosers used as substation circuit breakers is governed by PG&E Utility Procedure TD-3322M SM&C Manual Circuit Breakers Booklet. This procedure classifies maintenance tasks for circuit breakers from visual inspections to more involved mechanism, compressor, and hydraulic system services, as well as complete overhauls. There are varying maintenance frequencies which are maintenance type dependent. In addition to the *time-based* approach, maintenance may also be *condition-based*. An example of a time-based maintenance task is a monthly visual inspection, while on the other hand an example of a condition-based task is maintenance based on breaker oil condition.

Voltage classification within PG&E are as follows: Transmission class – operate at a system nominal voltage of 60kV or higher; Distribution class – operate at a system nominal voltage of 4kV to below 60kV. Circuit breaker interrupting mediums include air, oil, vacuum, and sulfur hexafluoride (SF6).

Reclosers are traditional Distribution equipment but used as circuit breakers in substations for limited applications. Reclosers are used in substations as a more cost-effective application in cases where non-critical customers are served and space constraint exists. They are installed at Substation Distribution nominal voltage class level. The design and electrical characteristic of reclosers are limited to low load current, low interrupting capacity, and low switching compare to vacuum circuit breakers.

Circuit breakers are installed or replaced inside substations based on their age and condition, and for reliability and capacity needs. Circuit breakers used for line protection, referred to as feeder or line breakers, are designed to operate and de-energize distribution or transmission lines upon detecting faults.

Progress Timeline

1. *Before the upcoming wildfire season:* PG&E will continue to maintain circuit breakers consistent with the procedures described above.
2. *Before the next annual update:* See above.
3. *Within the next 3 years:* See above.
4. *Within the next 10 years:* See above.

5.3.3.3 Covered Conductor Installation

PG&E does not have a stand-alone targeted program to replace bare conductor with covered conductor. Instead, PG&E will install covered conductor and replace existing poles, cross-arms, and other equipment as part of PG&E's System Hardening Program. PG&E System Hardening Program is discussed in Section 5.3.3.17 below. Furthermore, all new construction of more than 4 spans will require covered conductor and compliance with TD-9001B-009, excluding maintenance and emergency.

Progress Timeline

- 1. Before the upcoming wildfire season: See Section 5.3.3.17.
- 2. Before the next annual update: See Section 5.3.3.17.
- 3. Within the next 3 years: See Section 5.3.3.17.
- 4. Within the next 10 years: See Section 5.3.3.17.

5.3.3.4 Covered Conductor Maintenance

PG&E does not contemplate creating a dedicated program for covered conductor maintenance. Instead, covered conductor will be maintained as part of routine overhead maintenance conducted through the GO 165 Program, which is focused on the identification, assessment, prioritization, and documentation of compelling abnormal conditions, regulatory conditions, and third party caused infractions that negatively impact safety or reliability. These conditions are identified during patrols and inspections of PG&E's distribution facilities, and may occur as a result of operational use, degradation, deterioration, environmental changes or third-party actions.

Costs for PG&E's non-enhanced overhead maintenance are shown in Section 5.3.3.1.

Progress Timeline

- 1. **Before the upcoming wildfire season:** PG&E will include any areas where covered conductor has been installed in its regularly scheduled GO 165 program of patrols and inspections and will seek to timely address any maintenance conditions that are identified.
- 2. **Before the next annual update:** See above.
- 3. **Within the next 3 years:** See above.
- 4. **Within the next 10 years:** See above.

5.3.3.5 Crossarm Maintenance, Repair, and Replacement

PG&E has an extensive condition monitoring program for overhead assets, including crossarms, in accordance with requirements in GO 165. PG&E conducts annual patrols in urban areas and bi-annual patrols in rural areas, visually looking for damaged equipment and other defects on the distribution overhead system. A detailed inspection is performed every 5 years, looking for any damaged or deteriorated equipment. Through these inspection programs, PG&E identifies approximately 4,700 crossarms for maintenance, including replacement and repairs, every year. Some crossarms are being replaced, in conjunction with pole and conductor replacement, as part of PG&E's System Hardening Program, discussed in Section 5.3.3.17 below.

The crossarm maintenance program is considered a fully implemented program, as crossarms have been replaced and repaired for many years and funding is part of the GRC. Crossarms identified for maintenance each year by various inspection programs are scheduled for replacement in the following 3 to 24 months, depending on condition and location. Crossarms within the Tier 2 and 3 HFTD areas are completed within 12 and 6 months of identification, respectively.

PG&E inspectors and construction supervisors conduct post-job reviews for crossarm maintenance work performed by contract and internal crews to ensure the work matches the work call for in the job order and is in compliance with GO 95 requirements. No additional metrics are tracked related to crossarm maintenance.

The crossarm maintenance program is continuing to evolve and improve annually. The current focus is to meet Tier 2 and 3 HFTD area deadlines, reducing overall system risk.

For PG&E's transmission lines, crossarm maintenance is generally performed as part of the overhead inspection program with repairs and/or replacement done as determined necessary during these inspections. Further details can be found in the maintenance and inspection Section 5.3.4. It is a fully implemented program, as crossarms have been reinforced or replaced for many years and funding is part of the Transmission Owners Tariff Rate Case. Crossarms identified for replacement or repair each year by the inspection programs are scheduled for replacement or repair in the following 3 to 24 months, depending on condition and location. Crossarms within the Tier 2 and 3 HFTD areas are completed within 12 and 6 months of identification, respectively. Crossarms may be reinforced immediately if warranted by condition and location.

Progress Timeline

- 1. **Before the upcoming wildfire season:** PG&E will continue to repair/replace crossarms pursuant to its existing condition-based maintenance program as described above.
- 2. **Before the next annual update:** See above.
- 3. **Within the next 3 years:** See above.
- 4. **Within the next 10 years:** See above.

5.3.3.6 Distribution Pole Replacement and Reinforcement, Including with Composite Poles

PG&E has an extensive condition monitoring program for wood poles in accordance with requirements of GO 165. PG&E conducts annual patrols in urban areas and bi-annual patrols in rural areas, visually looking for damaged poles and other defects on the distribution overhead system. PG&E performs a detailed inspection every 5 years to look for external damage or deterioration, as well as an intrusive inspection approximately every 10 years to identify internal or below ground decay that may be present in the pole. Through these inspection programs PG&E identifies approximately 10,000 wood poles for replacement and 4,000 wood poles for reinforcement every year. Poles identified for reinforcement are in good condition, except for decay around the ground line. By installing a steel truss and banding it to these poles PG&E can restore the strength of the pole to 100%. In addition, the pole replacement program replaces poles that need to be upgraded to support the attachment of telecommunications or cable companies' facilities. Finally, the pole replacement program replaces poles that PG&E has determined are overloaded.

Both pole remediation programs (replacement and reinforcement) are considered fully implemented, as poles have been remediated for many years and funding is part of the GRC. Poles identified for remediation each year by the various inspection programs are scheduled for replacement in the following 3 to 24 months, depending on condition and location. Poles within the Tier 2 and 3 HFTD areas are completed within 12 and 6 months of identification, respectively.¹⁰

PG&E inspectors and construction supervisors conduct post-job reviews for pole replacement work performed by contract and internal crews to ensure the work matches the work called for in the job order and is in compliance with GO 95 requirements. In addition, the pole replacement program was monitored by tracking the on-time completion of pole replacements. This metric was reported weekly to Distribution Operations leadership. The on-time performance metric target is 95 percent. The 2016, 2017 and 2018 performance levels were 93, 93 and 94 percent. In 2019, PG&E transitioned to a risk-based prioritization model and discontinued tracking the on-time performance metric.

The pole reinforcement program is part of the Pole Test & Treat (PT&T) program. As such, quality control for pole reinforcement is conducted by a team of PT&T inspectors. Each week a sample of poles selected from pole reinforcement projects completed the previous week is audited for compliance with the reinforcement specification. Projects that do not meet a 95 percent compliance threshold are rejected and must be re-reinforced and re-audited. The 2016, 2017 and 2018 quality levels were 94, 95 and 97 percent.

¹⁰ PG&E also replaces some failed poles on an emergency basis as part of its Routine Emergency and/or Major Emergency Programs. In addition, PG&E will be replacing existing poles as part of its System Hardening program, discussed in Section 5.3.3.17 below, where such replacement is necessary to satisfy the requirements of that program.

Both pole remediation programs are continuing to evolve and improve annually, with the ultimate goal to meet 100% quality. The current focus is to meet Tier 2 and 3 HFTD area deadlines, reducing overall system risk.

PG&E believes that it may be appropriate to use non-wood (e.g., steel or composite) poles as replacement poles in at least some HFTD locations. PG&E has been evaluating both wood and non-wood poles to determine which options are the most reasonable and effective. In 2019, PG&E, along with San Diego Gas and Electric Company (SDG&E) and Southern California Edison Company (SCE), tested 11 different sets of poles (33 total) from 7 different manufacturers for fire resiliency via burn tests and fire prevention via simulated tree strikes. The poles tested include steel, ductile iron, concrete, composites with and without fire resistant coatings or coverings, and wood with fire resistant coverings. Results from the tree strike simulations yielded very similar system response for all poles tested and were comparable to typical wood poles. The burn tests similarly had relatively good results for most of the poles considered. PG&E will continue to evaluate these options, as well as considering other factors such as cost, availability, and longevity as it decides whether (and in what circumstances) it is appropriate to use composite poles as replacement poles.

Progress Timeline

- 1. **Before the upcoming wildfire season:** PG&E will continue to replace/reinforce poles pursuant to its existing condition-based maintenance program as described above. PG&E will continue to evaluate the reasonableness of using composite poles as replacement poles.
- 2. **Before the next annual update:** PG&E will continue to replace/reinforce poles pursuant to its existing condition-based maintenance program as described above. PG&E may adjust or refine its program based on new information or technology.
- 3. **Within the next 3 years:** See above.
- 4. **Within the next 10 years:** See above.

5.3.3.7 Expulsion Fuse Replacement

PG&E proposes to eliminate non-exempt overhead line equipment in HFTD areas over time. Non-exempt equipment is equipment that may generate electrical arcs, sparks, or hot material during its normal operation. Due to these characteristics, PRC Section 4292 requires all utilities to maintain at least a 10-foot clearance of vegetation from the outer circumference of any pole that has non-exempt equipment. However, CAL FIRE tests and certifies some equipment as exempt from the vegetation clearance requirements of PRC Section 4292 where it is determined to be safer to use.

To address increasing wildfire risks caused by changing climate conditions, PG&E created a program to replace non-exempt fuses and cutouts to further reduce fire risk. The replacement of non-exempt equipment with exempt equipment will further reduce fire risk since the exempt equipment is considered “non-expulsion” and does not generate arcs/sparks during normal operation.

Starting in 2019, PG&E forecasts replacing approximately 625 fuses/cutouts, and other non-exempt equipment identified on the pole each year for seven years in Tier 2 and Tier 3 HFTD areas. In addition to non-exempt fuse replacement, PG&E has created a program to replace non-exempt surge arresters, which is discussed in Section 5.3.3.17.

Progress Timeline

- 1. *Before the upcoming wildfire season:* PG&E will continue implementing the non-exempt fuse replacement program described above at a forecast rate of 625 fuses/cutouts per year.
- 2. *Before the next annual update:* PG&E will continue implementing the program described above. PG&E may make adjustments to the program based on lessons learned in 2020.
- 3. *Within the next 3 years:* See above.
- 4. *Within the next 10 years:* See above.

5.3.3.8 Grid Topology Improvements to Mitigate or Reduce PSPS Events

PG&E has planned a number of initiatives to reduce and mitigate the impacts of PSPS events in 2020 and beyond. The select initiatives related to grid topology improvements are described below.

Transmission Line Assessments

PG&E’s PSPS Program has established criteria for when overhead electric transmission line facilities can be excluded from being de-energized in PSPS events. These criteria include assessing the following for transmission line facilities within high-risk areas projected to experience PSPS weather conditions: (1) health of all assets on the transmission line facility; (2) historical operating performance; (3) vegetation risks; and (4) fire spread potential. By applying these criteria, PG&E will be able to consider whether to exclude certain transmission lines from de-energization during a PSPS event, when safe to do so which would reduce the risk of service interruptions to customers served by those transmission lines during PSPS events.

Prior to next fire season, PG&E will be evaluating all 552 transmission lines in HFTD areas to determine which lines can be removed from future PSPS Event scope via: supplemental inspections (ultrasonic), below-grade inspections and repairs, increased Vegetation Management (i.e. expanded Rights-Of-Way), accelerated repairs or replacement of assets.

Transmission Line Sectionalizing

PG&E has been installing SCADA switches on transmission lines to support faster restoration during outage events for the last few years. PG&E’s plan is to enhance transmission segmentation strategies including additional SCADA-controlled switching. PG&E has identified various transmission lines where additional switching devices will be utilized to further sectionalize transmission lines to be able to minimize the number of customers being impacted by PSPS outages. In 2019, the program added 54 new SCADA transmission switches and another 23 are planned for 2020 to provide switching flexibility as well and sectionalizing for PSPS events

Distribution Segmentation and System Hardening

PG&E’s plan is to enhance its distribution segmentation strategies including: (a) adding automated sectionalizing devices (targeting 592 such devices in 2020); (b) circuit reconfiguration / pre-PSPS Event switching; and (c) additional system hardening to support PSPS switching. PG&E has identified various distribution lines where additional switching devices coupled with targeted system hardening may be utilized to further sectionalize distribution feeders to be able to minimize the number of customers being impacted by PSPS outages.

Microgrids for PSPS Mitigation

PG&E is proposing to pursue resiliency and reliability improvements to mitigate the customer impacts of PSPS through permanent and temporary front-of-the-meter

microgrid solutions, also referred to as Resilience Zones.¹¹ Microgrids can reduce the number of customers de-energized during PSPS events, as well as provide additional impact mitigation by energizing shared community resources that support the surrounding population.

2019 Implementation: In its 2019 WMP, PG&E described its plan to operationalize one pilot mid-feeder microgrid using a pre-installed interconnection hub and temporary generation. Implementation concluded successfully when the pilot site (Angwin Resilience Zone in Napa County) reached operational readiness in September 2019. PG&E successfully utilized temporary generation at its pilot mid-feeder microgrid site as well as in three additional safe-to-energize substations in Calistoga, Grass Valley, and Placerville to safely re-energize thousands of customers during the October and November PSPS events.

Approximate Timeline for 2020 and Beyond: Building on the critical PSPS impact mitigation role that front-of-the-meter microgrids played in 2019, PG&E's goal is proposing, subject to Commission approval and receipt of additional regulatory approvals, to operationalize additional microgrids for PSPS mitigation before the next annual update. PG&E is expanding its projects to include substation-sited and mid-feeder microgrids, using a combination of mobile and permanent generation depending on the most feasible technology application. While PG&E is pursuing an aggressive acceleration of microgrid deployments in 2020, its timeline is contingent on several factors including land availability and permitting, construction resources, input from the Commission and community representatives, and bids received as part of the DGEMS Request for Offers. The microgrid deployment timeline for 2021 and future years will be informed by PG&E's near-term projects.

Site selection: These microgrids will vary in location, size, and design. In determining where to site microgrids for PSPS impact mitigation in 2020, PG&E is using a multifaceted approach that seeks to support the greatest number of customers via substation energization where possible, while supporting community resilience through the energization of shared resources in areas where large-scale substation deployments are not feasible in the near term. As a starting point in site selection, PG&E assesses the expected relative frequency of future PSPS impacts through analysis of historical meteorological data, prior PSPS event impacts, and parallel work-in-progress directed at reducing future impacts. Additionally, PG&E seeks to complement its internal location screening process for microgrids with county and local government collaboration to ensure that local priorities help shape site selection and design where technically feasible.

¹¹ The targeted units and spend associated with Microgrids for PSPS mitigation in this 2020 WMP are provided for informational purposes only. Microgrids in this category may include temporary mid-feeder microgrids, temporary microgrids located at substations, temporary single-customer microgrids to power critical facilities needed to ensure societal continuity, and permanent distributed generation-enabled microgrid services (DGEMS) at substations. The actual units operationalized and spend incurred may change.

While in certain areas PG&E may be able to operationalize microgrids for PSPS mitigation without grid topology modifications, at most sites this initiative will require some of the following changes to grid infrastructure:

Substation Make-Ready Infrastructure: In January 2020, PG&E submitted testimony in the Microgrid and Resiliency Strategies Rulemaking (R 19-09-009) seeking approval of cost recovery to engineer and construct additional infrastructure at substations in order to make them ready for the integration of permanent or temporary distributed generation resources (the Make-Ready Program). This would enable PG&E to locate distributed generation resources at prioritized PG&E substations with the goal of providing continuous service to the greatest number of customers where it is projected to be safe to do so during PSPS events. While no two substations are configured the same, PG&E anticipates that the following will be required at each substation to allow the substation to operate in islanded mode when power from the broader grid is shut off: ground grids, circuit breakers or line reclosers with sync scope capabilities, fuse disconnect switchgear, additional substation bus infrastructure, and additional construction work.

Pre-Installed Interconnection Hubs: Building on its 2019 pilot project,¹² PG&E expects to expand its deployment of pre-installed interconnection hubs that energize mid-feeder microgrids by allowing for safe, rapid connection of temporary generation outside of substations. As with the 2019 pilot Resilience Zone in Angwin, mid-feeder microgrids are designed to energize islanded areas within towns impacted by PSPS events, thereby enabling some community resources to continue serving the surrounding population. Generally, pre-installed interconnection hubs (PIHs) will consist of pad-mounted transformer(s) and associated interconnection equipment, ground grid, grid isolation and protection devices (reclosers and switches), and security fencing.

Isolation Devices: These devices allow PG&E to safely isolate the section to be energized from the larger grid during a Public Safety Power Shutoff event. In some instances, PG&E may need to install new devices or replace existing devices.

Establishing PSPS Thresholds for Hardened Distribution Facilities

In 2019, PG&E completed over 2,500 miles of enhanced vegetation management trimming along power lines and hardened over 170 miles of electric distribution facilities within HFTDs. As a result of this effort, as well as other wildfire risk reduction efforts that PG&E undertook, ignitions attributed to PG&E's equipment in HFTDs decreased by 24% in 2019, when compared to the average of the three prior years (2016-2018).

One of the other initiatives that contributed to reduced ignitions attributed to PG&E's equipment was the execution of its PSPS Program, where PG&E proactively de-energized high-risk electric power lines to eliminate the likelihood of PG&E's electric power lines creating an ignition that could result in a catastrophic wildfire. Although PG&E's execution of its PSPS program accomplished its objectives of preventing ignition of any deadly wildfires while minimizing public safety impact, PG&E recognizes there are many opportunities to improve not only the execution of its PSPS program, but

¹² See Section 4.6.2.2 in PG&E's 2019 WMP.

to also reduce the required scope of future events and the associated customer impact (as well as to reduce overall wildfire risk from PG&E assets) through execution of its distribution asset hardening program.

Refining Criteria for Hardened Distribution Facilities During Potential PSPS Events

PG&E’s PSPS Program has established criteria for when overhead electric transmission line facilities can be excluded from being de-energized in PSPS events. PG&E is working to develop similar operating criteria for when overhead *distribution* line facilities located within HFTDs can remain in-service during PSPS weather conditions. Although PG&E has completed over 170 miles of system hardening of its distribution facilities, due to the limited performance history of hardened overhead distribution facilities during PSPS weather conditions, PG&E will be performing additional analysis to determine under what conditions these lines can safely remain energized.

Approach to Performance Data for Overhead Hardened Distribution Facilities

PG&E will obtain performance data for portions of its overhead system that have been hardened through two initiatives: (1) Simulating the performance of all fire hardened overhead distribution facilities using existing failure mode data and Finite Elements Analysis (FEA); and (2) Monitoring, collection, and assessment of field performance of hardened distribution facilities.

1. Evaluate Wind and Vegetation Strike Resilience Performance via Finite Element Analysis: PG&E plans to perform Finite Element Analysis (FEA) to simulate the operating performance of overhead distribution facilities that have been hardened against various wind and vegetation strikes that these facilities could experience during extreme fire-weather events. This analysis will model the hardened distribution facilities and the current inventory of vegetation around those facilities, collected via LIDAR from the 2019 WSIP. FEA simulations will determine which trees in the vicinity of electric facilities could lead to a failure of the hardened facilities under extreme weather conditions. Specifically, this analysis will determine for each hardened facility, the location and size of tree and/or tree branches, angle of trajectory launch of tree and/or tree branches, and the magnitude of the impact of overstrikes along with the magnitude and direction of wind gusts that that could create damage on the hardened facilities where an ignition is likely.
2. Determine Safety Factor Requirements and Correlate to Historical Climatology. Analysis: PG&E plans to utilize historic outage and ignition data and the most up-to-date FEA to calculate performance improvements for the distribution facilities that have been hardened and/or undergone enhanced vegetation management. The results of the system hardening improvements and FEA would be used to determine safety factors for locations where there are hardened distribution facilities. The safety factors developed would consider projected local weather conditions and vegetation risks around the hardened overhead facilities. Once safety factors are computed for the hardened distribution facilities, PG&E plans to review its OPW meteorology model for predicting future outages under various extreme wind conditions for opportunities to adjust the OPW model to reflect the additional safety factors gained for hardened distribution facilities. Since PG&E’s OPW model relies

on historical PG&E operating performance information, it does not yet have enough historical data on the operating performance on hardened distribution facilities to factor in the increased strength and resiliency of those facilities. However, PG&E should be able to use historic and/or simulated performance information from the FEA to establish simulated safety factors for hardened facilities, which could then be used to draft criteria and local condition thresholds, which if not met could exclude certain hardened distribution facilities from being de-energized in PSPS events, subject to projected extreme weather conditions. In addition, PG&E will identify additional safety factors for hardened facilities, determine residual local ignition risk, and develop risk-informed local corrective action plans that could include additional inspections near time of weather events, to address specific outstanding risk drivers based on local and regional operating conditions.

3. Monitor and Collect Performance Information for Deployed Hardening Distribution Facilities: From the 2019 PSPS events, PG&E has collected and analyzed field information around the hazards and/or damage to its hardened distribution facilities to build its knowledge around the performance of hardened facilities. Over the next several years, PG&E plans to monitor and collect information on the operating performance of its hardened distribution facilities to be able to substantiate the results obtained through its FEA of its hardened facilities. As field data and industry information is obtained that validate or directionally validate the FEA results of hardened facilities, PG&E will be able to adjust its PSPS criteria for its hardened distribution facilities on a location by location basis.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E will evaluate all its transmission lines located in HFTD areas to determine whether they meet PG&E's criteria for excluding them from the scope of de-energization during PSPS events. PG&E plans to install 23 additional SCADA switches on transmission lines in 2020 to provide switching flexibility as well as sectionalizing for PSPS events.
2. **Before the next annual update:** See above. In addition, PG&E plans to continue operationalizing microgrid installations; the precise scope and schedule for these installations will be based evaluation of the current program and best available information.
3. **Within the next 3 years:** See above.
4. **Within the next 10 years:** See above.

5.3.3.9 Installation of System Automation Equipment

PG&E has had a robust automation program for many years. Currently, 97% of distribution substations are equipped with SCADA and nearly 10,000 automated devices (switches and reclosers) have been installed throughout the distribution system. In 2018 and 2019, the focus was adding SCADA functionality to all reclosers and distribution breakers (excluding 4 kV breakers) within the Tier 2 and 3 HFTD areas. The effort to add SCADA capability to all line reclosers (737 devices) was completed in June 2019. In addition, SCADA capability was added to 17 circuit breakers in 2019, leaving just 11 breakers within the fire areas (excluding 4kV) to complete in 2020.

In addition, in the near term, the distribution line automation program will target life cycle control replacements of legacy 4C controllers (250 reclosers) to ensure reliable operation of reclosers.

Also, in an effort to further sectionalize distribution circuits and limit the duration as well as the number of customers impacted by PSPS events, PG&E is proposing to install additional line reclosers at Tier 2 and Tier 3 HFTD boundaries. In addition to the automation programs, PG&E is also evaluating different protection schemes and equipment that may further reduce the likelihood of a fire ignition when a system failure occurs. The program includes:

- **Fusesavers™:** Fusesavers™ enable localized isolation of all phases of a line when a problem is detected on only one or two phases. For example, if a single wire down on a three-phase line is detected, Fusesavers™ can automatically and locally de-energize all three phases. Installing these devices can also create additional points where lines can be segmented to support other wildfire risk reduction programs such as PSPS.
- **High Impedance Fault Detection:** PG&E is piloting and proposes to deploy newer protection capabilities of reclosers and circuit breakers that increase the ability to detect high impedance faults.
- **Increased Protection Sensitivity:** PG&E is evaluating the use of more sensitive protection settings and use of fast curves set on reclosers and circuit breakers. The proposed settings and use of fast curves would reduce the amount of energy experienced when a system failure occurs. This may lower the potential for a fire ignition to occur. The proposed protection schemes, however, could reduce the ability to coordinate with protective devices downstream and will lead to an increase in the size and duration of outages.

Progress Timeline

- 1. **Before the upcoming wildfire season:** PG&E will pursue the system automation initiatives described above including adding SCADA capability to circuit breakers, installation of transmission SCADA switches, replacement of legacy 4C controllers and installation of additional sectionalization devices. PG&E is also evaluating new proposed protection schemes that it will deploy in the future when and if appropriate.
- 2. **Before the next annual update:** See above.
- 3. **Within the next 3 years:** See above.
- 4. **Within the next 10 years:** See above. PG&E will continue to monitor SCADA device and system performance. PG&E will create replacement plans when device or system failure rates exceed acceptable levels.

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

There are no specific programs associated with connector replacement in distribution. All replacements are incorporated into Distribution System Hardening (discussed in Section 5.3.3.17) and distribution maintenance. For PG&E's transmission lines, maintenance of connectors is generally performed as part of the overhead inspection program with repairs and/or replacement done as determined necessary during these inspections. Further details can be found in Section 5.3.4.

Progress Timeline

- 1. **Before the upcoming wildfire season:** PG&E will continue to maintain, repair and/or replace connectors pursuant to its established condition-based maintenance programs. PG&E will also replace existing connectors with new equipment on facilities that are hardened as part of the System Hardening Program.
- 2. **Before the next annual update:** See above.
- 3. **Within the next 3 years:** See above.
- 4. **Within the next 10 years:** See above.

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

PG&E will work to improve access to electricity for customers and other residents during PSPS events. PG&E plans to install and operate local generation equipment at the community or household level, including by building out of microgrid's to reduce the number of customers impacted in safe-to-energize areas as well. PG&E also may deploy backup generation to individual facilities in exceptional circumstances.¹³ PG&E's microgrid plans are discussed in Section 5.3.3.8. PG&E's backup generation plans are discussed in Section 5.6.2.

Progress Timeline

- 1. Before the upcoming wildfire season: See discussion of microgrid/resilience zone plans in Section 5.3.3.8 and discussion of backup generation plans in Section 5.6.2.
- 2. Before the next annual update: See above.
- 3. Within the next 3 years: See above.
- 4. Within the next 10 years: See above.

¹³ PG&E notes that backup generation does not require modification to grid design or system hardening, which is the topic of Section 5.3.3, but it does provide access to electricity at the individual customer level.

5.3.3.12 Other Corrective Action

Substation Animal Abatement: PG&E has been conducting an animal abatement program for its substations, with reliability (i.e., lower customer outage) as the main driver. The program was expanded in 2018 to address wildfire risks. Animal abatement was identified during the 2019 WSIP as a necessary mitigation to minimize fire ignition, specifically in Tier 2 and Tier 3 HFTD areas. The animal abatement program mitigates the risks to safety and reliability at substations prone to outages resulting from animal contacts. Animal contacts at sites that do not meet guidelines for defensible space may result in fire ignition; however, the risk of wildfire is low considering the history of substation animal contacts not resulting in wildfire and the progress of the existing capital animal abatement program. Animal contacts are more likely to be a contributing cause which can exacerbate the deterioration of existing equipment, which may result in a catastrophic failure that can project ignited materials into HFTD areas. Substations within HFTD areas requiring animal abatement were evaluated utilizing the defensible space criteria and WSIP. Thus far, 59 locations have been identified as requiring animal abatement; 18 were completed in 2019 and the remaining are being prioritized for completion.

Transmission Line Programs/Initiatives: PG&E has many corrective actions to enhance and ensure the strength of the transmission system. A few major initiatives are:

- Steel structures with the possibility of lead-based paint have been inspected to determine the actual coating type. A program has been begun in order to coat those structures identified with the lead-based paint to be recoated using non lead-based paint. This program prolongs the life expectancy and overall health of the steel structures. Over the next several years, the towers identified will be recoated in order to reduce environmental and safety risks, especially near schools, homes and agricultural areas.
- The replacement, reinforcement and PT&T program described in Section 5.3.3.6 also applies to Transmission wood poles, based on inspections further discussed in Section 5.3.4. As with the distribution program, it is a fully implemented program, as poles have been replaced and/or reinforced for many years and funding is part of the Transmission Owners Tariff Rate Case, transmission poles identified for replacement or reinforcement each year by the various inspection programs are scheduled for reinforcement in the following 3 to 24 months, depending on condition and location. Transmission poles within the Tier 2 and 3 HFTD areas are completed within 12 and 6 months of identification, respectively. Poles may be replaced or reinforced immediately if warranted by condition and location.
- Insulators in highly contaminated areas have been observed as more troublesome than their counterparts in non-contaminated areas. Insulators that are determined to have these contamination issues have been targeted in the insulator washing program, which creates subsets of insulators to be periodically washed to prolong their life expectancy and overall health.
- Existing idle transmission facilities within HFTD areas can be de-energized to mitigate risk of wildfire. Additionally, safety concerns are addressed through the inspection and maintenance process. Idle facilities are also prioritized based on risk

for either removal or future utilization, depending on system requirements for each location.

- Nearly all birds and their nests are protected by the Federal Migratory Bird Treaty Act of 1918 and California Fish and Game Code. PG&E's standards establish the requirements and responsibilities for an Avian Protection Plan that reduces the risk to migratory and threatened and endangered birds and enhances the Company's customer service and regulatory compliance.
- The NERC Alert program is necessary to comply with the October 7, 2010 NERC Recommendation to Industry for "Consideration of Actual Field Conditions in Determination of Facility Ratings." The NERC recommendation directs utilities first to determine if their Facility Ratings Methodology will produce appropriate ratings, even when considering differences between design and actual field conditions. Second, the NERC recommendation directs utilities to review their transmission facility ratings to confirm that any differences observed between design and actual field conditions are within the design tolerances as defined by the utilities Facility Ratings Methodology. Third, recipients of this recommendation were directed to submit a plan to NERC describing how an assessment of its facilities will verify that actual field conditions conform to the design tolerances in accordance with its Facility Ratings Methodology.
- Transmission System Capacity focuses on increasing the electric transmission system capacity either via system expansion or changes in system configuration and operation. The strategy for the Transmission Line Capacity and Transmission Substation Capacity programs are similar and often work in tandem. The goal of both programs is to maintain continuity of service to its customer in a cost-effective manner. Transmission system capacity needs are identified through annual transmission system assessment studies, which investigate projected transmission performance based upon forecasted load demand and resource changes over a 10-year planning horizon against applicable NERC, WECC, and CAISO reliability standards and criteria for transmission planning.

Wildfire Safety Inspection Program Distribution Repair Work: As discussed in Section 5.3.4, in 2019, PG&E began a Wildfire Safety Inspection Program or "WSIP" to expedite and expand the routine detailed inspections performed in Tier 2 and Tier 3 HFTD areas. PG&E has completed its extensive inspections of overhead electric distribution facilities and substations in High Fire-Threat District (HFTD) areas as part of the WSIP Program. As a result of these enhanced and accelerated inspections, PG&E identified a substantial amount of repair and replacement work to be completed. In 2019, PG&E completed high priority corrective actions created from deficiencies identified resulting from these enhanced inspections, and will complete the lower priority tags over the next three years. Completion of lower priority tags are prioritized based on location and potential wildfire risk. This wildfire risk is based upon a failure mode and effects analysis, historical asset ignition analysis, wildfire spread and consequence, and egress for each maintenance tag.

Progress Timeline

1. ***Before the upcoming wildfire season:*** PG&E will pursue the substation and transmission initiatives described above.
2. ***Before the next annual update:*** See above.
3. ***Within the next 3 years:*** See above.
4. ***Within the next 10 years:*** See above.

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

In 2015, PG&E started its pole loading initiative, which requires specific analysis of pole loading before setting a new pole, in response to multiple GO 95 revisions to address vertical loading due to existing assets on the poles as well as other attachments' impact on pole structure stability. To comply with the GO standards, PG&E implemented a "Tool Modernization" project which enhanced pole loading calculation quality by using Osmose "O-Calc Pro," O-Calc Pro, a software tool that can be used by personnel in the field, enables modeling the pole along with conductors, communication attachments, and guy wires. In addition, PG&E can now model percent wood strength of every pole in the loading calculation tool to provide accurate assessments based on available condition data. The percent wood strength used in the pole loading calculation is provided by PG&E's Pole Test and Treat team and must be from an inspection that has occurred in the last five years.

In 2016, PG&E performed pole loading assessments, which indicate an expected overload rate of less than 1% of PG&E's wood pole population. The poles at highest risk of being overloaded are jointly owned, Class 5 (smallest pole) with both primary and secondary conductors and multiple communication attachments.

In 2019, PG&E initiated a new pole loading assessment proof of concept, via performance of desktop reviews. PG&E is utilizing baseline pole loading calculation models, created using EDGIS data, a series of algorithms and conservative assumptions used to fill in the data gaps and is working with vendors to compare these baseline calculations to third-party imagery (e.g., google streetview/earth, field collected photographs) to either confirm or update the model. This proof of concept has been successful in the pilot population and is expanding to include analysis of poles where additional third-party imagery (e.g., LiDAR, field collected photograph, etc.) has recently been collected.

PG&E has strengthened pole loading model parameters and variables considering historical data with various meteorological factors (e.g., wind speed). Sizing for new and replacement distribution pole installations now considers historical peak wind speeds in areas where they exceed GO 95 defined wind speeds. In order to maximize the likelihood that poles are strong enough to withstand higher wind speeds, a pole loading calculation must be performed both at the loading conditions assumed by appropriate GO 95 conditions (load case) and at a summer peak wind load case (e.g., peak wind for location, 60-degree minimum temperature, no ice). Pole loading models are required to meet the safety factor requirements for both load cases.

PG&E has also increased the required setting depth of a pole in the updated Allowable Overtum Moment table by comparing the values to the ultimate potential ground-line moment for a given pole design. This more stringent requirement supersedes previous PG&E requirements for minimum setting depth and will result in a greater amount of available pole utilization at the equivalent soil overturn strength.

Since the pole loading infrastructure assessment proof of concept was performed in 2019 and the program is beginning in 2020, it is considered a new program. Initially, the program is focusing on assessment of poles in the Tier 2 and 3 HFTD areas, with

the goal to be fully implemented (100% poles analyzed) in these areas in 2024. Poles located in Tier 1 will follow, with the goal to be fully implemented (100% poles analyzed) by 2030. In addition to prioritizing by location, pole assessments are being prioritized using the baseline models and pole characteristics from EDGIS (e.g., small class, multiple circuits, treatment). Poles scheduled for potential replacement as part of the System Hardening program discussed in Section 5.3.3.17 will be assessed prior to replacement to determine whether or not the existing pole can bear the load associated with the covered conductor and other equipment that will be installed as part of the program.

PG&E’s estimating and engineering personnel perform quality checks on the desktop reviewed pole loading calculations performed by the contract crews. The assessment program is monitored by tracking the volume of pole loading calculations uploaded to PG&E’s database with a “desktop review” or better status (e.g., “field verification” or “issued for construction”).

The pole loading assessment program is designed to be a 10-year effort, where roughly 10% of the system is analyzed annually. As PG&E has approximately 2.3 million distribution poles, it is anticipated that roughly 230,000 poles are analyzed for desktop review annually. The ultimate goal is to have analyzed all distribution poles systemwide by 2030.

PG&E is also conducting a Wind Loading Assessment emerging technology project. This project will reduce risk by providing asset intelligence to identify locations that require corrective actions driven by pole safety factors or limitations for wind speeds. The project will leverage existing LIDAR data from Vegetation Management efforts to geo-correct pole locations. Objectives of this project include a greater understanding of failure modes, establishment of a common repository of data gathered, and effectively updating workflows of key asset systems to align with new data strategies. Wind loading segmentation will be performed to identify the wind loading of each asset on a support structure and integrate findings into appropriate systems.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E plans to perform pole loading assessments as described above at a rate of approximately 230,000 poles per year in HFTD Tier 2 and 3 locations through 2024. PG&E will also perform pole loading calculations on poles identified for potential replacement as part of the System Hardening program.
2. **Before the next annual update:** See above. PG&E will continue to evaluate the program and may make adjustments based on any new insights gained.
3. **Within the next 3 years:** See above.
4. **Within the next 10 years:** See above. Once PG&E has finished assessing poles in HFTD Tiers 2 and 3, it will begin to assess poles in the rest of the system. This transition is expected to take place in 2024, and PG&E currently expects to complete all assessments by 2030.

5.3.3.14 Transformers Maintenance and Replacement

Distribution Transformer maintenance will primarily be covered through PG&E's GO 165 program. The GO 165 Program is primarily focused on the identification, assessment, prioritization, and documentation of compelling abnormal conditions, regulatory conditions, and third party caused infractions that negatively impact safety or reliability. These conditions are identified during patrols and inspections of PG&E's distribution facilities, and may occur as a result of operational use, degradation, deterioration, environmental changes or third-party actions. Transformers may be maintained, repaired, or replaced based on their condition as assessed during the GO 165 process. Transformers that fail in connection with an outage may be replaced as part of PG&E's Routine Emergency or Major Emergency programs. PG&E is also replacing certain transformers on circuits that are included in the System Hardening program discussed in Section 5.3.3.17.

Progress Timeline

- 1. *Before the upcoming wildfire season:* PG&E will continue to maintain, repair, or replace transformers as warranted by their condition as part of its ongoing GO 165 maintenance program and Emergency programs. PG&E may also replace certain transformers as part of its Grid Hardening program discussed in Section 5.3.3.17.
- 2. *Before the next annual update:* See above.
- 3. *Within the next 3 years:* See above.
- 4. *Within the next 10 years:* See above.

5.3.3.15 Transmission Tower Maintenance and Replacement

As with other assets in PG&E’s transmission system, transmission structures¹⁴ undergo regular maintenance involving inspections and repairs along with replacements when required. See Section 5.3.4 for further information regarding inspection and repairs. The transmission structure maintenance program is a fully implemented program, as structures have been reinforced or replaced for many years and funding is part of the TO Rate Case. Structures identified for replacement or repair each year by the inspection programs are scheduled for replacement or repair in the following 3 to 24 months, depending on condition and location. Structures within the Tier 2 and 3 HFTD areas are completed within 12 and 6 months of identification, respectively. Structures may be reinforced immediately if warranted by condition and location.

For risk-informed asset replacement decisions beyond inspection findings, the following process is followed. Through various models and analysis discussed in part in Section 5.3.3.18, transmission circuits were risk-ranked, and then further reviewed structure-by-structure to determine and ensure their asset through comprehensive replacement projects when necessary. The primary goal being the reduction of risk on a circuit-based level. There are multiple data sources that feed into this process, including but not limited to asset condition, location, parameters, and age as well as reference information on assets life cycle. Using this process, PG&E has identified several circuits that will undergo capital projects in the coming years.

Progress Timeline

- 1. Before the upcoming wildfire season: PG&E will continue to maintain, repair, or replace transmission towers as warranted by their condition as part of its ongoing maintenance programs.
- 2. Before the next annual update: See above.
- 3. Within the next 3 years: See above.
- 4. Within the next 10 years: See above.

¹⁴ Please note that for the purpose of this section, a transmission tower refers to all transmission structures.

5.3.3.16 **Undergrounding of Electric Lines and/or Equipment**

PG&E plans to underground some portion of its distribution system to reduce risks associated with wildfires as part of its System Hardening program, discussed in Section 5.3.3.17 below. During the assessments of the transmission circuits mentioned in Section 5.3.3.15 regarding transmission structure maintenance and replacement, the possibility to underground certain transmission circuits or portions of circuits in feasible locations is considered as part of a high level "alternative analysis."

Progress Timeline

- 1. **Before the upcoming wildfire season:** See Section 5.3.3.17 for a discussion of undergrounding distribution circuits.
- 2. **Before the next annual update:** See Section 5.3.3.17 for a discussion of undergrounding distribution circuits.
- 3. **Within the next 3 years:** See Section 5.3.3.17 for a discussion of undergrounding distribution circuits.
- 4. **Within the next 10 years:** See Section 5.3.3.17 for a discussion of undergrounding distribution circuits.

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

PG&E's initiatives to update grid topology to the minimize risk of wildfire ignition in HFTDs are gathered together under the rubric of System Hardening. Based on its experience of recent wildfires in its service area, benchmarking with other utilities, and its analysis of CPUC reportable ignitions on its system, PG&E developed design guidance for System Hardening, both for rebuilding areas that have experienced wildfires and for proactively hardening facilities in HFTD areas to reduce the risks and consequences of wildfire ignitions. In addition to procedures for hardening overhead circuits in place, PG&E's System Hardening program includes some targeted undergrounding of overhead circuits (for example, in order to protect critical egress routes or dense vegetation creates an especially high risk of trees falling into overhead lines).

5.3.3.17.1 System Hardening Design Guidance

Utility Bulletin: TD-9001B-009 Rev 2 "Fire Rebuild Design Guidance for System Hardening," which was first published on October 2, 2018 and continues to evolve, is based on several key foundational elements:¹⁵

- Primary Conductor Replacement: Replacement of bare overhead primary (high voltage) conductor and associated framing with conductor insulated with abrasion-resistant polyethylene coatings (sometimes referred to as covered conductor or tree wire). Installing covered conductor will help to further reduce the likelihood of faults due to line to line contacts, tree-branch contacts, and faults caused by animals.
- Secondary Conductor Replacement: Replacement of lower voltage (480V and below) conductor with insulated conductor. Installing covered conductor on secondary lines will have similar benefits to installing it on primary lines.
- Pole Replacements: All poles are evaluated for strength requirements to withstand new heavier covered conductor. Pole material is being evaluated for fire resiliency and strength.
- Replacement of Non-Exempt Equipment: Replacement of existing primary line equipment such as fuses/cutouts, and switches with equipment that has been certified by CAL FIRE as low fire risk. This replacement work will eliminate overhead line equipment and devices that may generate exposed electrical arcs, sparks or hot material during their operation.
- Replacement of Overhead Distribution Line Transformers: Upgrading transformers to FR3 Fluid as part of PG&E's current equipment standards (PG&E implemented the transition from mineral oil to FR3 in 2014). The newer transformers are filled with fire resistant FR3 insulating fluid, a natural ester derived from renewable vegetable oils—providing improved fire safety, transformer life, increased load capability, and environmental benefits. In addition, new transformers are manufactured to achieve higher Department of Energy electrical efficiency standards.
- Covered Conductor: Replacement of bare conductors with three-layer design of covered conductors (also known as tree wire) will reduce the likelihood of faults due to trees, branches, animals, or birds contacting lines, and will minimize situations where wires slap together in high winds, which can generate sparks or molten metal. The HFTD areas within PG&E's service territory have a high volume of vegetation with large overhangs and ground fuels; PG&E expects covered conductor to be an effective risk mitigation in these areas. The covered conductor will also often be higher gauge than the wire it replaces, which will reduce the potential for failures related to smaller conductors. PG&E is replacing bare

¹⁵ The requirements listed are current standard requirements to be used in new construction. The requirements outlined in this bulletin are not intended or required for maintenance and emergency work (unless the emergency is in follow-up to a fire event, requiring system re-build).

overhead distribution primary (high voltage) and secondary (low voltage) conductor with covered conductor in HFTD areas.

There is a limited risk that covered conductor may introduce higher impedance faults compared to bare conductor depending on how the conductor lands on the ground. However, an additional benefit of covered conductor is that it may be less likely to cause an ignition on the ground, as there is a lower potential for arc points along the line due to fewer contact points with the ground. Further, PG&E is currently piloting more sensitive protection for high impedance faults that may mitigate the additional high impedance risk. Additionally, PG&E is currently participating in two National Electric Energy Testing Research and Applications Center (NEETRAC) projects on covered conductors. One of these projects will focus on the available covered conductor technologies and point out known gaps in knowledge of covered conductor systems, outline the known advantage and disadvantages, and discuss the life cycle cost of installing covered conductors. The second project focus on the development of a fire initiation event trees from covered conductors. The purpose of this project is to codify knowledge of fire performance of the overhead distribution system including covered conductors using fault tree methodology; to establish composite industry event data, and to understand behavior and interactions.

- **Pole Replacements:** Due to the replacement of bare wire with heavier covered conductor, as well as the increased stringency of pole loading requirement discussed in Section 5.3.3.13 above, PG&E anticipates that most existing poles will need to be replaced in locations where System Hardening occurs. PG&E believes that it may be appropriate to use non-wood (e.g., steel or composite) poles for System Hardening applications because they may be more fire resistant/resilient. PG&E has been evaluating both wood and non-wood poles to determine which options are the most reasonable and effective. In 2019, PG&E, along with SDG&E and SCE, tested 11 different sets of poles (33 total) from 7 different manufacturers for fire resiliency via burn tests and fire prevention via simulated tree strikes. The poles tested include steel, ductile iron, concrete, composites with and without fire resistant coatings or coverings, and wood with fire resistant coverings. Results from the tree strike simulations yielded very similar system response for all poles tested and were comparable to typical wood poles. The burn tests similarly had relatively good results for most of the poles considered. PG&E will continue to evaluate these options, as well as considering other factors such as cost, availability, and longevity as it decides which poles to use in the System Hardening program.
- **Undergrounding:** As PG&E conducted inspections of portions of circuits planned for system hardening, it identified a number of circuits, or portions of circuits, in HFTD areas where it may be prudent and feasible to underground the overhead distribution lines. These circuits are typically in locations along main egress routes—that need to remain clear for first responders and evacuation 12 individuals—where a rebuilt overhead circuit could still pose a threat of 13 burned or downed poles blocking access in the event of a wildfire. Other circuits where undergrounding may be prudent involve areas with dense vegetation that pose an elevated risk of a tree fall onto an overhead line. PG&E has determined that in these instances, undergrounding of portions of circuits may be reasonable and prudent, and increases the safety of PG&E customers and the communities that it serves.

PG&E anticipates that only a relatively small proportion of the circuit miles included in the System Hardening Program will be undergrounded. The balance between overhead hardening and underground will be determined as the projects are scoped; the scoping process is described below.

PG&E plans use the procedures and equipment to underground facilities as part of the System Hardening program and it does for other undergrounding projects.

5.3.3.17.2 Distribution System Hardening

The Distribution System Hardening Program is an ongoing, long-term capital investment program to rebuild portions of PG&E's overhead electric distribution system. Under this program, PG&E is upgrading approximately 7,100 circuit miles in Tier 2 and Tier 3 HFTD areas.

In 2018, PG&E initiated construction pilots to evaluate various overhead conductor and equipment configurations, including potential undergrounding, as well as to develop best practices. In 2019, PG&E began the System Hardening Program proper, with a target of completing 150 circuit miles by the end of the year. In 2020-2022, PG&E forecasts completing approximately 1,000 distribution circuit miles (about 200 miles in 2020, approximately 350 in 2021 and 440 in 2022). PG&E ultimately intends to complete work on 7,100 distribution circuit miles.

The first work to be included in this program was certain work, such as conductor replacement projects and locations targeted by investigations by our outage review teams, that have been identified in the field prior the initiation of the program. To the extent these projects were located in Tier 2 and Tier 3 HFTD areas, PG&E updated their design consistent with the Fire Rebuild Design Guidance for System Hardening and incorporated it into the System Hardening plan.

A much larger portion of the plan is driven by fire-risk ignition modeling and a risk-informed prioritization approach for mitigation measures. This approach considered the following factors:

- Likelihood of Ignition: Ignition likelihood was determined based on a regression analysis predicting ignitions at the circuit level. This analysis considered:
 - Exposure (# of assets)
 - Failure Mode Analysis (Asset failure risk by asset type)
 - Asset condition (# of corrective notifications)
 - Historical incidents (# of outages and ignitions)
- Likelihood of Spread: Spread likelihood was determined based on a study conducted by PG&E and a third party. The fire spread analysis included:
 - Fuel type and density (grass vs. brush)
 - Topography (slope and natural fire breaks)
 - Weather/wind data
 - Distance from fire station / air suppression bases (speed to suppression)

- **Consequence:** Consequence focused on potential impact of a wildfire. The consequence scoring was based on:
 - Density of population
 - Density of structures
 - Potential negative impact to natural resources
- **Egress:** An analysis of the difficulty to access or evacuate communities. This egress analysis considered:
 - Population density of communities
 - Number and types of roads for each community.

Based on these analyses, PG&E developed an aggregated risk scoring to rank the relative risk score of different protection zones on circuits within the Tier 2 and Tier 3 HFTD. Analyzing this scoring further found that the top 26% rated protection zones cover the vast majority (98%) of the relative risk score total. These zones represent approximately 29% of the total HFTD circuit miles, consistent with PG&E's plan to address 7,100 circuit miles.

Another factor influencing the current prioritization of System Hardening projects is an analysis of the resulting Electric Corrective (EC) tags identified in the course of the WSIP. PG&E has determined that there are locations where a high density of EC tags coincide with areas that also scored highly in the risk ranking described above. To drive efficiency, reduce cost, and reduce resource demands, PG&E decided to create System Hardening projects in these areas, even if they are not the highest scoring areas in the risk ranking.

Going forward, PG&E hopes to further refine its risk modeling and prioritization in the in order to better target our work. As we review the relatively large protection zones included in the existing prioritization model, we realize that risk is not consistent within those zones. PG&E is looking for ways to create a more granular model so that with further analysis we can drive the risk scoring down to 3-5 mile sections of circuit. We hope to include other risks into the analysis including PSPS mitigation. If there are line sections that are regularly impacted by PSPS and expected to be impacted regularly in the future, what would be required in terms of hardening to exempt those lines from that risk mitigation tool? Currently, only undergrounding is exempt from PSPS. This is a very costly proposition and though these areas are not the highest risk in the system for catastrophic wildfires, when evaluated under our current risk models, they are a risk we must try to address to provide our customers the best service possible.

After determining which circuits should be included in the System Hardening program, PG&E must also determine whether those circuits should be rebuilt as hardened overhead circuits or should be undergrounded. This decision is made collaboratively as part of the initial field scoping process, which seeks to ensure a collaborative and inclusive discussion between our individual teams in an attempt to balance risk reduction, feasibility/constructability, and cost.

For each proposed System Hardening project, Distribution Engineers provide a basic scope to the team for initial review, and then a desktop meeting is scheduled to discuss the project as a team. Key questions we seek to answer in this meeting:

1. Can the overhead line be eliminated?
 - a. Is this line idle? Is there a redundant tie that can be removed without sacrificing operational flexibility?
2. Can the overhead line be placed underground?
 - a. Underground lines require a greater amount of space than overhead lines and are normally placed along main roadways. Considerations need to be made or the costs can inflate very quickly.
3. Can the overhead line equipment be relocated to a safer location?
 - a. If the line can be moved to a location that is more accessible and/or less exposed to ignition sources, it can significantly benefit both reliability and wildfire ignition risk reduction.
4. Is Hardening in place the best option for this location?

The normal attendees to this desktop meeting include: Project Management, Distribution Engineers, Estimating, Public Safety Specialists, Construction, Operations, Technology Application Support, Land, Environmental, Electric Vegetation Management, and Local Customer Experience. This cross-functional team seeks to form consensus on risks and mitigations, timelines and schedules, recommended routes, and the appropriate hardening construction methods.

After this desk-top meeting, estimating resources will go into the field to assess the locations we hope to utilize for this work to ensure any and all assumptions that were made in our discussion are vetted. This information feeds back into the determination of whether a line should be hardened in place or undergrounded; for example, detailed examination of the site may show that undergrounding would be cost prohibitive due to soil condition or other constraints.

5.3.3.17.3 Relationship Between System Hardening and Enhanced Vegetation Management

To better understand the interactions of multiple mitigations, PG&E previously performed a simple analysis of historical drivers of fire ignitions in HFTDs.¹⁶ System hardening (covered conductor plus pole replacement, exempt equipment and transformer replacement) was identified to mitigate 56% of the historical ignitions by itself. EVM was identified to mitigate 31% of the historical ignitions by itself. When combined, system hardening and EVM were together identified to mitigate 79% of historical ignitions. Because of this projected increase in mitigation when adding EVM to system hardening in HFTDs, PG&E is continuing to perform EVM in locations where system hardening has been completed. However, PG&E will go beyond such simple relationship analysis and is in the process of evaluating data from 2018 to the present to determine if, when these drivers are combined, there is in fact an increase in mitigation which outweighs any minimal redundancies and cost-inefficiencies. Should such understanding of the relationship between system hardening and EVM change, we may change our approach to EVM on system hardened lines.

5.3.3.17.4 Non-Exempt Surge Arrester Replacement Program

The replacement of non-exempt surge arresters with exempt surge arresters will further reduce fire risk since the new surge arresters are considered “non-expulsion” and do not generate arcs/sparks during normal operation. The surge arrester program is a multi-year program that forecasts to replace 8,850 surge arresters in Tier 2 and Tier 3 in 2020. Provisions are available to replace more units as material and crew resources become available throughout the year.

¹⁶ From a total of 414 ignitions in HFTD areas in years 2015-2017.

5.3.3.17.5 Transmission Line System Hardening Overview and Strategy

PG&E's Transmission Line System Hardening Program includes a number of elements intended to mitigate wildfire risk by reducing the risk of potential ignitions associated with PG&E's facilities and equipment. As a part of this program, PG&E is performing full line assessments for overhead electric transmission lines in HFTD areas to effectively evaluate the need of equipment replacement based on circuit risk.

To perform full line assessments, PG&E initiated the development of an asset health Operability Assessments (OA) tool to assess individual transmission lines and asset failures in HFTD areas due to wind loads. Through these OA, PG&E is applying a risk-informed methodology to evaluate the potential risks of the line, as well as individual assets, and prioritize replacements that will be most effective in hardening an individual line and the entire transmission system against high wind events and wildfire risk.

Progress Timeline

- 1. **Before the upcoming wildfire season:** PG&E will continue to scope and harden select distribution circuits in HFTD areas as describe above. PG&E will also continue to replace non-exempt surge arresters in HFTD areas. PG&E will continue to conduct Operability Assessments of transmission lines in HFTD areas.
- 2. **Before the next annual update:** See above. In addition, PG&E will continue to evaluate all of its programs to incorporate lessons learned from 2020, as well as any other relevant information, and may adjust its programs accordingly.
- 3. **Within the next 3 years:** See above.
- 4. **Within the next 10 years:** See above.

5.3.3.18 Other / Not Listed

5.3.3.18.1 Evaluating New Protection Technologies

PG&E is also evaluating different protection schemes and equipment that may further reduce the likelihood of a fire ignition when a system failure occurs. Below are three pilot projects to evaluate the effectiveness of new protection technologies and features.

- **High Impedance Fault Detection:** PG&E is piloting and proposes to deploy newer protection capabilities in reclosers and circuit breakers that increase the ability to detect high impedance faults. For reclosers, the downed conductor detection (DCD) feature in the Form 6 recloser and Beckwith controller is currently being piloted (200 plus reclosers) to alarm only in areas subject to outages during winter storms. The experience gained from this pilot will be used to create application guidelines for use in fire areas. Based on initial pilot results, DCD will be enabled in another 100 reclosers within the Tier 2 and 3 fire areas in 2020 to gain more experience in different terrain. In addition, a high impedance fault detection algorithm for feeder relays will be evaluated at ATS in the Q1 of 2020.
- **Increased Protection Sensitivity:** PG&E is evaluating the use of more sensitive protection settings and use faster tripping elements on reclosers and circuit breakers. The proposed settings and use of instantaneous elements that reduce the duration and energy delivered at a fault location. This may lower the potential for a fire ignition to occur. The proposed protection schemes, however, could reduce the ability to coordinate with downstream protective devices and will lead to an increase in the size and duration of outages.

5.3.3.18.2 Transmission Line Modeling

There are two ongoing modelling efforts to be highlighted regarding PG&E's transmission system.

- One aspect of that managing the operation and maintenance of transmission infrastructure is assessing the condition (health) of the components and structures and evaluating the increased risk of failure associated with known degradation mechanisms or aging in general. PG&E has developed a comprehensive, analytical framework for OA, which assesses the physical condition of overhead electrical transmission line assets. This tool informs both asset management and operability assessment decisions and incorporates elements of probabilistic risk assessment commonly used in other industries such as nuclear power generation.

Key to understanding the OA tool is the concept of fragility. In short, fragility refers to the increasing probability of failure for increasing applied load. In the context of the OA tool, fragility is the conditional probability that an asset (tower, pole, conductor, anchor, etc.) will fail at a given wind speed. While wind speed is the intensity measure used to define fragility, the OA tool considers many damage mechanisms such as corrosion, fatigue, wear and decay that can lower the capacity of the asset to resist wind loads.

The OA tool is based on assigning a fragility curve to each asset to reflect its current health relative to a newly designed and constructed, but otherwise identical, asset. This is done by first presuming a fragility associated with a new, healthy asset, and then adjusting both the strength and uncertainty to reflect the observed condition, age, environment, and historical performance of the circuit in whole. Specifically, the median strength is adjusted based on ground and drone inspection results, test and treat inspection findings (for wood poles only), and structural engineering analysis of the towers/poles, insulators, guys, foundations, anchors and conductors. The uncertainty is adjusted based on the asset age versus a notional design life, the aggressiveness of the asset environment with respect to corrosion and windiness, and the past performance of the circuit.

For OA, the fragility can be used to predict the risk that an asset (or set of assets) will underperform at a forecast wind speed. Alternately, if a risk tolerance is defined, the corresponding wind speed at which that tolerance is exceeded can be determined directly from the fragility as described earlier. The risk tolerance is an input to the OA tool, and is a function of many concerns outside the scope of the OA tool.

- The OA tool also includes a mechanism for continuous improvement of wind-based asset strength estimation. Past and on-going component failures and survivals of assets in windy conditions are incorporated into the model using Bayesian updating methodologies. Further, PG&E is undertaking a testing program to better define fragility curves for specific components. Lastly, prediction data for every structure on a given circuit (both historical and going forward) is being integrated into the OA tool for increased accuracy. The result will be a tool that assists PG&E with risk-informed decisions based on expected future strength and uncertainty of PG&E transmission assets. Individual health models to determine probability of failure were developed for major transmission asset types. The probability of failure models were developed using multiple inputs including but not limited to past

performance history, maintenance work performed, condition, age, and location. The model then outputs an expected probability of failure along with the main drivers associated with the probability. Information such as this allows PG&E to gain a more granular perspective on asset repair and replacement. These asset-based models may also be aggregated to create a circuit-based probability of failure model.

- The above-mentioned OA and asset health models are used to inform asset decision making (e.g., replacement of towers as in Section 5.3.3.15, or PSPS in Section 5.6.2.2). These existing models will continually be improved upon as new data becomes available.

Progress Timeline

1. **Before the upcoming wildfire season:** See above discussion regarding timing for review and evaluation of new protection technologies and modeling.
2. **Before the next annual update:** See above.
3. **Within the next 3 years:** See above.
4. **Within the next 10 years:** See above.

5.3.3.18.3 – Building and Sourcing Services

Building services supports the WMP initiatives in two primary ways: (1) securing office space for employees and contractors supporting the WMP initiatives; and (2) securing yards and staging areas for materials needed to complete WMP work.

Sourcing provides strategic, operational, and execution level support of PG&E's WMP. Sourcing provides sourcing program management support, develops project plans, and coordinates sourcing activities with cross functional teams. Sourcing support includes but is not limited to facilitating supplier evaluations, contract bidding and bid awards processes, and direct negotiations. Placement in Section 5.3.3 is based on the desire to put these services within the Section 5.3 initiatives, but note the services support all the WMP initiatives.

Formatted: Body Text, Space Before: 6 pt

5.3.4 Asset Management and Inspections

Explain the rationale for any utility ignition probability-specific inspections (e.g., "enhanced inspections") within the HFTD as deemed necessary over and above the standard inspections. This shall include information about how (i.e., criteria, protocols, etc.) the electrical corporation determines additional inspections are necessary.

Describe the utility's maintenance protocols relating to maintenance of any electric lines or equipment that could, directly or indirectly, relate to wildfire ignition. Include in the description the threshold by which the utility makes decisions of whether to (1) repair, or (2) replace electric lines and equipment. Describe all electric lines and equipment that the utility "runs-to-failure", those that the utility maintains on a risk-based maintenance plan, and those that are managed by other approaches; describe each approach. Explain the maintenance program that the utility follows and rationale for all lines and equipment.

Description of programs to reduce ignition probability and wildfire consequence

For each of the below initiatives, provide a detailed description and approximate timeline of each, whether already implemented or planned, to minimize the risk of its equipment or facilities causing wildfires. Include a description for the utility's programs, the utility's rationale behind each of the elements of this program, the utility's prioritization approach/methodology to determine spending and deployment of human and other resources, how the utility will conduct audits or other quality checks on each program, how the utility plans to demonstrate over time whether each component is effective and, if not, how the utility plans to evolve each component to ensure effective spend of ratepayer funds.

Include descriptions across each of the following initiatives. Input the following initiative names into a spreadsheet formatted according to the template below and input information for each cell in the row.

- 1. Detailed inspections of distribution electric lines and equipment
- 2. Detailed inspections of transmission electric lines and equipment
- 3. Improvement of inspections
- 4. Infrared inspections of distribution electric lines and equipment
- 5. Infrared inspections of transmission electric lines and equipment
- 6. Intrusive pole inspections
- 7. LiDAR inspections of distribution electric lines and equipment
- 8. LiDAR inspections of transmission electric lines and equipment
- 9. Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations

- 10. *Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations*
- 11. *Patrol inspections of distribution electric lines and equipment*
- 12. *Patrol inspections of transmission electric lines and equipment*
- 13. *Pole loading assessment program to determine safety factor*
- 14. *Quality assurance / quality control of inspections*
- 15. *Substation inspections*
- 16. *Other / not listed [only if an initiative cannot feasibly be classified within those listed above]*

PG&E’s maintenance programs are described in Section 5.3.3. Below is a description of PG&E’s Asset Management Program and Inspection Programs.

Overview of PG&E’s Asset Management Program and Inspection Program

PG&E’s distribution asset strategies are described in its Asset Management Plans (AMPs). PG&E employs a risk-based asset management approach for its overhead facilities, which includes criticality of the assets. Generally speaking, there are two main approaches with respect to asset replacement: Proactive Replacement and Run to Condition, which are described in more detail below. PG&E is also including below an overview of its inspection programs generally and, in particular, Wildfire Safety Inspection Program (WSIP).

Proactive Replacement

Proactive replacement is employed for those assets whose failure have a higher risk of igniting a catastrophic wildfire. This approach involves replacing assets with a higher risk of failure, but before the end of their useful life. The following are proactive replacement programs:

- System Hardening in HFTDs (including replacing existing assets with covered conductor [primary and secondary], stronger poles, non-exempt equipment, transformers with FR3 oil, as well as undergrounding)
- Pole Replacement and Reinforcement
- Primary Conductor Replacement
- Non-Exempt Equipment Replacement (Fuses and Surge Arresters)

Run to Condition

Run to condition repair/replacement is employed for those assets whose failure have a lower risk of igniting a catastrophic wildfire. This approach involves routine and non-

routine inspections focused on the identification, assessment, prioritization, and documentation of compelling abnormal conditions, regulatory conditions, and third party caused infractions that negatively impact safety or reliability. These conditions are identified during patrols and inspections of PG&E's distribution facilities, and may occur as a result of operational use, degradation, environmental changes or third-party actions. The following assets are subject to Run to Condition:

- Crossarms, insulators and pole hardware
- Voltage regulating equipment
- Protection equipment
- Transformers
- Switching Equipment
- Secondary Conductor

Inspection Program

PG&E utilizes multiple means of assessment to proactively monitor the condition of its assets in HFTD areas. The pre-2019 baseline inspection program was primarily focused on the identification, assessment, prioritization, and documentation of compelling abnormal conditions, regulatory conditions, and third-party caused infractions that negatively impacted safety or reliability. These conditions may occur as a result of operational use, degradation, deterioration, environmental changes or third-party actions. PG&E routinely assesses its distribution, transmission, and substation assets using a variety of methods, including observations when performing work in the area, periodic patrols and inspections, and targeted condition-based and/or diagnostic testing and monitoring. Some of PG&E's current inspection approaches have been in place for years, while others are newer in their implementation. Common inspection approaches used at PG&E include routine patrol inspections, detailed visual inspections, LIDAR inspections, Infrared (IR) inspections, Intrusive pole inspections, and pole loading calculations. These routine assessments of PG&E's overhead and underground electric systems, including its electric substation inspections, are designed in accordance with GOs 95, 165, and 174 requirements.

In 2019, PG&E began a Wildfire Safety Inspection Program or "WSIP" to expedite and expand the routine detailed inspections performed in Tier 2 and Tier 3 HFTD areas. Basic elements include travel to the asset, ground and or aerial visual observation documented with electronic form (checklist) and with pictures, detection and assessment of abnormal conditions, corrective notification creation, prioritization and execution of repairs, and documentation needed for safe and reliable operation. To develop the WSIP inspection checklist, PG&E used a risk-based approach including conducting a Failure Modes and Effects Analysis or "FMEA" (described in further detail in Section 5.3.1). The 2019 focus of the FMEA was to identify single points of failure of electric system components that could lead to fire ignition and then aid in the development of inspection methods that can most appropriately identify the condition of these respective components.

In the last half of 2019, PG&E worked to refine the FMEA a for each major overhead electric asset family (transmission, distribution, and substation) to create detailed inspection checklists appropriate to the failure modes which can create ignition potential as well as other negative outcomes.

Going forward, the detailed overhead inspection checklists will be consistently applied to all assets of an asset family. This means that overhead detailed compliance inspections have largely been coupled to the fire ignition evaluation protocols, rather than being separately funded and managed. Additionally, PG&E has begun evaluation and development of circuit-based asset management strategies, which seek to focus resources of various types, including inspections, on assets with higher risk profiles. As PG&E gathers additional data regarding early asset deterioration or pre-failure indicators, predictive failure modelling may improve. Such evolved predictive models could utilize data on vegetation and equipment type, age, and condition. Over time, it is possible that detailed asset inspection checklists may be customized to align with asset condition and environmental data as indicated by those models.

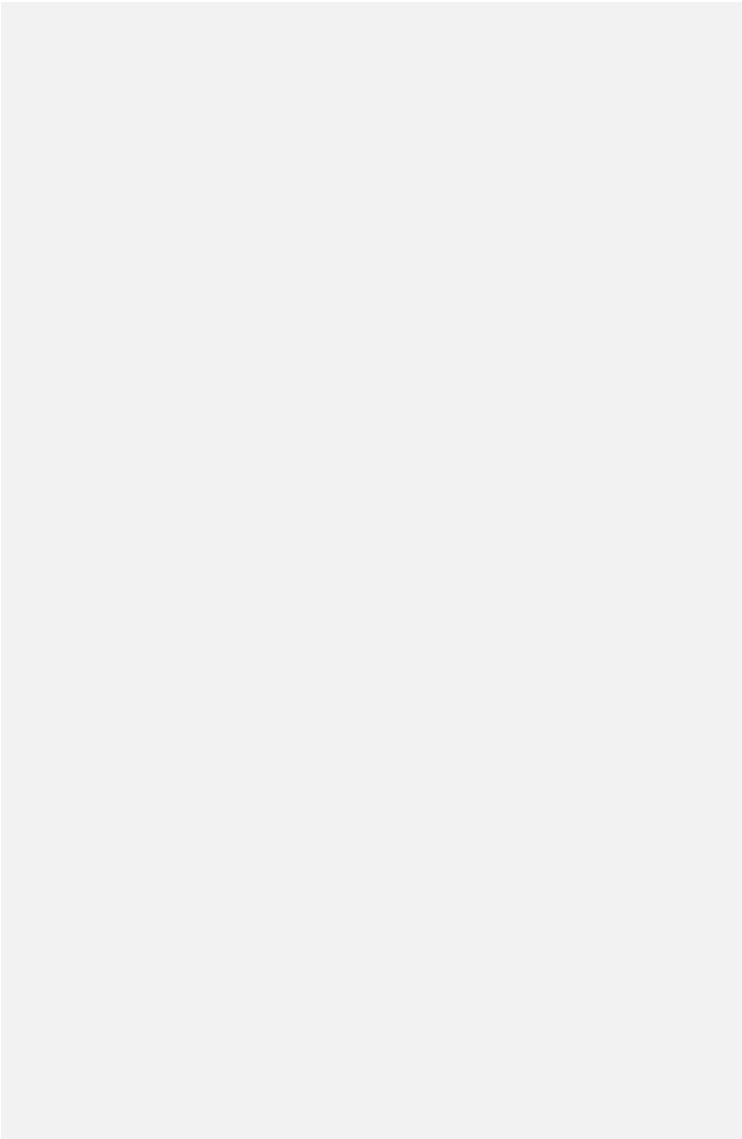
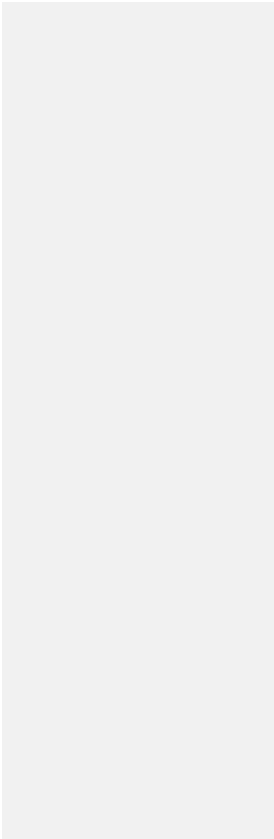
PG&E's detailed and supplemental inspections and patrols are guided by the inventory of electric facilities in our Geographic Information System (GIS). The overlay of facility type, asset health, geographic risk factors are considered when determining the most appropriate patrol and inspection cycle for the asset or circuit. Recognizing the importance of GIS, PG&E continues to improve its GIS data, including designating single points of contact at PG&E for all wildfire-related GIS needs. To refine PG&E's PSPS models and GIS datasets, during supplemental (enhanced) inspections, each inspector utilizes a consistent assessment checklist, validates certain asset traits, and makes a guided assessment of the asset condition. In addition, the electronic checklist captures a geolocation at the time of inspection initiation, which may be used to reaffirm the existing geolocation data in PG&E's systems of record. This data is captured in PG&E's systems of record and made available for PSPS event impact modelling, among other uses.

Expansion of data collection during post-asset failure, detail inspections, and other advanced inspection methods are expected to further refine PG&E's ability to assess equipment health. PG&E continues to build capabilities for predictive asset performance modelling via tools such as System Tool for Asset Risk (STAR). The STAR model supports decisions on when to schedule inspections or work for higher risk assets in other areas, based on factors beyond fire ignition risk. The shift towards such condition-based and risk-informed patrol and inspections is underway and will be refined as PG&E acquires additional asset performance data and refines its predictive failure models based on actual results. Further details of specific inspection protocols are provided in subsequent tables and narrative.

PG&E continues to work to enhance its ability to efficiently collect and house asset registry data, including the results of patrol and inspection activities. Detailed inspection protocols and electronic tools planned for use in 2020 and beyond, link to the inventory of electric assets in the GIS, and data collected via detail inspection will be captured in SAP. By harmonizing our core data sources (SAP and GIS, for example) the results of asset activities (installation, repair, replacement, inspection) can be made consistently available to all programs and models. Future enhancements to predictive models could include asset age, state of wear, operating history, expected lifecycle, and probability of

failure to inform patrol and inspection cycles as well as asset repair and replacement programs.

See Attachment 1, Table 24 for the details and data associated with the initiatives discussed in this section.



5.3.4.1 Detailed Inspections of Distribution Electric Lines and Equipment

Detailed inspections of distribution electric lines and equipment involves careful visual examination of overhead assets by a qualified Compliance Inspector or similar Journeyman Lineman in accordance with the TD-2305M (Electric Distribution Preventive Maintenance Manual, EDPM). Before conducting patrols or inspections, PG&E Compliance Inspectors, hiring hall, and contract personnel are required to be current with their journeymen classification and pass trainings and assessment. The program is moving from a prescriptive time cycle frequency to an approach driven by risk, with the highest risk assets requiring more frequent and in-depth inspections than lower risk assets. Aligned with the overall risk-informed approach for asset management, inspection priority is driven by asset health and consequences of asset failures. As a result of this approach, it is anticipated to have selective Structures/Lines with high consequence that will require a higher degree of inspections.

For 2020, PG&E intends to perform detailed overhead inspections on 100% of HFTD Tier 3, and 33% of HFTD Tier 2 assets. Additional inspections in HFTD Tier 2 may result from operational execution and from safety field re-assessments of open corrective notifications, as outlined in the WSIP Compliance Plan and Utility Bulletin: TD-8999B-001. Future year inspection scope will be developed to align with overall asset preventive maintenance strategies and will be informed by results of the 2020 preventive and corrective maintenance activities. Future year cycles may shift toward risk-informed and condition-dependent cycles linked to PG&E predictive models. Methods and tools of inspections will continue being evaluated for potential future use depending on technology availability and effectiveness.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E will expand its use of prescriptive mobile inspection checklists to overhead assets in all HFTD tiers. Additionally, PG&E will have expanded the FMEA completed for WSIP Distribution 2019, to incorporate additional asset failure indicators which are observable during visual inspection.
2. **Before the next annual update:** PG&E will review the results of the 2020 detailed inspections and consider modifying future inspection checklists and guidance documents to reflect lessons learned.
3. **Within the next 3 years:** PG&E plans to move all electric patrol and inspection activities to digital data collection platforms (e.g., mobile applications) and away from paper record keeping. PG&E will revisit the commonalities of transmission and distribution overhead asset inspections with the intent to consolidate tools, methods, and personnel qualifications. PG&E will also determine if adjusting asset inspection cycles or modalities is likely to have adverse impacts on system safety or performance.
4. **Within the next 10 years:** PG&E anticipates moving to a risk-informed circuit-based inspection protocol that prescribes the timing for preventive maintenance activities aligned to multiple asset and environmental factors. This may shift the percentage of total annual structures and line miles away from the current proposal.

5.3.4.2 Detailed Inspections of Transmission Electric Lines and Equipment

Detailed inspections of transmission electric lines and equipment involves careful visual examination of overhead assets by a qualified Transmission Troubleshooter/Inspector or similar Journeyman Lineman in accordance with the TD-1001M (Electric Transmission Preventive Maintenance Manual, ETPM). Before conducting patrols or inspections, PG&E inspectors, hiring hall, and contract personnel are required to be current with their journeymen classification and pass trainings and assessment. In connection with WSIP, PG&E formulated certain new procedures to guide WSIP enhanced inspections and updated existing procedures. Additionally, mobile applications were developed to document the inspection activity and resulting findings.

In late 2018, PG&E conducted an FMEA of transmission assets to better understand any additional inspections and analysis that could be implemented to reduce wildfire risk in addition to the inspections required by GCOs 95 and 165. Beginning in December 2018, using this risk-based approach, PG&E performed inspections of transmission structures (poles and towers) in HFTD areas, as well as nearby structures outside the HFTD in close proximity and with high risk of fire spread into adjacent HFTD areas (approximately 5,700 miles of transmission line with more than 50,000 structures). These enhanced inspections focused on the failure mechanisms identified from the FMEA based on PG&E and industry information that identified components with a fire ignition risk. The visual inspections included checklist-guided ground inspection of transmission poles and climbing inspection of transmission towers. Aerial inspections were conducted on every structure in the WSIP scope, subject to any FAA or other legal restrictions, to complement the ground and climbing visual inspections. Helicopters were also used for additional aerial inspections for collecting infrared data to determine hot spots on conductors, insulators, and connectors requiring repair.

From 2020 onward, the detailed inspection checklist for electric transmission lines and equipment has been updated to incorporate baseline compliance guidelines as well as WSIP-identified fire risk considerations, and extensions to the FMEA. Additionally, detailed inspections of electric transmission lines have been coupled with aerial inspection methods to provide the additional aloft vantage points for each structure assessed during a given cycle. The program is moving from a prescriptive time cycle frequency to an approach driven by risk, with the highest risk assets requiring more frequent and in-depth inspections than lower risk assets. Aligned with the overall risk-informed approach for asset management, inspection priority is driven by asset health and consequences of asset failures. As a result of this approach, it is anticipated to have selective Structures/Lines with high consequence that will require a higher degree of inspections. The inspection frequency of assets varies by both HFTD and line risk prioritization and will continue to evolve as models are refined. For 2020, PG&E intends to perform detailed overhead inspections on 100% of HFTD Tier 3, and 33% of HFTD Tier 2 assets. Additional inspections may result from operational execution and from safety field re-assessments of open corrective notifications, as outlined in the WSIP Compliance Plan and Utility Bulletin: TD-8999B-001. Results from these inspection cycles will be used to further refine the inspection methods and recurrence to align with their risk-spend efficiency. Methods and tools of inspections will continue being evaluated for potential future use depending on technology availability and effectiveness.

Quality checks of transmission detailed inspection tasks was previously completed via supervisor work verification and paperwork review. From 2019 onward, PG&E adopted a practice of centralized gatekeeping review of inspection findings. The centralized gatekeeper teams follow prescriptive guidance, including decision trees and use visual aids to drive consistency in their review of issues reported during inspections.

Progress Timeline

- 1. **Before the upcoming wildfire season:** PG&E will have expanded the FMEA completed for WSIP Transmission 2019, to incorporate additional asset failure indicators which are observable during visual inspection.
- 2. **Before the next annual update:** PG&E will review the results of the 2020 detailed inspections and consider modifying future inspection checklists and guidance documents to reflect lessons learned.
- 3. **Within the next 3 years:** PG&E plans to move all electric patrol and inspection activities to digital data collection platforms (e.g., mobile applications) and away from paper record keeping. PG&E will revisit the commonalities of transmission and distribution overhead asset inspections with the intent to consolidate tools, methods, and personnel qualifications. PG&E will also determine if adjusting asset inspection cycles or modalities is likely to have adverse impacts on system safety or performance.
- 4. **Within the next 10 years:** PG&E anticipates moving to a risk-informed circuit-based inspection protocol that prescribes the timing for preventive maintenance activities aligned to multiple asset and environmental factors. This may shift the percentage of total annual structures and line miles away from the current proposal.

5.3.4.3 Improvement of Inspections

Improvement of inspections is accomplished via review of audit and quality assurance findings, executive reviews, and internal guidance (GOV-1038S) which highlight areas of opportunity. Improvement in inspections may focus on one or more of: efficacy in proactive detection of asset anomalies, consistency in identifying or classifying asset anomalies, efficiency in providing quality inspection results. In the near-term, improvement of inspections will seek to apply internal best practices identified during WSIP 2019 consistently across the asset families (transmission, distribution, and substation). For example, the transmission approach to inspection gatekeeping via Centralized Inspection Review Team (CIRT) is being more broadly adopted for distribution. And, the use of gatekeeper decision trees and other job aids that support more consistent evaluation and prioritization of inspection findings. Improvement may also take on the form of enhancing tools and documentation that guide the activity, such as mobile electronic checklists. Concurrent with expanded deployment of mobile inspection applications and tools, PG&E will develop process control measures (data analysis) to more rapidly assess for abnormalities in patrol and inspection findings. Additionally, exploration of new or novel inspection protocols may also lead to improvements in inspection program efficacy, consistency, or efficiency.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E will have expanded the FMEA completed for WSIP 2019 to incorporate additional asset failure indicators which are visible during inspection. PG&E will have established baseline inspection quality control measures to proactively highlight abnormal results and drive corrective activities.
2. **Before the next annual update:** PG&E will review the results of the 2020 detailed inspections and consider modifying future inspection checklists and guidance documents to reflect lessons learned. PG&E anticipates completing a pilot of new inspection protocols (Ultrasonic) to assess its efficacy and efficiency in identifying abnormal conditions as compared to detailed visual inspections.
3. **Within the next 3 years:** PG&E plans to move all electric patrol and inspection activities to digital data collection platforms (e.g., mobile applications) and away from paper record keeping. PG&E will revisit the commonalities of transmission and distribution overhead asset inspections with the intent to consolidate tools, methods, and personnel qualifications. PG&E will also determine if adjusting asset inspection cycles or modalities is likely to have adverse impacts on system safety or performance.
4. **Within the next 10 years:** PG&E anticipates moving to a risk-informed circuit-based inspection protocol that prescribes the timing for preventive maintenance activities aligned to multiple asset and environmental factors. PG&E may also pilot additional patrol or inspection modalities not yet in common usage at the utility.

5.3.4.4 Infrared Inspections of Distribution Electric Lines and Equipment

Infrared inspections of distribution electric lines and equipment began in 2012 as means to identify system components and in-line conductor splices that require repair and/or replacement. Electric distribution preventive maintenance programs use IR imaging and temperature-measuring systems to identify faulty components and initiate repairs or replacement proactively. IR imaging systems detect and record heat being radiated in their fields of view. IR cameras use an image-scanning technique to identify heat radiated from a target and its background. IR imaging systems capture and store the heat images pictorially for immediate or future evaluation. By using IR imaging systems, the operator can pinpoint the precise location of the hottest spot on the target being observed. Distribution IR program utilizes trained contractors to identify hot spots (abnormal temperature) for corrective action. IR assessment potentially prevents wire down equipment failures and helps pinpoint areas for maintenance and conductor replacement. Any findings are coupled with the IR image and SAP corrective maintenance tags are created and prioritized in accordance with TD-2022P-01.

Going forward , infrared inspections will be deployed as appropriate alongside the suite of other inspection tools and techniques include enhanced visual inspections, drones or helicopters and other emerging technologies. PG&E does not have a discrete plan for how many circuit miles will be inspected using IR systems in HFTD areas. One of several reasons that IR inspections will be deployed in a targeted manner is that the effectiveness of IR inspections can be heavily influenced by the level of electric load in the lines being inspected. If the electric load is low, it can be more difficult to capture meaningful data through IR inspections. As such PG&E is continuing to evaluate the effectiveness of various inspection methods, when performed, IR work is tracked by line miles inspected, and findings per 100 miles inspected. In addition, to the vendor's QC program, PG&E receives the work product weekly and reviews the records prior to any invoice approvals.

Progress Timeline

- 1. **Before the upcoming wildfire season:** Apply IR distribution inspections as determined to be appropriate as part of the overall asset inspection program as described above. No enhancements are planned before the upcoming wildfire season.
- 2. **Before the next annual update:** Continue evaluating IR alongside other inspection methods to optimize overall asset inspection approaches, particularly in HFTD Tiers 2 and 3.
- 3. **Within the next 3 years:** PG&E will begin utilizing predictive modelling to identify and schedule inspections for higher risk conductors in other areas. The model will factor in the conditions of the conductor based on the results of its last inspection and other factors such as age, weather, and loading to develop the risk profile.
- 4. **Within the next 10 years:** No specific refinements are planned aside from continued enhancements to the predictive models.

5.3.4.5 Infrared Inspections of Transmission Electric Lines and Equipment

Infrared (IR) inspection is an effective tool within the transmission overhead preventive maintenance program. IR inspection reduces the potential for component failures and facility damage and facilitates a proactive approach to identifying abnormal components and conductor for repair/or replacement. Electric transmission system inspections and preventive maintenance programs use IR imaging and temperature-measuring systems to identify faulty components and initiate repairs or replacement proactively. IR imaging systems detect and record heat being radiated in their fields of view. IR cameras use an image-scanning technique to identify heat radiated from a target and its background. IR imaging systems capture and store the heat images pictorially for immediate or future evaluation. By using IR imaging systems, the operator can pinpoint the precise location of the hottest spot on the target being observed.

Going forward, infrared inspections will be deployed as appropriate alongside the suite of other inspection tools and techniques which include enhanced visual inspections, drones or helicopters and other emerging technologies. PG&E does not have a discrete plan for how many circuit miles will be inspected using IR systems in HFTD areas. One of several reasons that IR inspections will be deployed in a targeted manner is that the effectiveness of IR inspections can be heavily influenced by the level of electric load in the lines being inspected. If the electric load is low, it can be more difficult to capture meaningful data through IR inspections. As such PG&E is continuing to evaluate the effectiveness of various inspection methods.

Progress Timeline

1. **Before the upcoming wildfire season:** Apply IR inspections as determined to be appropriate as part of the overall asset inspection program as described above. No enhancements are planned before the upcoming wildfire season.
2. **Before the next annual update:** Continue evaluating IR alongside other inspection methods to optimize overall asset inspection approaches, particularly in HFTD Tiers 2 and 3.
3. **Within the next 3 years:** PG&E will begin utilizing predictive modelling to identify and schedule inspections for higher risk conductors in all areas. The model will factor conditions of the conductor based on factors such as condition, environment, design and age to develop the risk profile.
4. **Within the next 10 years:** No specific refinements are planned aside from continued enhancements to the predictive models.

5.3.4.6 Intrusive Pole Inspections

Intrusive pole inspections, also called Pole Test and Treat (PT&T), intrusively inspects in-service wood poles on an approximate 10-year cycle for early detection of deterioration. PT&T prolongs the service life of wood poles through reapplication of preservative and/or restoration of structural strength through reinforcement. PT&T identifies poles that are nearing the end of their service life and recommends these poles for replacement prior to failure. PG&E's PT&T program has existed since 1994 and is fully implemented across transmission and distribution wood pole structures. PG&E contracts out the execution of intrusive pole inspections to a specialized contractor who performs this work for other utilities as well. QA is provided through sampling and reinspection by internal PG&E personnel, as well as the vendor performance reports. PT&T has its own QA program of the inspections. PG&E Internal Audits department performs audits as requested or recommended, in accordance with their requirements.

Progress Timeline

- 1. *Before the upcoming wildfire season:* No enhancements are planned.
- 2. *Before the next annual update:* No enhancements are planned.
- 3. *Within the next 3 years:* A mobile inspection platform aligned to other PG&E inspection programs is anticipated to be adopted.
- 4. *Within the next 10 years:* PG&E anticipates moving to a risk-informed circuit-based inspection protocol that prescribes the timing for preventive maintenance activities aligned to multiple asset and environmental factors, which may shift the frequency away from the current forecast.

5.3.4.7 LIDAR Inspections of Distribution Electric Lines and Equipment

LIDAR technology has been used to varying degrees at PG&E since 2015. See Section 5.3.5.7 for more on VM related LIDAR inspections along distribution electric lines and equipment.

For 2020, the project objective is to leverage the remote sensing data already gathered to produce more advanced analytics to proactively identify distribution circuit spans or regions where the risk from encroaching vegetation is greatest. PG&E's LIDAR acquisition and data processing vendor is performing quality control before delivery of results to PG&E. These Quality Control steps include manually reviewing the data to look for gaps in acquisition coverage, incorrect classification of assets and inconsistencies in what was delivered to the Vendor from PG&E's EDGIS data. Data Quality Control is being performed by PG&E's IT Department. In addition, samples of the deliverables are being reviewed by contract Foresters in the field. PG&E end users across the system will have the ability to "validate" the individual LIDAR tree points before prescribing work. As the implementation of LIDAR and remote sensing continues to progress, LIDAR derived Electric Asset Layers can also be utilized by all Electric Operations teams (Service Planners, Trouble teams, Emergency Operations Teams, etc.) in their planning activities.

Progress Timeline

1. **Before the upcoming wildfire season:** Continue implementing the LIDAR inspection program on distribution lines and equipment as described above. No enhancements are anticipated before the upcoming wildfire season.
2. **Before the next annual update:** PG&E will begin utilizing data captured by Vegetation Management personnel for any new circuits not already having any amount of completed work within the EVM program. This data will include:
(1) LIDAR derived "Strike Tree" inventory that field inspectors can then utilize as a baseline for trees that need assessments and (2) LIDAR derived Electric Asset Layer that better portrays spatially where our Electric Assets are located; and
3. **Within the next 3 years:** PG&E will continue to compare LIDAR data to other data points such as weather patterns and outage histories to create a deeper data set that can be updated over time. This will enable PG&E to create updated risk profiles based on circuits, regions, or even at a span by span level, to enhance our predictive models over time.
4. **Within the next 10 years:** PG&E anticipates moving to a risk-informed circuit-based inspection protocol that prescribes the timing for preventive maintenance activities aligned to multiple asset and environmental factors, which may shift the frequency away from the current forecast.

5.3.4.8 LIDAR Inspections of Transmission Electric Lines and Equipment

LIDAR technology is used to determine vegetation conditions, predominantly distances and clearances, in relation to the electric conductors and easement boundaries. LIDAR programs provide span-level details of vegetation encroachment and other hazards such as fall in and grow in risk. LIDAR is also used to assess conformance with Minimum Ground to Conductor Clearance (Rule 37 MGCC) – the closest the lines can sag to the ground based on clearances listed in General Order 95, Rule37, Table 1, and Case 4. The LIDAR data provided is specific to a corridor width defined by voltage, increasing with voltage. LIDAR inspections of transmission electric lines and equipment is currently performed under contract as part of the Transmission Vegetation Management for the benefit of both vegetation management programs as well as asset preventive maintenance programs. The execution of LIDAR inspections is guided by Bulletin [TD-7103B-003](#) which outlines the types of data provided, assessments undertaken, operational tracking, and priority assignment of findings.

Progress Timeline

1. **Before the upcoming wildfire season:** Continue implementing the LIDAR inspection program on transmission lines and equipment as described above. No enhancements are anticipated before the upcoming wildfire season.
2. **Before the next annual update:** PG&E will begin utilizing data captured by VM personnel for any new circuits not already having any amount of completed work within the EVM program. This data will include: (1) LIDAR derived "Strike Tree" inventory that field inspectors can then utilize as a baseline for trees that need assessments; (2) LIDAR derived Electric Asset Layer that better portrays spatially where our Electric Assets are located; and (3) Potentially an advanced reporting program that better portrays where we may have encroachment issues with our internal and external requirements for clearances.
3. **Within the next 3 years:** PG&E will continue to compare LIDAR data to other data points such as weather patterns and outage histories to create a deeper data set that can be updated over time. This will enable PG&E to create updated risk profiles based on circuits, regions, or even at a span by span level, to enhance our predictive models over time.
4. **Within the next 10 years:** PG&E anticipates moving to a risk-informed circuit-based inspection protocol that prescribes the timing for preventive maintenance activities aligned to multiple asset and environmental factors, which may shift the frequency away from the current forecast.

5.3.4.9 Other Discretionary Inspection of Distribution Electric Lines and Equipment, Beyond Inspections Mandated by Rules and Regulations

Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations currently includes Ultrasonic (UT), new to PG&E in 2020. Ultrasonic inspection technology is being piloted in 2020 for overhead Transmission and Distribution assets to validate the technology's ability to proactively identify abnormal electrical discharge in components and determine relative suitability as a complimentary inspection technique to existing methods. PG&E plans to conduct laboratory and field testing of the technology, which has been commercialized by an international firm, and used by other US-based utilities. The scope of the field pilot for transmission and distribution assets is being finalized. As more data is gathered, PG&E will assess the value of continuing these technologies as supplements to other visual inspection techniques. If determined that Ultrasonic technology provides value, then PG&E will establish process for UT inspection that can be operationalized for future production inspections and incorporate UT inspection findings into our asset risk models (FMEAs), as needed. [Ultrasonic inspection is included in the details and data associated with Attachment 1, Table 24 Section 12, Patrol inspections of transmission electric lines and equipment.](#)

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E will commence a pilot of Ultrasonic technology in both transmission and distribution.
2. **Before the next annual update:** PG&E will determine whether to adopt or expand the use of Ultrasonic technology, and in what scenarios.
3. **Within the next 3 years:** PG&E will benchmark other utilities to identify other emerging technologies to enhance the inspection protocols.
4. **Within the next 10 years:** PG&E may develop asset or component-specific examination protocols that are proactively prescribed based upon predictive asset failure modelling.

5.3.4.10 Other Discretionary Inspection of Transmission Electric Lines and Equipment, Beyond Inspections Mandated by Rules and Regulations

Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations currently includes aerial high-definition photo capture of asset via drone (e.g., unmanned aerial vehicles, UAV) or specially-equipped helicopters. Aerial imagery capture was piloted at scale during WSIP 2019 for transmission lines and substations in Tier 2 and Tier 3 HFTD areas. Images are captured by UAV or helicopter pilots and transferred electronically to qualified journeymen inspectors to review for anomalies in accordance to the detailed inspection checklist. The viewing angles provided by UAV and helicopter are not readily achieved via ground-based detailed inspections, even with viewing magnification.

Another approach new to PG&E in 2020 is Ultrasonic assessment of energized overhead assets. Ultrasonic inspection technology is being tested piloted in 2020 for overhead Transmission and Distribution assets to validate the technology's ability to proactively identify abnormal electrical discharge in components and determine its relative suitability as a complimentary inspection technique to existing visual inspection methods. PG&E plans to conduct laboratory and field testing of the technology, which has been commercialized by a South Korean firm. The scope of the field pilot for transmission and distribution assets is being finalized. As more data is gathered, PG&E will assess the value of continuing these technologies as supplements to other visual inspection techniques.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E will commence a pilot of Ultrasonic technology in both transmission and distribution.
2. **Before the next annual update:** PG&E will determine whether to adopt or expand the use of Ultrasonic technology, and under what scenarios.
3. **Within the next 3 years:** PG&E will benchmark other utilities to identify other emerging technologies to enhance the inspection protocols.
4. **Within the next 10 years:** PG&E may develop asset or component-specific examination protocols that are proactively prescribed based upon predictive asset failure modelling.

5.3.4.11 Patrol Inspections of Distribution Electric Lines and Equipment

Patrol inspections of distribution electric lines and equipment are routinely undertaken for assets not scheduled for a detailed or climbing inspection within the calendar year. Patrol inspections are defined within the EDPM (TD-2301M) as maintenance activities that include a simple, visual examination of applicable overhead and underground facilities to identify obvious structural problems and hazards. Patrol inspections are visual reviews of the asset condition to proactively detect imminent or existing safety or reliability hazards in alignment with GO 165. Distribution overhead patrols may be executed on foot or by vehicle as appropriate to the terrain. See Section 5.3.4.1 for a description of PG&E’s detailed inspection program for distribution lines and equipment.

Progress Timeline

- 1. **Before the upcoming wildfire season:** Continue to implement the patrol inspection program. No enhancements are anticipated before the upcoming wildfire season.
- 2. **Before the next annual update:** PG&E intends to pilot paperless digital (mobile) patrol inspections protocols and records.
- 3. **Within the next 3 years:** PG&E intends to adopt paperless digital (mobile) patrol inspections technologies.
- 4. **Within the next 10 years:** PG&E will determine if adjusting asset patrol inspection cycles or modalities is likely to have adverse impacts on system safety or performance. PG&E anticipates moving to a risk-informed circuit-based inspection protocol that prescribes the timing for preventive maintenance activities aligned to multiple asset and environmental factors.

5.3.4.12 Patrol Inspections of Transmission Electric Lines and Equipment

Patrol inspections of transmission electric lines and equipment are performed in alignment with PG&E's approved CAISO Maintenance Plan. Patrol inspections of transmission electric lines and equipment are routinely undertaken for assets not scheduled for a detailed or climbing inspection within the same calendar year. Patrol inspections are defined within the ETPM (TD-1001M) as maintenance activities that include a simple, visual examination of applicable overhead and underground facilities to identify obvious structural problems and hazards. Patrol inspections may be undertaken by foot, vehicle, boat, or helicopter as appropriate to the terrain. See Section 5.3.4.2 for a description of PG&E's detailed inspection program for transmission lines and equipment.

Progress Timeline

- 1. **Before the upcoming wildfire season:** Continue to implement the patrol and inspection program. No enhancements are anticipated before the upcoming wildfire season.
- 2. **Before the next annual update:** PG&E intends to pilot paperless digital (mobile) patrol inspections protocols and records.
- 3. **Within the next 3 years:** PG&E intends to adopt paperless digital (mobile) patrol inspections technologies.
- 4. **Within the next 10 years:** PG&E will determine if adjusting asset patrol inspection cycles or modalities is likely to have adverse impacts on system safety or performance. PG&E anticipates moving to a risk-informed circuit-based inspection protocol that prescribes the timing for preventive maintenance activities aligned to multiple asset and environmental factors.

5.3.4.13 Pole Loading Assessment Program to Determine Safety Factor

Pole loading assessment program to determine safety factor is applicable to distribution and transmission wood pole structures systemwide and has been in place for more than a decade. During a pole's service life, pole loading calculations are performed when load is added to a pole, or if a suspected overload condition is observed during inspection (GAC tags). Pole loading calculations are performed in O-Calc software during design phase to ensure poles are sized correctly to satisfy General Order 95 requirements. Following Commission Decision 09-08-029, pole loading calculations for poles in service are now retained. In 2016 PG&E began using O-Calc as its platform for completing pole loading calculations, and in 2017 a centralized database to retain Pole loading calculations record information was deployed.

In 2019, the Pole Loading Infrastructure Assessment program was initiated to increase the presence of pole loading calculations with "desktop verified" or better status in the Pole Loading Database (PLDB) by 10% annually, as desktop verifications are completed. The program is in development and is scheduled to be fully implemented in T2 / T3 HFTD areas in 2024. T1 deployment is planned to follow T2/T3 areas. Desktop validation of 100% of poles in T2 / T3 HFTD Areas is scheduled by 2024. Baseline pole loading calculations, Models & Pole Characteristics, performed using EDGIS information (small class, multiple circuits, treatment) help identify the priority assets for desktop verifications. Estimating resources provide quality assurance check on desktop reviews performed by contractors.

Progress Timeline

1. **Before the upcoming wildfire season:** Continue conducting pole loading calculations with desktop verifications. No enhancements are anticipated before the upcoming wildfire season.
2. **Before the next annual update:** Continue conducting pole loading calculations and desktop verifications as described above.
3. **Within the next 3 years:** Continue conducting pole loading calculations and desktop verifications as described above. Desktop validation of 100 percent of the poles in Tier 2 and Tier 3 HFTD areas will be in process.
4. **Within the next 10 years:** Complete desktop validation of all poles in Tier 2 and Tier 3 HFTD areas in the system.

5.3.4.14 Quality Assurance / Quality Control of Inspections

Quality assurance/quality control of inspections utilizes a combination of program, process, tool, and other control points intended to rapidly identify anomalies in inspection and patrol results with the intention of addressing the gap, determining the root cause, and pursuing improvement opportunities. Among other things, quality assurance could mean establishing baseline metrics and measures of program performance to highlight outliers in any inspection process step. Quality controls can be established to identify inspection personnel who report abnormally high or low rates of corrective findings in the field. This could also mean identifying inspection personnel who experience abnormal rates of changes of their initial findings (increased or decreased priority of findings, rejection of findings).

PG&E's practice of a secondary review of all field inspection findings via a centralized gatekeeper prior to recording the finding in the system of record is one operational practice that works to drive consistency in inspection results. Work verification of inspector field inspection results by supervisory personnel, or through a representative re-inspection sampling scheme, is another means to assess the quality of inspection personnel. Work verification has been used for inspection quality management through 2019, yet PG&E will begin to leverage the data collected during digital paperless inspections and patrols to lessen the need for this type of after-the-fact sampling approach. In late 2019, PG&E issued guidance for self-assessment and enhancement of inspection program quality, which applies to electric asset inspection programs (GOV-1038S). In alignment with that guidance, PG&E will continue to self-assess process capabilities and improve maturity of inspection process quality management.

For inspections, quality assurance and quality control support are also provided after-the-fact by internal departments such as Internal Auditing (IA) and Electric Quality Management (EQM), who sample work to ensure it conforms to the governing process guidance. IA uses a risk-based approach in developing its annual Audit Plan. As part of this process, IA considers key and/or emerging risks that the Utility is facing, such as those related to the Utility's electric system that is exposed to wild fire hazards. IA includes audits covering these risks in its annual Plan; examples for 2020 include audits of inspection and maintenance processes for transmission and substation assets, and inspection and maintenance processes for distribution assets. In performing each individual audit, IA develops a risk and control matrix to document the relevant risks and controls and to help identify gaps and determine the scope of the audit. More specifically, in performing inspection and maintenance audits of electric assets, IA generally performs audit steps to assess the following:

- There is a complete population of electric assets for inspection,
- Utility and/or contract personnel performing the inspection and maintenance work are appropriately trained/qualified,
- Inspections and corrective work are completed within required timeframes,
- Work is performed to standard,
- Inspection and maintenance records are complete, accurate, and retrievable, and

- Inspection and maintenance guidance documents are current.

In performing this work, IA performs field visits (which may include consultation with Utility subject matter experts), interviews relevant Utility personnel, and reviews/tests applicable documentation. IA focuses on processes and controls. It does not have the technical expertise to evaluate the quality of corrective work; IA assesses the Utility's processes for ensuring that work is performed to quality, including evidence of review/approval by appropriate employees that the work adheres to Utility standards.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E will consolidate its inspection gatekeeping function for transmission, distribution, and substation.
2. **Before the next annual update:** PG&E will establish initial process quality control metrics for field data collectors, inspectors, and gatekeepers (reviewers).
3. **Within the next 3 years:** PG&E plans to move all electric patrol and inspection activities to digital data collection platforms (e.g., mobile applications) and away from paper record keeping. Concurrently, PG&E will develop process control measures to more rapidly assess for abnormalities in patrol and inspection findings.
4. **Within the next 10 years:** PG&E will continue to evolve and improve its QA/QC programs.

5.3.4.15 Substation Inspections

Substation GO 174 baseline inspections in Tier 2 and Tier 3 HFTD areas were supplemented in 2019 as part of WSIP. PG&E baseline substation preventive maintenance practices ensure compliance with requirements of various regulatory agencies such as the CAISO, NERC, WECC, CPUC. The 2019 WSIP substation inspection program was designed to identify issues with substation equipment and components that could lead to a potential ignition source for a wildfire event.

Building on WSIP 2019, to further minimize the risk of a substation equipment failure causing a public or employee safety or system reliability concern (e.g., spreading a fire outside of the substation), PG&E has developed an ongoing program for performing supplemental inspections on selected facilities, based on risk assessment. These supplemental inspections are performed in addition to the routine inspections that are part of the maintenance practices described in utility standards TD-3322S and TD-3323S. To develop this supplemental inspection program, failure modes and effects analysis was performed on all substation equipment. As for the other WSIP 2019, substation supplemental (enhanced) inspections will utilize a mobile electronic checklist aligned to the FMEA to guide field assessments.

The WSIP program (and ongoing) supplemental inspections were carried out by teams of personnel, used visual and infrared inspection techniques to validate the condition of specific equipment and components. The supplemental inspection program includes three methods: Drone-based aerial inspection, Ground-based visual inspection, and Infrared inspection. Going forward, the supplemental inspections will be performed in PG&E-owned substations based on the following risk factors: High Fire Threat Districts (HFTD), Transmission Substation criticality, and Distribution Substation customer count. In 2020, supplemental inspections once annually for all HFTD Tier 3 stations, on a three-year cycle for stations in HFTD Tier 2. Additional non-HFTD sites may also be assessed using these supplemental inspection methods. For 2020-22, the baseline GO 174 monthly (or bi-monthly) station inspections are anticipated to proceed as per existing protocols. For 2019 WSIP, internal process quality checks were completed by the Electric Transmission Quality Verification team. In 2020, quality checks will utilize similar control measures as the transmission and distribution programs, including the centralized inspection review team.

Progress Timeline

1. **Before the upcoming wildfire season:** No changes to supplemental inspections are anticipated.
2. **Before the next annual update:** PG&E will continue to implement its substation inspection program as described above and expects to implement a new inspection field mobile application.
3. **Within the next 3 years:** PG&E intends to merge routine monthly and enhanced/supplemental detailed inspections using risk informed criteria to drive condition-based maintenance cycles.
4. **Within the next 10 years:** PG&E will also determine if adjusting asset patrol inspection cycles or modalities is likely to have adverse impacts on system safety or performance. PG&E anticipates moving to a risk-informed circuit-based inspection protocol that prescribes the timing for preventive maintenance activities aligned to multiple asset and environmental factors.

5.3.5 Vegetation Management and Inspections

Explain the rationale for any utility ignition probability-specific inspections (e.g., "enhanced inspections") within the HFTD as deemed necessary over and above the standard inspections. This shall include information about how (i.e., criteria, protocols, etc.) the electrical corporation determines additional inspections are necessary.

Describe the utility's vegetation treatment protocols relating to treatment of any vegetation that could pose a grow-in or fall-in risk to utility equipment. Include in the description the threshold by which the utility makes decisions of whether to (1) treat, or (2) remove vegetation.

Discuss the overall objectives, strategies, and tactics of the electrical corporation for vegetation management. In the discussion,

1. Address how the electrical corporation has collaborated with local land managers to leverage opportunities for fuel treatment activities and fire break creation, and compliance with other local, state, and federal forestry and timber regulations.
2. Discuss how the electrical corporation identifies and determines which vegetation is at risk of ignition from utility electric lines and equipment.
3. Describe how (i.e., criteria, data, protocols, studies, etc.) the utility made the determination to trim any vegetation beyond required clearances in GO 95.
4. Describe utility plan to mitigate identified trees with strike potential, including information about how (i.e., criteria, protocols, data, statutes, etc.) the electrical corporation identifies and defines "hazard trees" and "trees with strike potential" based on height and feasible path to strike powerlines or equipment. Describe utility plan to identify reliability/at-risk tree species to trim or remove, where feasible, per location-specific criteria.
5. Include a discussion of how the utility's overall vegetation management initiatives address risks that may arise from trimming or removing trees, including but not limited to erosion, wind, flooding, etc.

Description of Programs to Reduce Ignition Probability and Wildfire Consequence

For each of the below initiatives, provide a detailed description and approximate timeline of each, whether already implemented or planned, to minimize the risk of its equipment or facilities causing wildfires. Include a description of the utility's initiatives, the utility's rationale behind each of the elements of the initiatives, the utility's prioritization approach/methodology to determine spending and deployment of human and other resources, how the utility will conduct audits or other quality checks on each initiative, how the utility plans to demonstrate over time whether each component of the initiatives is effective and, if not, how the utility plans to evolve each component to ensure effective spend of ratepayer funds.

Include descriptions across each of the following initiatives. Input the following initiative names into a spreadsheet formatted according to the template below and input information for each cell in the row.

1. Additional efforts to manage community and environmental impacts

- 2. Detailed inspections of vegetation around distribution electric lines and equipment
- 3. Detailed inspections of vegetation around transmission electric lines and equipment
- 4. Emergency response vegetation management due to red flag warning or other urgent conditions
- 5. Fuel management and reduction of "slash" from vegetation management activities
- 6. Improvement of inspections
- 7. LiDAR inspections of vegetation around distribution electric lines and equipment
- 8. LiDAR inspections of vegetation around transmission electric lines and equipment
- 9. Other discretionary inspection of vegetation around distribution electric lines and equipment, beyond inspections mandated by rules and regulations
- 10. Other discretionary inspection of vegetation around transmission electric lines and equipment, beyond inspections mandated by rules and regulations
- 11. Patrol inspections of vegetation around distribution electric lines and equipment
- 12. Patrol inspections of vegetation around transmission electric lines and equipment
- 13. Quality assurance / quality control of inspections
- 14. Recruiting and training of vegetation management personnel
- 15. Remediation of at-risk species
- 16. Removal and remediation of trees with strike potential to electric lines and equipment
- 17. Substation inspections
- 18. Substation vegetation management
- 19. Vegetation inventory system
- 20. Vegetation management to achieve clearances around electric lines and equipment
- 21. Other / not listed [only if an initiative cannot feasibly be classified within those listed above]

Overview of PG&E's Vegetation Management Program

Given the growing wildfire threat, PG&E has further expanded and enhanced its vegetation management around assets in HFTD areas. This includes addressing vegetation that poses a higher potential for wildfire risk in high fire-threat areas through PG&E's Enhanced Vegetation Management (EVM) program. The goal of this important wildfire safety effort is to reduce the risk of trees, limbs and branches contacting power lines and equipment to help keep our customers and communities safe.

This work is critical because PG&E operates in a heavily forested¹⁷ and vegetated area, particularly compared to the other large California utilities. Additionally, PG&E's service area includes approximately:

- 81,000 circuit miles of overhead distribution power lines with approximately 25,200 circuit miles in HFTD areas
- 18,000 circuit miles of overhead transmission power lines with approximately 5,520 miles in HFTD areas
- An estimated 120 million or more trees with the potential to grow or fall into overhead power lines

The EVM program is being done in addition to other baseline and long-standing, multi-pronged PG&E vegetation management programs with various elements all designed to:

- Proactively conduct tree work that reduces the likelihood of tree failure that could impact electric facilities and pose a public safety risk;
- Comply with State and Federal regulations regarding minimum vegetation clearances for the Electric Transmission & Distribution overhead systems;
- Perform annual inspections so required vegetation clearances are maintained, remain compliant year-round and hazardous trees are abated;
- Maintain vegetation-to-line clearances, and radial clearances around poles, pursuant to PRC Sections 4292 and 4293, GO 95 Rule 35, and FAC-003-4 (Federal Electric Transmission standard), to ensure year-round compliance and risk reduction; and
- Validate that work was done as planned and intended through Quality Control (QC) and Quality Assurance (QA) reviews; including maintaining auditable records of all work done.

PG&E's EVM program encompasses all overhead distribution lines in Tier 2 and Tier 3 HFTD areas and is designed to exceed its annual Routine Vegetation Management work to comply with CPUC mandated clearances (GO 95, Rule 35). In HFTD areas, PG&E's Routine Vegetation Management meets regulations requiring 4 feet radial clearance around overhead distribution lines. The EVM program is much more expansive and aggressive and includes the following:

- **Radial Clearances:** Exceeding the 4-foot minimum clearance requirement by ensuring vegetation is trimmed to the CPUC recommended 12-foot clearance at time of trim to maintain compliance year-round, and in some cases, trimming beyond 12 feet depending on tree growth rates, among other factors. Trimming to the CPUC recommended 12-foot clearance ensures compliance with GO 95, Rule 35 year-round.
- **Overhang Trimming:** Removing overhanging branches and limbs four feet out from the lines and up to the sky for particular trees around electric power lines ~~required by regulatory requirements~~ to further reduce the possibility of wildfire ignitions and/or downed wires and outages due to vegetation-conductor contact.

¹⁷ For representations of the density of forests in PG&E's service territory within California. See pp. 3, 6, 7, 17 and more of https://www.fs.fed.us/pnw/pubs/pnw_gtr913.pdf.

- **Assessing Trees with the Potential to Strike:** Evaluating all trees tall enough to strike electrical lines or equipment and, based on that assessment, trimming or removing trees that pose a potential safety risk, including dead and dying trees.

Objectives, Strategies, and Tactics for Vegetation Management

1. Collaboration with Local Land Managers and Regulation Compliance

In order to facilitate timely completion of VM activities, PG&E is and will continue to collaborate with local landowners and communities, local governments, state agencies and federal agencies. This includes coordinating with cities, counties and other local authorities to obtain local encroachment permits or to manage other local requirements. PG&E's VM activities comply with endangered species and fish and game restrictions, CAL FIRE forest practices rules and state permitting requirements that could trigger review under the California Environmental Quality Act (CEQA). PG&E's VM Program is focused to a large degree on compliance with GO 95 Rules 35 and 37, PRC 4292, and PRC 4293.

While VM is focused on complying with regulatory requirements, PG&E's higher mission is to perform VM in ways that reduce wildfire threat as circumstances dictate. Because climate threat conditions today are more severe than those that existed when regulations were developed and adopted, PG&E's views VM requirements as the minimum standards for reducing risk. The program includes inspection identification, clearing and removal of potentially problematic vegetation, as well as Quality Assurance (QA) review of that work. PG&E's EVM Overhang Clearing will support compliance with GO 95 Rule 35 and PRC 4293 that require that no vegetation approach within four feet of electric distribution wires at any time.

2. Identify and Determination of Ignition Risk

PG&E complies with D.14-02-105 in which the CPUC adopted a Fire Incident Data Collection Plan that requires IOUs to collect and annually report certain information related to fire-related events. PG&E's annual report includes: the number of fire incidents; number of incidents by fire size; suspected ignition cause (e.g., third-party contact, equipment/ facility failure, wire/wire contact, objects); object type suspected of causing ignition; and, equipment failure type suspected of causing ignition. In addition, PG&E provides additional information about the tree species suspected of causing ignition. The data contained in these reports is analyzed to identify and determine the causes of ignition risk which ultimately drives the development of wildfire mitigation programs.

3. Determination to Trim Beyond GO 95 Requirements

PG&E determined that in certain circumstances it was prudent to exceed the GO 95 requirements for tree trimming. For example, instead of the required four feet radial clearance around conductors, PG&E is trimming trees from the conductor to sky for overhang clearing on particular trees. Additionally, through its EVM program, PG&E removes or trims trees outside of the GO 95 prescribed four-foot clearance where trees more than four feet away from a power line are determined to be hazard trees and have a clear path to strike.

Deleted: such as heritage tree requirements

4. Mitigation of Hazard Trees

PG&E initially identified 10 high risk tree species for removal where they are tall enough to strike a power line, have a clear path to strike, and exhibit other potential risk factors. However, PG&E continues to evolve the hazard tree mitigation program as it gains experience and receives input from the CPUC, industry and stakeholders about its tree assessment, program design, quality assessment and decision-making process. PG&E and the other California utilities will conduct a study to assess the need for and scope of the targeted tree species program. Depending on the circumstances, trees that have died or become unstable may be removed under either Enhanced VM or the Tree Mortality Program. When PG&E determines that overhang clearing work is so extensive that it will kill a tree, this tree is removed as part of the EVM Program. If overhang clearing work will only potentially cause a tree to die, the tree can generally be trimmed and left in place, subject to the property owner's agreement, to see if it recovers. In the latter case, if PG&E determines in a subsequent vegetation management inspection that a tree left in place ultimately died, that tree will be removed under the Tree Mortality Program.

5. Overall Vegetation Management Initiatives

PG&E's VM and EVM initiatives are designed to address the overall VM objectives including:

- Enhance community and public safety by further reducing the risk of power outages, wires down, and fires caused by trees growing or falling into high voltage distribution lines;
- Maintain the reliability of the electric distribution system and continue to comply with vegetation clearance regulations through the Routine Tree Work and Vegetation Control programs;
- Maintain program and work quality through a QA program;
- Continue to educate the public about the hazards posed by high voltage lines and vegetation through Public Education outreach efforts;
- Further improve field working conditions and safety practices for tree works through the Contractor Safety program; and
- Continue to comply with environmental regulations while performing VM work.

The EVM initiatives that PG&E introduced in 2018 included:

- Overhang Clearing: Removing branches overhanging electric power lines to further reduce the possibility of wildfire ignitions and/or downed wires due to vegetation-conductor contact;
- Targeted Tree Species Work: Identifying and pruning or removing specific tree species adjacent to power lines that may have a higher potential to fail during wildfire season;

- Fuel Reduction: Reducing vegetative fuels in the area under and adjacent to power lines with the intention of further reducing wildfire risk;
- Light Detection and Ranging (LIDAR) Using analytics from LIDAR and imagery (collectively referred to as remote sensing) data collection to augment the information gathered through manual patrols.

PG&E continues to refine its VM and EVM programs based on additional data and experience, feedback from stakeholders and the Commission, and developments within the vegetation management industry.

Description of Programs

The tables below outline various initiatives within PG&E's EVM program and broader vegetation management initiatives. While these initiatives are generally focused on supporting compliance with minimum clearance requirements, they are not static and continue to be informed by the evolving wildfire risk.

See Attachment 1, Table 24 for the details and data associated with the initiatives discussed in this section.

5.3.5.1 Additional Efforts to Manage Community and Environmental Impacts

PG&E wants customers and communities to be completely informed about the EVM work taking place in their community. Vegetation management work in general, and the EVM work in particular, has an impact on the communities and properties where work is identified. PG&E proactively communicates to and partners with land owners, government agencies and community organizations on the work we are planning. In some cases, through PG&E's outreach regarding this work, opportunities also arise for communities or agencies to leverage the work PG&E is doing to support or enhance community specific plans or efforts. In addition, for the past several years PG&E has provided grant funding to community organizations (generally Fire Safe Councils) to support them in performing community wildfire risk mitigation efforts, like fuel break creation or fuel cleanup efforts, that may not be adjacent to PG&E powerlines and therefore outside of the scope of PG&E's vegetation management programs.

The performance of vegetation management work could create environmental impacts as well, which PG&E is careful to mitigate, monitor, and manage. PG&E vegetation management contractors are trained on Best Management Practices and Avoidance and Minimization Measures to help prevent impacts to sensitive environmental resources and protect waterways. For example, in some cases wood debris is re-distributed around the work area to create a mulch layer to cover the soil and prevent erosion. In addition, stumps and roots are left in place which can also help mitigate potential erosion issues.

Similarly, changing the ecosystem of a stand of trees can create new risks, like exposing a previously protected tree to increased sunlight or wind, that the utility arborists performing PG&E's vegetation management work are conscious of and on the lookout for. Trees that exhibit risk factors (like poor taper) and could be a risk after adjacent tree work is performed may be proactively identified for treatment (trimming or removal).

PG&E also coordinates with numerous cities, counties, and other local authorities to obtain local encroachment permits or to manage other local requirements. However, some state permitting requirements could cause delays by triggering review under the California Environmental Quality Act (CEQA). For example, PRC Section 30000 imposes requirements on tree removal in coastal zones. Not only is this requirement administered by many local governments through certified local coastal programs, requiring coordination for each area worked, if a permit is needed, but the level of CEQA review is determined separately by each permitting authority. Likewise, CAL FIRE forest practice rules also require approvals for the removal and disposal of trees. Vegetation management activities must also comply with endangered species and fish and game restrictions, which may trigger permitting requirements, as well as restrict when, where, or how the work may be performed (e.g., not during nesting season). Work on federal lands also require permits for tree removal, VM work, or land rights that predate federal ownership of the land.

Deleted: in and around their neighborhood

Deleted: to manage erosion, prevent impacts to sensitive environmental resources (e.g., bird nests, sensitive species and habitats) and protect waterways

Deleted: , such as heritage tree ordinances

PG&E's land and environmental management and customer care teams work closely with PG&E's vegetation management team to overcome challenges as described above and any other challenges that may come with this impactful work as quickly as possible. They coordinate and plan the work in order to reach out to landowners, communities, and local governments to address concerns in advance of the proposed vegetation management activities. PG&E tries to reach mutually agreeable results with concerned parties, but this regularly causes delays and sometimes PG&E must seek court orders. It could be helpful if the CPUC or state legislature addressed these constraints. For example, if the legislature extended PRC Section 4295.5 to also authorize utility tree workers to trim or remove trees or clarified the definition of a "conversion" in the forest practice rules to clearly exclude maintenance of a utility right of way, it could significantly improve the ability to execute vegetation management work. Likewise, legislative action could restrict the discretionary terms attached to encroachment permits.

In the coming years, PG&E will continue to communicate and partner with stakeholders regarding this important vegetation safety work. In addition, and where possible, PG&E will inform cities and counties of vegetation management work within their community and work with them to address any questions they may have.

Progress Timeline

- 1. Before the upcoming wildfire season:** As described above, PG&E will continue to: inform customers and communities about the vegetation management work taking place or planned to take place in their community through customer outreach efforts; monitor and manage potential environmental impacts resulting from EVM activities; obtain the necessary permits and clearances before conducting work; and reach out to local landowners, communities and local governments to address potential concerns about planned and ongoing EVM work.
- 2. Before the next annual update:** PG&E will continue to implement the activities described above before the next annual update. Additionally, PG&E will incorporate lessons learned in 2020 in its efforts to manage community and environmental impacts going forward.
- 3. Within the next 3 years:** PG&E will continue to implement the activities described above within the next three years. To the extent regulations, permitting requirements or legislative changes are implemented, PG&E will adjust its efforts to manage community and environmental impacts to address these changes.
- 4. Within the next 10 years:** PG&E will continue to implement the activities described above within the next ten years. To the extent regulations, permitting requirements or legislative changes are implemented, PG&E will adjust its efforts to manage community and environmental impacts to address these changes.

5.3.5.2 Detailed Inspections of Vegetation Around Distribution Electric Lines and Equipment

PG&E conducts detailed inspections of vegetation around distribution electric lines and equipment on an annual cycle under its routine VM program.

Pre-inspection is the first step in the vegetation management process. After onboarding inspectors as described in Section 5.3.5.14 below, pre-inspectors are assigned circuits and deployed to work in various areas throughout PG&E's service territory. Correctly assessing tree characteristics such as species, health, growth rate, and likely failure patterns is critical to determining the type of tree work needed to reduce wildfire risk and to keep trees from coming into contact with power lines or electrical equipment. Importantly, all trees identified for work by pre-inspectors are evaluated for the urgency of the required tree work. If tree failure is judged to be possibly imminent, a crew will be dispatched the same day. Trees can also be flagged for immediate follow-up work, while trees that require work but show no near-term risk factors are scheduled following the standard process.

Trees identified for work by the pre-inspector are then assigned to a tree crew to be worked according to PG&E standards to create adequate tree-to-line clearances.

PG&E assesses routine vegetation management work performance using both Quality Control (QC) and Quality Assurance (QA) processes. Both QC and QA process select samples to assess. QC samples inspections or tree work recently completed to validate that all work was performed in accordance with PG&E standards. The QA effort is designed to validate that the entire process, starting with pre-inspectors, is creating the desired outcomes and identify areas where expectations are not being met, and if additional work is needed or other process modifications are required.

QA is accomplished through the physical inspection of a sample of the newly cleared PG&E system. The objective of the sampling exercise is to estimate the work quality rate for all trees in the geographic area covered by an audit. PG&E uses the results of the QA Program to improve future performance and to also help inform performance management activities such as re-training of pre-inspectors. PG&E has reviewed its QA Program and procedures with third-party experts who have validated that the sampling design in use is appropriate for PG&E's objectives, stating "[t]he use of a cluster sampling design is entirely appropriate for PG&E's objectives...."¹⁸

¹⁸ Dr. Karl Snow of Bates White Economic Consulting, PG&E's QA statistical sampling methodology.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E will continue to execute its detailed inspection program around distribution lines and equipment as described above: PG&E will conduct a pre-inspection to assess tree characteristics and determine the urgency of the required tree work; pre-inspectors will prescribe the appropriate work by circuit to maintain adequate vegetation-to-line clearances. PG&E's tree contractors will conduct the prescribed tree work. PG&E will implement its QA program to assess the quality of work performed in the field.
2. **Before the next annual update:** PG&E will continue to execute its detailed inspection program and associated tree work as described above.
3. **Within the next 3 years:** PG&E will continue to implement the activities described above within the next three years and will continue to incorporate lessons learned as the program evolves. To the extent that regulations change or new regulations or requirements are adopted, PG&E will adjust its program to comply with those changes.
4. **Within the next 10 years:** PG&E will continue to implement the activities described above and will continue to incorporate lessons learned as the program evolves. To the extent that regulations change or new regulations or requirements are adopted, PG&E will adjust its program to comply with those changes.

5.3.5.3 Detailed Inspections of Vegetation Around Transmission Electric Lines and Equipment

PG&E’s transmission vegetation management work is regulated by the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC). PG&E is required to comply with the NERC Standard – FAC-003-4, which is a FERC-approved standard implemented to eliminate transmission outages and resulting blackouts due to vegetation contact. This standard applies to transmission lines carrying 200,000 volts and higher and certain lower-voltage transmission lines identified as critical by the WECC. It requires that PG&E patrol and clear any vegetation that is incompatible with the clearances set forth in the FAC-003-4 standard.

In addition, we also comply with the American National Standards Institute’s (ANSI) A300 – Part 7 Integrated Vegetation Management (IVM) Standard, followed by electric utilities nation-wide. IVM involves removing any vegetation that is incompatible with the safe and reliable operation and maintenance of high-voltage transmission lines. The standard also includes maintaining the Wire Zone and Border Zone surrounding the lines by establishing and maintaining a corridor that retains low fire risk, along with healthy and compatible vegetation, and removal of all incompatible vegetation.

The Wire Zone is the area under the transmission wires, plus 10 feet beyond the outside wires. The Border Zone extends from the Wire Zone out to the edge of the corridor, which may be up to 50 feet from the transmission centerline on 115 kV lines. Industry best practices dictate we remove incompatible vegetation up to and beyond the Border Zone due to various factors, including:

- Line sag and wind sway
- Vegetation treatment cycle length
- Tree movement and limbs blowing into the corridor in high-wind scenarios
- Line height above the ground and streams
- Sensitive species habitats

In addition, PG&E will remove or trim any hazard and/or danger trees beyond the Border Zone that could fall and strike the line. A danger tree is any tree located on or adjacent to a utility right-of-way or facility having characteristics with higher likelihood of failure that could damage utility facilities should it fall, as defined by Title 14 California Code of Regulations, Sec. 895.1. A hazard tree is a tree that poses an increased potential risk of falling into the lines due to, for example, poor health (all or a portion of the tree dying, diseased or decayed) or other defects.

In order to maintain these clearances, PG&E conducts annual inspections to remove any vegetation that is incompatible with the safety of high-voltage transmission lines and equipment.

In the coming years, PG&E will also be looking at the process and scope of work for overhang removals on all transmission circuits. Due to the historically broader

clearances maintained between transmission lines and vegetation and a practice of preventing direct overhangs of transmission lines, PG&E anticipates that the number of trees anticipated to require work to align the electric transmission system with this scope will be significantly less than for the distribution system.

Progress Timeline

1. **Before the upcoming wildfire season:** As described above, PG&E will continue to: conduct annual inspections to remove any vegetation that is incompatible with the safety of high-voltage transmission lines and equipment; maintain the Wire Zone and Border Zone surrounding transmission lines; and remove or trim any hazard and/or danger trees beyond the Border Zone that could fail and strike the line.
2. **Before the next annual update:** PG&E will continue to implement the activities described above before the next annual update. Additionally, PG&E will incorporate lessons learned in 2020 as part of its detailed transmission line and equipment inspection program going forward.
3. **Within the next 3 years:** PG&E will continue to implement the activities described above within the next three years. PG&E will also be looking at the process and scope of work for overhang removals on all transmission circuits. To the extent regulations or requirements related to the transmission inspection program change, PG&E will adjust its program to address those changes.
4. **Within the next 10 years:** PG&E will continue to implement the activities described above within the next ten years with adjustments as we determine that modifications are needed to better achieve the goal of reducing vegetation-to-line contacts that cause ignitions and potential wildfires. To the extent regulations or requirements related to the transmission inspection program change, PG&E will adjust its program to address those changes.

5.3.5.4 Emergency Response Vegetation Management Due to Red Flag Warning or Other Urgent Conditions

As described above in Section 5.3.5.2, all trees identified for work by pre-inspectors are evaluated for the urgency of the required tree work. If tree failure is judged to be possibly imminent, a crew will be dispatched the same day. Trees can also be flagged for **urgent** follow-up work, while trees that require work but show no near-term risk factors are scheduled following the standard process. The same process would be followed during any urgent conditions, as long as conditions are safe enough for the tree crews to work in.

Progress Timeline

- 1. **Before the upcoming wildfire season:** As described above, PG&E will continue to identify potentially imminent tree failure and flag trees for immediate follow-up work. PG&E will dispatch crews as soon as the same day an urgent condition is identified as long as crews can safely complete the work.
- 2. **Before the next annual update:** PG&E will continue to implement the activities described above before the next annual update. Additionally, PG&E will incorporate lessons learned in 2020 as part of its emergency response vegetation management program.
- 3. **Within the next 3 years:** PG&E will continue to implement the activities described above within the next three years.
- 4. **Within the next 10 years:** PG&E will continue to implement the activities described above within the next ten years subject to adjustments and evolution appropriate to technology opportunities, regulations and determination about the most effective ways to meet the goal of reducing vegetation-to-line contacts, ignitions and catastrophic wildfires.

Deleted: immediate

5.3.5.5 Fuel Management and Reduction of “Slash” From Vegetation Management Activities

In 2018, PG&E began a fuel reduction program, performing ground-to-conductor vegetative fuel reduction work (i.e. under and adjacent to power lines) in select locations. The goal of the fuel reduction work is to create “fire defense zones” which enhance defensible space for communities, properties, and buildings. These “fire defense zones” can also mitigate the spread of an ignition if one were to occur under or adjacent to PG&E powerlines. As such PG&E will continue to conduct fuel reduction work when appropriate, in select locations.

Progress Timeline

- 1. **Before the upcoming wildfire season:** As described above, PG&E will continue to conduct ground-to-conductor fuel reduction work, when and where appropriate.
- 2. **Before the next annual update:** PG&E will continue to implement the activities described above before the next annual update. Additionally, PG&E will incorporate lessons learned in 2020 as part of its fuel reduction program
- 3. **Within the next 3 years:** PG&E will continue to assess the effectiveness and risk reduction benefits of fuel reduction, and other vegetation management, activities to continue adjusting and refining vegetation management programs and the resource deployment across those programs.
- 4. **Within the next 10 years:** See above, PG&E will continue to assess the effectiveness and risk reduction benefits of fuel reduction activities to continue adjusting and refining the program.

5.3.5.6 Improvement of Inspections

See Section 5.3.5.2 (distribution inspections) and Section 5.3.5.3 (transmission inspections) above for a discussion of areas where PG&E's inspection programs are continuing to improve and mature.

5.3.5.7 LiDAR Inspections of Vegetation Around Distribution Electric Lines and Equipment

Physical, on the ground pre-inspections are being augmented by the capture of LiDAR and related, remote sensing, data that can be thoroughly and consistently analyzed to take measurements, reveal patterns and identify risks more precisely than the pre-inspector on the ground. In 2019, PG&E captured LiDAR for most Tier 2 and Tier 3 HFTD areas.¹⁹ In addition to LiDAR, PG&E also gathered hyperspectral data in 2019 and plans to use both to inform the accuracy of electric distribution lines in the ArcGIS layers used to identify power lines and identify trees with the potential to strike electric lines. PG&E will also continue to explore additional ways to utilize LiDAR data in the coming years. See also Section 5.3.4.7, LiDAR Inspections of Distribution Electric Lines and Equipment.

Progress Timeline

- 1. **Before the upcoming wildfire season:** As described above, PG&E will continue to use LiDAR and related, remote sensing data to reveal patterns and identify risk. PG&E will continue to correct the accuracy of electric distribution lines in its GIS data to more accurately identify trees with strike potential.
- 2. **Before the next annual update:** PG&E will continue to implement the activities described above before the next annual update. Additionally, PG&E will incorporate lessons learned in 2020 as part of its LiDAR program.
- 3. **Within the next 3 years:** PG&E will continue to implement the activities described above within the next three years. PG&E will continue to explore ways to use LiDAR data to reduce wildfire risk.
- 4. **Within the next 10 years:** PG&E will continue to implement the LiDAR program activities described above within the next ten years.

¹⁹ To underscore the unprecedented scope of this work, PG&E's 2019 data capture of approximately 25,200 distribution circuit miles is believed to be the world's largest ever hyperspectral data survey.

5.3.5.8 LIDAR Inspections of Vegetation Around Transmission Electric Lines and Equipment

Transmission LIDAR inspections are conducted every year as part of the transmission vegetation management program's annual inspections to identify necessary vegetation work. Any vegetation that requires work as identified by the LIDAR data analysis is then field verified by qualified pre-inspectors to prescribe the appropriate tree work. This also includes hazard trees that are encroaching into the right-of-way and trees that are tall enough to strike PG&E facilities, which are then further inspected on the ground.

Transmission LIDAR inspections are designed to identify work prior to any vegetation coming out of compliance and to align with PG&E's standards that exceed compliance clearances.

Progress Timeline

- 1. **Before the upcoming wildfire season:** As described above, PG&E will continue to use LIDAR to help identify vegetation management work along electric transmission lines. In addition, PG&E is developing a risk matrix using topographical and wind analysis to differentiate tree risk in HFTD areas from non-high fire-threat areas.
- 2. **Before the next annual update:** PG&E will continue to implement the activities described above before the next annual update.
- 3. **Within the next 3 years:** PG&E will continue to implement the activities described above as well as explore additional ways to reduce wildfire risk on transmission lines in the next three years. This may include developing applications in LIDAR and other remote sensing technologies to asses fuel loading in the right-of-way, among other potential initiatives.
- 4. **Within the next 10 years:** PG&E will continue to implement the LIDAR program activities described above within the next ten years.

5.3.5.9 Other Discretionary Inspection of Vegetation Around Distribution Electric Lines and Equipment, Beyond Inspections Mandated by Rules and Regulations

Following the guidance of tree mortality proclamations from California government officials and the CPUC in, and subsequent to, 2014 PG&E has undertaken additional inspections around overhead electric distribution lines to inspect for and remove dead or dying trees that threaten powerlines. Primarily this effort, referred to as the CEMA²⁰ program or "dead and dying tree program", involves performing a second annual inspection in many parts of our service territory, namely HFTDs and State Responsibility Areas (SRA), that are at higher risk of tree mortality and/or wildfire risk. ~~Further, in Wildland-Urban Interface (WUI) inspections are performed as frequently as quarterly, so 3 additional inspections in a year on top of the routine program's once annual inspection.~~

As these CEMA / "dead and dying" inspections result in identification of trees that need to be addressed they are assigned to a tree crew and removed. ~~PG&E will also inspect for and remove incidental vegetation that restricts access for safe and efficient removal of dead and dying trees may also be removed.~~

Progress Timeline

- 1. **Before the upcoming wildfire season:** As described above, PG&E will continue to execute additional annual inspections in HFTD and SRA areas and prioritize and work the trees identified for removal due to being dead or dying.
- 2. **Before the next annual update:** See above.
- 3. **Within the next 3 years:** PG&E anticipates continuing to execute the addition inspections of the CEMA program. Additionally, PG&E will incorporate lessons learned, further analysis and available data into optimizing the CEMA, and all other vegetation management, programs to reduce the likelihood of vegetation-to-line contacts and the associated wildfire risk.
- 4. **Within the next 10 years:** See above.

²⁰ The CEMA name simply refers to the memorandum account that the costs of this effort are recorded to: the Catastrophic Emergency Memorandum Account.

5.3.5.10 Other Discretionary Inspection of Vegetation Around Transmission Electric Lines and Equipment, Beyond Inspections Mandated by Rules and Regulations

See Section 5.3.5.3 (transmission inspections) above for a discussion of PG&E's vegetation inspection programs for transmission facilities. There are limited "other discretionary inspections" performed on Transmission lines.

5.3.5.11 Patrol Inspections of Vegetation Around Distribution Electric Lines and Equipment

See Section 5.3.5.2 (distribution inspections) above for a discussion of PG&E's vegetation inspection programs for distribution facilities. There is no specific program to perform "patrols" around distribution lines unique from the inspections described in Section 5.3.5.2.

5.3.5.12 Patrol Inspections of Vegetation Around Transmission Electric Lines and Equipment

See Section 5.3.5.3 (transmission inspections) above for a discussion of PG&E's vegetation inspection programs for transmission facilities. There is no specific program to perform "patrols" around transmission lines unique from the inspections described in Section 5.3.5.3.

5.3.5.13 Quality Assurance / Quality Control of Inspections

PG&E assesses vegetation management work performance using both Quality Control (QC) and Quality Assurance (QA) processes. Both QC and QA process select samples to assess. QC samples inspections or tree work recently completed to validate that all work was performed in accordance with PG&E standards. The QA effort is designed to validate that the entire process, starting with pre inspectors, is creating the desired outcomes and identify areas where expectations are not being met, and if additional work is needed or other process modifications are required.

QA is accomplished through the physical inspection of a sample of the newly cleared PG&E system. The objective of the sampling exercise is to estimate the work quality rate for all trees in the geographic area covered by an audit. PG&E uses the results of the QA Program to improve future performance and to also help inform performance management activities such as re-training of pre-inspectors. PG&E has reviewed its QA Program and procedures with third-party experts who have validated that the sampling design in use is appropriate for PG&E's objectives, stating "[t]he use of a cluster sampling design is entirely appropriate for PG&E's objectives...."

The one exception to the sampling discussed above is the EVM program where 100% of work completed is thoroughly reviewed through a work verification effort wherein all miles reported as completed by the assigned tree crew are then re-inspected to be validated as properly completed to EVM standards. If any trees were not managed to program scope then rework is assigned for completion before work verification is completed. On top of that 100% work verification process the EVM program is then also assessed with a sample-based QA program (as described in Section 5.3.5.15 below).

Note that the costs and program details provided in Section 13 of Table 25 combine the QC & QA efforts of the multiple vegetation management programs.

Progress Timeline

- 1. **Before the upcoming wildfire season:** As described above, PG&E will continue to deploy QC and QA programs to assess the performance of vegetation management activities and identify improvements or lessons learned.
- 2. **Before the next annual update:** As described above, PG&E will continue to deploy QC and QA programs to assess the performance of vegetation management activities and identify improvements or lessons learned.
- 3. **Within the next 3 years:** As described above, PG&E will continue to deploy QC and QA programs to assess the performance of vegetation management activities and identify improvements or lessons learned.
- 4. **Within the next 10 years:** As described above, PG&E will continue to deploy QC and QA programs to assess the performance of vegetation management activities and identify improvements or lessons learned.

5.3.5.14 Recruiting and Training of Vegetation Management Personnel

In 2019 alone, PG&E was able to increase its total contract pre-inspector workforce from 580 to 1375 pre-inspectors to meet the demands of the expansive EVM program. The pre-inspectors performing EVM work receive training from PG&E to teach contractors program scope, tools and relevant procedures to ensure consistency in how the work should be performed and how findings/prescriptions should be recorded. This process includes training and skills assessment testing. All pre-inspectors are required to take a skills assessment to show their competency on the program requirements and appropriate processes to gain and maintain access to PG&E EVM tools. The test comprises multiple choice questions about EVM's scope (e.g., the overhang and radial clearance requirements), to assess pre-inspectors' preparedness to accurately identify the work that should be prescribed in the field.

PG&E's intensive EVM program creates substantial challenges in regard to the availability qualified tree crew contractors. Previously, the most significant challenge to the EVM program schedule has been the limited availability of qualified workers, putting a strain on the timing and pacing of work. However, in 2019, PG&E was able to expand its contracted tree trimmer workforce from 1400 to 5437 new experienced tree workers and continues to identify additional tree crew contractors to complete this important work. By the end of 2019, 774 pre-inspectors and 2,234 tree trimmers were performing EVM work for PG&E.

The limited pool of qualified personnel, whether through contract, company or mutual aid, is exacerbated by the particular challenges of performing vegetation management work in Northern California. Logging and tree felling are one of the most hazardous industries in the nation, and the Northern California forests pose a very different challenge than in most parts of the country. Safely removing a 200+ foot tall tree in proximity of a high voltage distribution line must be done by a qualified professional.

The pace and schedule of PG&E's multi-year EVM program is based on maintaining a resource complement of approximately 3,000 qualified tree workers to perform vegetation management activities. With that volume of workers split between PG&E's routine VM and EVM programs results in an approximately 10-year EVM program until approximately 2028. Any acceleration of that schedule would require a sustainable increase in the volume of trained, safe, qualified, line clearance certified tree workers.

To address this constraint in the coming years, PG&E is exploring approaches to increase the population of qualified tree workers that could perform this work. PG&E is exploring possible partnerships with community colleges to develop VM pre-inspector and utility-qualified tree trimmer certificate programs to increase the talent pipeline. PG&E also expects Senate Bill 247 to increase the number of qualified tree workers in California over time, although however it will increase program costs due to increased wage requirements as per the senate bill. In addition, PG&E has also developed a series of trainings for transitioning pre-inspectors to move them from routine VM to EVM, to expand the available pool of contractor resources which can perform EVM work.

Progress Timeline

1. **Before the upcoming wildfire season:** As described above, PG&E will continue to: on-board qualified pre-inspectors; identify and hire qualified tree workers; confirm that pre-inspectors and tree workers are properly trained and qualified.
2. **Before the next annual update:** PG&E will continue to implement the activities described above before the next annual update. PG&E will continue to explore approaches to increase the population of qualified tree workers that can perform EVM work. Additionally, PG&E will incorporate lessons learned in 2020 into its approach for identifying, training and hiring qualified vegetation management personnel.
3. **Within the next 3 years:** PG&E will continue to implement the activities described above within the next three years. To the extent legislative changes occur that impact PG&E's approach for identifying, training and hiring vegetation management personnel, PG&E will adjust its program to address those changes.
4. **Within the next 10 years:** PG&E will continue to implement its vegetation management training and hiring program activities described above within the next ten years.

5.3.5.15 Remediation of At-Risk Species

PG&E's VM team conducts site visits to vegetation-caused outage events as part of its standard service interruption investigation process. The data collected from these investigations informs failure patterns by specific tree species associated with wire-down events. In 2018 PG&E used this data to target 10 species of trees that were responsible for nearly 75 percent of the investigated vegetation-caused outage events in HFTD. This data and list of "at-risk" tree species formed the basis of the EVM program.

The EVM program, further described in the introduction to this Section 5.3.5, also includes two additional aspects. However, the program is managed and executed in an integrated manner that prevents costs or activities from easily being separated into the components of the program. The two other aspects of the EVM program are (1) that all branches and limbs will be trimmed to the CPUC recommended 12-foot clearance at the time of trim (GO 95, Rule 35, Appendix E), and in some cases, trimming beyond the 12 feet depending on tree growth rates, among other factors; to remain compliant year-round; and (2) trimming and removal of overhanging vegetation from directly above and around distribution lines to supplement radial clearances. This work is focused on further limiting the possibility of wildfire ignitions and/or downed wires due to vegetation-conductor contact by removing branches and limbs that are overhanging within 4 feet of the conductors and up to the sky.

In response to the CPUC's direction in the 2019 WMP Decision, PG&E began evaluating all trees with the potential to strike or fall into power lines, above and beyond the original top 10 species of at-risk trees. With this enhanced effort to reduce wildfire risk, the total number of trees PG&E will evaluate as part of the EVM program has increased substantially to include the estimated 120 million or more trees in northern and central California that have the potential to grow or fall into overhead power lines. Pre-inspectors are identifying these trees using PG&E's tree assessment tool which is designed to evaluate a tree's risk of striking the electrical equipment. The tool was developed by a team of ISA Certified Utility Arborists and uses PG&E data regarding regional vegetation-caused outages and ignitions during fire season, tree species height and distance to the electrical equipment, lean, health, and the terrain, and among other factors. PG&E will continue assessing strike-potential trees in the coming years as part of the EVM program.

For EVM, pre-inspectors are responsible for walking the lines to look for radial clearances and overhanging branches and limbs, as described above. In addition, pre-inspectors are assessing trees around the power lines that are tall enough to strike the lines. Pre-inspectors will then prescribe the appropriate work to meet the EVM scope requirements. This prescribed tree work is then assigned to a Tree Crew to perform the work in a safe, compliant, efficient manner.

After all EVM-required tree work is completed by PG&E's contractors and passed 100% Work Verification (including the performance of an necessary rework before it is "passed" by the Work Verification assessor), the final step in the vegetation management process is the QA Program to assess the quality of work performed in the field. The QA effort is designed to validate that the entire process, starting with pre-inspectors, is creating the desired outcomes and identify areas where expectations

are not being met, and if additional work is needed or other process modifications are required.

The scale, scope and complexity of this work necessitates that, to address the more than 25,000 overhead distribution circuit miles in HFTD areas, this program is established as a multi-year effort. In 2019, the EVM program completed approximately 2,498 circuit miles which includes the vegetation clearances, overhang and hazard tree removals mentioned above. In 2020, PG&E plans to work approximately 1,800 additional circuit miles on both distribution lines in HFTDs, dependent on factors such as resource availability, vegetation density, topography, access and environmental considerations. As PG&E addresses the challenges that come with implementing an evolving and expansive program, the miles to be worked under the EVM program will continue to be re-assessed on a year-by-year basis. At this time, for 2021 and 2022, PG&E is forecasting to work on approximately 1,800 circuit miles each year.

~~In addition to establishing "new" miles that have been treated with EVM, PG&E will perform annual follow-up vegetation maintenance work on the sections of line where EVM was previously established to remove overhangs and to keep branches above powerline height from growing back into an overhanging position. As the number of miles initially worked to remove overhangs increases, the annual maintenance and upkeep effort will also grow along with the continued removal of hazard trees as outlined above.~~

Progress Timeline

1. **Before the upcoming wildfire season:** As described above, PG&E will continue to execute the EVM program and enhance its efforts to evaluate all trees with the potential to strike or fall onto power lines or electrical equipment.
2. **Before the next annual update:** PG&E will continue to implement the activities described above before the next annual update. PG&E, along with the other California utilities, will begin the process to study and assess the need for and scope of the targeted tree species program. Additionally, PG&E will incorporate lessons learned in 2020 into its EVM program and approach to remediating at-risk species.
3. **Within the next 3 years:** PG&E will continue to implement the activities described above; when the targeted tree species study is complete, PG&E will adjust its program to incorporate the findings from that study. PG&E will also continue to evaluate the interplay between EVM, PSPS and opportunities to perform additional wildfire risk mitigation work and will adjust the program, as appropriate, to maximize the benefits of PSPS, EVM and other mitigation programs.
4. **Within the next 10 years:** PG&E anticipates continuing to implement its EVM program with the focus on remediating at-risk tree species, incorporating the findings from the targeted tree species study and other lessons learned. PG&E will also continue to evaluate the interplay between EVM, PSPS and opportunities to perform additional wildfire risk mitigation work and will adjust the program, as appropriate, to maximize the benefits of PSPS, EVM and other mitigation programs.

5.3.5.16 Removal and Remediation of Trees with Strike Potential to Electric Lines and Equipment

Note that this broad initiative description overlaps with several of the previously discussed programs. Pursuant to PRC Section 4293 and GO 95, Rule 35, all PG&E vegetation management inspections assess for hazard trees. A hazard tree is defined as a tree that has been assessed from the ground to pose a potential danger to fall or fail into electrical facilities due to poor health (all or a portion of the tree dying, diseased or decayed) or other defects. See the previously outlined sections for more discussion of those routine activities to assess for hazard trees.

An additional program PG&E leverages to remove or remediate trees with strike potential is the Right of Way clearing program on the electric transmission system. This program seeks to create increased clearances, beyond compliance minimums, to further reduce wildfire risk and improve system reliability. This Right of Way expansion program seeks to create broader clearances on lower voltage transmission lines (60/70kV or 115kV) similar to the Wire Zone and Border Zone concepts applied to higher voltage lines (and discussed in Section 5.3.5.3). This work includes establishing and maintaining a corridor that retains low fire risk, along with healthy and compatible vegetation, and removal of all incompatible vegetation.

In addition to the wildfire risk reduction of establishing these cleared transmission rights of way PG&E is assessing how these activities can help reduce the scope and footprint of PSPS events. As discussed previously, having to shut off a transmission line during a PSPS event has major consequences for communities and customers. Service to all customers who are directly served by a single, long, radial transmission line will be shut off for the duration of the PSPS event, even though they may not be experiencing the same high-risk weather conditions.

By creating significantly increased clearances from vegetation to powerlines this transmission right of way clearing program is expected to raise the wind threshold for when a PSPS must be taken on lines where the cleared right of way has been established. To capture this double benefit of reduced wildfire risk and reduced PSPS footprint PG&E is increasing the focus on this work in 2020 by shifting some resources from EVM work on distribution lines to this right of way clearing work.

Progress Timeline

1. **Before the upcoming wildfire season:** As described above, continue executing transmission right of way clearing projects to reduce wildfire risk while completing analysis to determine the extent to which PSPS thresholds for treated transmission line segments can be modified to reduce the risk of PSPS outages for customers.
2. **Before the next annual update:** PG&E will continue to implement program activities and incorporate lessons learned in 2020.
3. **Within the next 3 years:** PG&E will continue to implement the activities described above and further incorporate lessons learned, updated risk analysis, and other insights to optimize this, and other, vegetation management program.
4. **Within the next 10 years:** PG&E will continue to implement the activities described above and further incorporate lessons learned, updated risk analysis, and other insights to optimize this, and other, vegetation management program.

5.3.5.17 Substation Inspections

PG&E is assessing the area around the substations in HFTD areas to ensure there is a safe distance between trees and/or vegetation and critical infrastructure to create defensible space. PG&E is looking at the area within 100 feet of the substation and potentially removing or thinning out trees and brush, per CAL FIRE recommendations and state guidelines. In 2019, PG&E conducted inspections of vegetation surrounding 222 substations and 70 hydro facilities in and around HFTD areas. In 2020, PG&E will continue to conduct annual maintenance of the defensible space around these facilities.

Progress Timeline

1. **Before the upcoming wildfire season:** As described above, PG&E will continue to inspect the areas around substations and critical infrastructure in HFTD areas to create defensible space and will conduct annual maintenance of the defensible space around these facilities.
2. **Before the next annual update:** PG&E will continue to implement the activities described above before the next annual update. Additionally, PG&E will incorporate lessons learned in 2020 into its substation inspection program.
3. **Within the next 3 years:** PG&E will continue to implement the activities described above within the next three years. To the extent regulations, guidelines or recommendations related to substation inspections change, PG&E will adjust its program to address those changes.
4. **Within the next 10 years:** PG&E will continue to implement its substation inspection program with modifications and improvements as appropriate, within the next ten years.

5.3.5.18 Substation Vegetation Management

Substation vegetation management efforts are incorporated into and addressed by the substation inspection program described in Section 5.3.5.17.

5.3.5.19 Vegetation Inventory System

PG&E’s vegetation management work is kept in a centralized system that includes the historical work prescribed and the timing of any tree work or inspections completed, among other things. PG&E’s EVM program also utilizes an ArcGIS application to manage work flows. In the coming years, PG&E will continue to review its processes and procedures and look for opportunities to enhance and streamline our vegetation inventory systems. Within the next few years, PG&E will continue to improve our tools. [Note that the costs for maintaining these tools and databases are included in the overall programmatic costs of executing vegetation management activities, principally Section 5.3.5.2 for distribution and Section 5.3.5.3 for transmission.]

Progress Timeline

- 1. **Before the upcoming wildfire season:** As described above, PG&E will continue to update and maintain its vegetation management inventory system.
- 2. **Before the next annual update:** PG&E will continue to update and maintain its vegetation management inventory system. Additionally, PG&E will incorporate lessons learned in 2020 into vegetation inventory program.
- 3. **Within the next 3 years:** PG&E will continue to implement the activities described above within the next three years. PG&E will identify opportunities to improve the systems and tools its uses to maintain its vegetation management records.
- 4. **Within the next 10 years:** PG&E will continue to implement its vegetation inventory program with modifications and improvements within the next ten years.

5.3.5.20 Vegetation Management to Achieve Clearances Around Electric Lines and Equipment

Vegetation management, i.e., tree trimming, to achieve clearances around electric lines and equipment is conducted as part of the routine and enhanced VM programs described in throughout the sections above. While possible in some instances PG&E generally does not separate the cost of inspections from the cost of the tree trimming or removal efforts. See Section 5.3.5.2 for the primary distribution efforts related to “achieving clearances” and Section 5.3.5.3 for transmission efforts on that front.

5.3.6 Grid Operations and Protocols

Description of Programs to Reduce Ignition Probability and Wildfire Consequence

For each of the below initiatives, provide a detailed description and approximate timeline of each, whether already implemented or planned, to minimize the risk of its equipment or facilities causing wildfires. Include a description of the utility's initiatives, the utility's rationale behind each of the elements of the initiatives, the utility's prioritization approach/methodology to determine spending and deployment of human and other resources, how the utility will conduct audits or other quality checks on each initiative, how the utility plans to demonstrate over time whether each component of the initiatives is effective and, if not, how the utility plans to evolve each component to ensure effective spend of ratepayer funds.

Include descriptions across each of the following initiatives. Input the following initiative names into a spreadsheet formatted according to the template below and input information for each cell in the row.

- 1. Automatic recloser operations
- 2. Crew-accompanying ignition prevention and suppression resources and services
- 3. Personnel work procedures and training in conditions of elevated fire risk
- 4. Protocols for PSPS re-energization
- 5. PSPS events and mitigation of PSPS impacts
- 6. Stationed and on-call ignition prevention and suppression resources and services
- 7. Other / not listed [only if an initiative cannot feasibly be classified within those listed above]

For each of the above initiatives, describe the utility's current program and provide an explanation of how the utility expects to evolve the utility's program over each of the following time periods:

- 1. Before the upcoming wildfire season,
- 2. Before the next annual update,
- 3. Within the next 3 years, and
- 4. Within the next 10 years.

See Attachment 1, Table 26 for the details and data associated with the initiatives discussed in this section.

5.3.6.1 Automatic Recloser Operations

PG&E utility Procedure TD-1464P-01 establishes precautions for wildfire risks associated with recloser protection functions. Reclosing devices such as circuit breakers and line reclosers are used to quickly and safely de-energize lines when a problem is detected and re-energize lines when the problem is cleared. Using analyses provided by fire officials and PG&E's Meteorology team regarding each year's fire season timeline and exposure, PG&E makes an informed decision on when to disable automatic reclosing/testing during elevated fire conditions in protection zones that intersect Tier 2 or Tier 3 HFTD zones. Timing for disabling/enabling is based on the condition of fuels and a recommendation made by the WSOC and Meteorology. Once the decision to disable has been approved by the Vice President of Asset Management, CWSP all reclosing devices for transmission 115kV and below and all distribution lines will be disabled during the determined utility fire risk season for protection zones that intersect Tier 2 or Tier 3 HFTD areas. In some instances, this practice may reduce potential ignitions from sustained faults.

There are approximately 2,800 distribution reclosing devices on PG&E lines serving Tier 2 and Tier 3 HFTD areas. The devices that have reclosing functionality include substation circuit breakers, line reclosers, FuseSavers, and TripSavers. By June of 2019, approximately 2,500 of the 2,800 reclosing devices serving Tier 2 and Tier 3 HFTD areas were SCADA-enabled. Most of the remaining non-SCADA devices are TripSavers which cannot be SCADA-enabled. By June 2020, PG&E will permanently remove the automatic reclosing functionality of the remaining TripSavers serving the Tier 2 and Tier 3 HFTD areas. This will result in less than 40 remaining non-SCADA distribution reclosing devices serving the Tier 2 and Tier 3 HFTD areas, and PG&E will manually disable automatic reclosing/testing during the determined utility fire risk season. In addition, reclosing devices located on nearly 400 transmission lines with voltages of 115 kV and below are included in the program. Over 95 percent of the transmission line devices are SCADA-enabled and can be disabled remotely, and like the distribution devices that are not SCADA-enabled, PG&E will manually disable the remaining devices during the determined utility fire risk season for protection zones that intersect Tier 2 or Tier 3 HFTD areas.

Existing distribution line reclosers that are operated for fire safety (e.g., as part of the PSPS or Recloser Disabling programs) were originally installed to optimize electric reliability and limit the number of customers exposed to outages, which can also present serious public safety concerns. These reclosers are often not optimally positioned to isolate the newly designated HFTD areas.

PG&E will continue upgrading devices with SCADA capability in targeted portions of the HFTD areas to help minimize the impact of PSPS events on customers in low-risk areas adjacent to the HFTD areas. These upgrades will include adding or replacing existing manually operated fuses and switches at strategic locations with new SCADA-enabled Fusesavers™, switches, or reclosers. By isolating the lines closer to the border of the HFTD, fewer customers will be impacted and fewer lines will be de-energized. These

improvements will also expedite restoration by reducing the amount of lines requiring a patrol.

PG&E discusses efforts to further sectionalize distribution circuits and limit the duration and number of customers impacted by PSPS events in Section 5.3.3.9, Installation of System Automation Equipment.

Progress Timeline

1. **Before the upcoming wildfire season:** Continue automatic recloser operations as described above.
2. **Before the next annual update:** Incorporate new reclosing devices that will be installed for the PSPS program into the reclose disable program.
3. **Within the next 3 years:** Continue to implement the reclose disable program as described above. Additionally, PG&E will begin to develop tools and technology to implementing the program using its Advance Distribution Management System (ADMS) that which would allow PG&E to disable/enable on a daily basis using fully automated computer systems.
4. **Within the next 10 years:** Implement the reclose disable program using the ADMS protocol described above.

5.3.6.2 Crew-Accompanying Ignition Prevention and Suppression Resources and Services

Safety and Infrastructure Protection Team (SIPT)²¹

The in-house SIPT team consists of two-person crews composed of IBEW-represented employees who are trained and certified safety infrastructure protection personnel. SIPT crews perform fire mitigation functions and gather critical data to help PG&E prepare for and manage wildfire risk. During elevated fire risk conditions, SIPT crews accompany PG&E crews when performing high risk work activities. In addition, SIPT crews perform critical fuel reduction work around PG&E assets to prevent damage from wildfires.

SIPT crews are expected to be utilized for the highest priority fire mitigation work.

Risk Informed Deployment of SIPT Crews

Prior to the next annual update, the WSOC intends to utilize various data points to calculate risk to inform SIPT deployment purposes. The WSOC plans to leverage a fire spread modeling application to support prioritization decisions. Factors will include fuel data, ignition potential calculations, weather forecasts, geography (terrain, slope, aspect, vegetation, etc.), historical climatology, and PG&E asset information.

Progress Timeline

- 1. *Before the upcoming wildfire season:* Update and stabilize the current technology solutions and processes and increase staffing levels to support fire prevention and mitigation activities. Targeted staffing levels and associated equipment needs: 98 SIPT Crew members and 40 Engineers.
- 2. *Before the next annual update:* Develop and implement risk informed prioritization model.
- 3. *Within the next 3 years:* Continue to assess effectiveness of program and develop risk informed business case to potentially increase staffing levels and equipment needs.
- 4. *Within the next 10 years:* Continue to evaluate the SIPT program and update and modify it as appropriate to address current wildfire mitigation efforts.

²¹ SIPT resources are also discussed in in Sections 5.3.2.5 and 5.3.6.6.

5.3.6.3 Personnel Work Procedures and Training in Conditions of Elevated Fire Risk

Update to Utility Standard TD-1464S, Preventing and Mitigating Fires While Performing PG&E Work

This standard establishes requirements for PG&E employees and contractors to follow when traveling over, performing work on, or operating on any forest, brush, or grass-covered lands. In 2019 the standard was updated to better reflect California Public Resource Code (PRC) Sections 4427, 4428, and 4430 and lay out specific mitigations and restrictions based on the work being performed and the daily fire danger. In addition to the standard, two attachments were also posted; a Wildfire Mitigation Matrix which reviews various types of daily work performed by PG&E employees and contractors along with required preventative measures that must be taken based on the daily fire danger and a Wildfire Mitigation Checklist which is a tool for crews to use prior to beginning work to ensure all the preventative measures within the matrix and standard are in place. A version of the TD-1464S Standard was also created and posted to the external website.

The revisions to the new standard were thoroughly reviewed within PG&E Over the course of 3 months there were many field meetings and virtual learning sessions with employee to communicate the PRC requirements and the standard updates. Meeting attendees also had opportunities to ask questions and provide input. In addition, a web-based, annual required training (SAFE-1503WBT) for PG&E employees was revised in 2019 to reflect the changes in the standard. The training objectives include: subscribing to and understanding PG&E's Utility Fire Potential Index, understanding TD-1464S and the aforementioned attachments and safe use of the required hand tools (i.e. Shovel, McLeod, Pulaski and a 5-gallon backpack pump). Required tools and equipment were also prescribed in the updated standard. A template was utilized by each impacted organization to identify and purchase the required tools and equipment for their respective organization.

In 2019 and 2020, the Wildfire Safety Operations Team plans to implement a safety observation card via SafetyNet (PG&E's Safety Observation Program) and Quality Control program to ensure that the updated fire prevention and mitigation measures have been adopted by personnel working and functioning on any forest, brush or grass-covered lands.

Progress Timeline

- 1. **Before the upcoming wildfire season:** Incorporate the fire prevention and mitigation checklist into SafetyNet.
- 2. **Before the next annual update:** Develop a Quality Control program to assess PG&E employee and contractor fire prevention and mitigation readiness.
- 3. **Within the next 3 years:** Continue to evaluate tools, equipment and other fire prevention and mitigation techniques to ensure field employees have the necessary training and resources while performing work in elevated fire risk areas.
- 4. **Within the next 10 years:** Continue to evaluate work procedures and training programs and update and modify them as appropriate to address current wildfire mitigation efforts.

5.3.6.4 Protocols for PSPS Re-Energization

The objective for PSPS re-energization is to provide for the safe, efficient restoration of PG&E electric facilities (Transmission Lines, Substations and Distribution Circuits), including prioritizing of critical infrastructure, after those facilities have been de-energized in the interest of public safety through a PSPS.

The PG&E EOC Officer in Charge triggers the PSPS patrols and re-energization by approving the re-energization of impacted assets within the event footprint. This approval is termed "Weather all Clear," indicating that a return to weather conditions supporting the commencement of restoration (both the patrol and re-energizing activities) activities in given area(s). Re-energizing activities then commence in the event footprint including conducting patrols and removing and repairing hazards.

The protocol for re-energization when both transmission and distribution assets (including substations) are involved typically includes executing re-energizing of both transmission and distribution assets simultaneously. The transmission element is often prioritized to ensure system stability (including the system protection component) is accounted for and to provide a source for substations and their associated distribution circuits that could be impacted. The transmission line patrol prioritization strategy is driven by electrical system stability (i.e., ensuring adequate transmission facilities are in service to support the overall grid and accompanying local loads along with ensuring that the system protection component is addressed) followed by the customer impacts associated with each line impacted in the event.

Distribution circuit "segmenting" is also used to better align both field and control center personnel in supporting and performing an enhanced safe and efficient by providing for distribution circuit-based isolation (segmentation) and using a circuit-based patrol personnel hierarchy structure. The segmenting process can commence immediately following impacted distribution assets being de-energized as part of a PSPS event as it is done in a de-energized state (while the weather event is ongoing) and typically consists of using previously created distribution circuit segment guides on impacted circuits to open pre-identified distribution field devices downstream of the open source device (used to de-energize given portion(s) of a distribution circuit) to allow for setting up "step restoration" once the "All Clear" is received.

These segment guides use alphabetical identifiers for segments (i.e., Segment "A", Segment "B", etc.). Because the entire distribution circuit may not have been de-energized as part of the PSPS event, the segmenting commences at the next distribution field device.²² Those distribution circuits with assets within HFTD areas will each have an individual segment guide including accompanying maps with the

²² Distribution segment guides are being converted from Fire Index Area (FIA) based to circuit based for 2020 based on lessons learned from the 2019 events. This is driven by the need to move from an "FIA" (Fire Index Area) boundary philosophy to an individual circuit approach which better supports a more targeted meteorological boundary and a more strategic use of PSPS.

pre-identified segments.²³ A given distribution circuit's segments are currently derived by identifying SCADA (remote controlled) field devices and using methodology such as prioritizing for critical customers where possible.

Following the "All Clear," a distribution circuit segment is patrolled (starting at the source side device opened for the event), if no trouble is found PG&E will re-energize that segment up to the next open device (segment boundary). This restoration sequencing is based on the "step restoration" methodology which allows for re-energizing customers in a safe, controlled and efficient manner (rather than waiting to patrol the entire circuit and then re-energizing). This process typically follows the pre-identified segmenting alphabetical sequence (i.e., A-B-C-D, etc.). If damage is found in an individual segment, PG&E may revise the restoration order. This restoration process also provides for a scalable field patrol hierarchy and custom maps detailing both the circuit's individual segment(s) and overall circuit connectivity.

Re-energization information is given to both the field and control center personnel prior to executing the PSPS restoration activities.

The field patrol hierarchy typically consists of the following for a given distribution circuit:

- **Task Force Lead:** A single point of contact for a given PSPS impacted distribution circuit(s) who is responsible for ensuring PSPS patrols are completed and who works with the Control Center to safely re-energize distribution circuit segment(s). A single point of contact allows for significant reduction in communication to the Control Center(s) and promotes increased safety and efficiency due to more focused attention of patrol personnel (both air and ground) engaged in the overall PSPS restoration process.
- **Segment Lead:** Personnel responsible for oversight of assigned patrol personnel (both air and ground) on given segment(s) of a distribution circuit, reports to the Task Force Lead.
- **Patroller:** Individuals (internal, contract and mutual aid) responsible for patrolling assigned portions of a distribution circuit, reports to their assigned Segment Lead.

To support the re-energizing activities, resources needs are identified for the scale and scope of the event footprint during the event pre-planning. Resources typically include helicopters, company personnel, contractors and mutual aid. These resources are then provided to the impacted areas and staged to support the event. Re-energization protocol is largely guided by the following documents:

²³ Given the use of more defined weather forecasting, a given distribution circuit may be de-energized at any point on that circuit so while the segment guide will commence with Segment "A" it may be de-energized at Segment "C" or within a given segment. This allows for more targeted use of PSPS which in turn minimizes customer impacts including those involving critical infrastructure (i.e., public safety, hospitals, communications, water, etc.).

- TD-1464S, "Preventing and Mitigating Fires While Performing PG&E Work" as described in Section 5.3.6.3, Personnel Work Procedures and Training Conditions in Elevated Fire Risk.
- TD-1464B-002, "Public Safety Power Shut-Off for Distribution and Transmission Electric Facilities." This document includes the protocols used by transmission and distribution control center and field/support personnel supporting PSPS restoration (patrols and re-energization) efforts.

Progress Timeline

1. **Before the upcoming wildfire season:** Update TD-1464B-002 to include lessons learned from 2019 PSPS events and latest meteorology inputs (i.e. revised definition of patrol boundary requirements). Begin updating the existing Fire Index Area based Distribution Circuit Segment Guides and maps to circuit based, supporting more detailed meteorology event boundaries. Update the existing Distribution Control Center Operator training materials to incorporate revisions to TD-1464B-002 along with any new materials identified (i.e., potential meteorological and PSPS boundaries including associated segment guide updates as noted above). Confirm that PG&E personnel to complete annual TD-1464S training (see Section 5.3.6.3, Personnel Work Procedures and Training in Conditions of Elevated Fire Risk).
2. **Before the next annual update:** Confirm TD-1464B-002 and the distribution circuit segmentation process are reviewed and updated as appropriate based on lessons learned during the 2020 wildfire season.
3. **Within the next 3 years:** Continue evaluating, updating and improving de-energization protocols and associated guidance documents, process and training activities based on current PSPS tactics and lessons learned.
4. **Within the next 10 years:** Continue evaluating, updating and improving de-energization protocols and associated guidance documents, process and training activities based on current PSPS tactics and lessons learned.

5.3.6.5 PSPS Events and Mitigation of PSPS Impacts

PG&E’s PSPS program proactively de-energizes a portion of our electric system in the interest of public safety when forecasts predict extreme fire-threat conditions. PSPS is utilized by PG&E in accordance with Commission Resolution ESRB-8 “to protect the public safety”, D.19-05-042, and other Commission directives.²⁴ The purpose of proactive de-energization is to promote public safety by decreasing the risk of utility-infrastructure as a source of wildfire ignitions. PG&E will only consider proactively turning off power when the benefits of de-energization outweigh potential public safety risks.

De-energization is determined necessary to protect public safety when PG&E reasonably believes there is an imminent and significant risk of strong winds impacting PG&E assets, and a significant risk of large, destructive wildfires should ignition occur. PSPS is used as a measure of last resort and is only deployed when other measures are not adequate alternatives. PSPS addresses a specific type of risk and, while other measures described in PG&E’s Wildfire Mitigation Plan help reduce the need to de-energize, PSPS remains a unique tool at the utility’s disposal to use in the interest of public safety if extreme conditions are forecasted. A key objective of the PSPS program is to implement measures to dramatically reduce customer impacts of PSPS events without compromising safety. PG&E has developed and is continuing to evaluate accelerated strategies for achieving this objective in 2020 and beyond.

PG&E implemented its PSPS Program in 2018 to proactively de-energize lines that traverse Tier 3 HFTD areas under extreme fire risk conditions. In 2019, PG&E expanded the PSPS program scope to include high voltage transmission lines and the highest fire risk areas (Tier 2 (elevated fire risk) and Tier 3 (extreme fire risk) as referenced in the HFTD Map adopted by the CPUC. PG&E continues to evaluate and mature its program to most effectively eliminate potential ignitions during extreme weather conditions including developing risk-based processes to assess wildfire risk of individual lines and structures.

To develop the PSPS Program, PG&E worked extensively with SDG&E to understand and implement best practices from SDG&E’s de-energization program, while addressing unique issues presented by PG&E’s service area (which differs in terrain, weather, and population). PG&E worked with SDG&E to address issues such as PSPS execution decision factors, stakeholder communication strategies, post-event patrols and inspections, re-energization processes and tools and technology used to promote situational awareness and fire spread modeling.

In 2018 and 2019 PG&E initiated PSPS events that followed the guidelines set forth in the PSPS guidance documents it developed. Since the 2019 WMP submission PG&E executed multiple PSPS events ranging from approximately 10,000 to 1 million customers.

24 See Resolution Extending De-Energization Reasonableness Notification, Mitigation and Reporting Requirements in D.12-04-024 to all Electric IOUs.

Strategies to both reduce scope, duration, and frequency as well as mitigate the impact on customers when they are de-energized are described in Section 5.6.2 Protocols on Public Safety Power Shutoff.

PG&E's 1-year, 3-year, and 10-year vision for the PSPS program are described in Section 4.4 Directional vision for necessity of PSPS.

Progress Timeline

- 1. **Before the upcoming wildfire season:** Continue to implement PSPS according to the protocols and processes currently in place.
- 2. **Before the next annual update:** See Section 4.4, Directional Vision for Necessity of PSPS.
- 3. **Within the next 3 years:** See Section 4.4, Directional Vision for Necessity of PSPS.
- 4. **Within the next 10 years:** See Section 4.4, Directional Vision for Necessity of PSPS.

5.3.6.6 Stationed and On-Call Ignition Prevention and Suppression Resources and Services

Safety and Infrastructure Protection Team (SIPT)²⁵

This in-house team consists of two-person crews composed of IBEW-represented employees who are trained and certified safety infrastructure protection personnel. SIPT crews are used to perform fire mitigation functions and gather critical data to help PG&E prepare for and manage wildfire risk. On a daily basis during normal work hours (e.g., Monday – Friday day shift), SIPT crews are available to respond to emergency situations such as active wildfire response. The SIPT crews will be redirected from their planned assignment to the emergency situation by the WSOC and the SIPT Duty Officer.

During off hours, an On-call system has been established where a specified number of SIPT crews are available across the service territory to respond to emergency call outs. These SIPT crews are compensated with standby pay to be on call. In addition to the on-call crews, other SIPT crews will also be called out to support response if necessary. Finally, if fire danger risk is elevated, the WSOC will identify additional standby personnel to support ready response.

Progress Timeline

- 1. **Before the upcoming wildfire season:** Stabilize the current technology solutions and processes and increase staffing levels to support fire prevention and mitigation activities. Targeted staffing levels and associated equipment needs: 98 SIPT Crew members and 40 Engineers.
- 2. **Before the next annual update:** Continue to stabilize technology, processes and staffing needs.
- 3. **Within the next 3 years:** Continue to assess effectiveness of program and develop risk informed business case to potentially increase staffing levels and equipment needs.
- 4. **Within the next 10 years:** Continue to evaluate the SIPT program and update and modify it as appropriate to address current wildfire mitigation efforts

5.3.7 Data Governance

Description of Programs to Reduce Ignition Probability and Wildfire Consequence
For each of the below initiatives, provide a detailed description and approximate timeline of each, whether already implemented or planned, to minimize the risk of its equipment or facilities causing wildfires. Include a description of the utility's initiatives, the utility's rationale behind each of the elements of the initiatives, the utility's prioritization approach/methodology to determine spending and deployment of human and other resources, how the utility will conduct audits or other quality checks on each

²⁵ SIPT resources are also described in Sections 5.3.2.5; 5.3.6.2.

initiative, how the utility plans to demonstrate over time whether each component of the initiatives is effective and, if not, how the utility plans to evolve each component to ensure effective spend of ratepayer funds.

Include descriptions across each of the following initiatives. Input the following initiative names into a spreadsheet formatted according to the template below and input information for each cell in the row.

- 1. Centralized repository for data
- 2. Collaborative research on utility ignition and/or wildfire
- 3. Documentation and disclosure of wildfire-related data and algorithms
- 4. Tracking and analysis of near miss data
- 5. Other / not listed (only if an initiative cannot feasibly be classified within those listed above)

The list provided is non-exhaustive and utilities shall add additional initiatives to this table as their individual programs are designed and structured. Do not create a new initiative if the utility's initiatives can be classified under a provided initiative.

For each of the above initiatives, describe the utility's current program and provide an explanation of how the utility expects to evolve the utility's program over each of the following time periods:

- 1. Before the upcoming wildfire season,
- 2. Before the next annual update,
- 3. Within the next 3 years, and
- 4. Within the next 10 years.

See Attachment 1 , Table 27 for the details and data associated with the initiatives discussed in this section.

5.3.7.1 Centralized Repository for Data

This section provides an overview of PG&E’s efforts to integrate certain data from different data sources into a single environment, enabling data driven approaches to wildfire mitigation initiatives and efforts. PG&E’s vision for data analytics is focused on a practical data integration approach (utilizing data pipelines from data sources/systems into an integrated data platform) as opposed to a data consolidation approach (eliminating existing data sources/systems and building a single data system for all PG&E data). This section details efforts to advance data integration, in particular two elements that contribute to this capability: (i) Asset Data Foundation, and (ii) data governance practices.

Effective data governance and the enhanced data access provides greater ability to leverage data for risk informed decision-making. Asset Data Foundation further contributes to this capability by bringing together various data critical data into a single environment to support operations and analysis. The long-term objective is to enable advanced data analytics that allow for predictive models to identify at risk assets to further enable proactive asset management practices to mitigate the risk of asset failure and enhance customer safety.

Evolution of Data

As Electric Operations systems and processes related to wildfire mitigation mature, the systems that generate and store data relevant to those mitigation activities continue to grow and evolve. The mitigation of risks associated with wildfire and other events require being able to access and leverage not only data within PG&E but also from external sources. In some instances, existing software systems were not designed to be easily accessed or integrated with other systems, but were purpose built to support specific capabilities. For example, customer data, asset data, work management data, GIS data, operations data and event data have traditionally been managed in separate systems, with independent data stores, without being integrated centrally. Data streams from new technologies, such as remote sensing and LIDAR, introduce emerging data needs for storage and processing, while advanced analytics (including Artificial Intelligence and Machine Learning) offer the potential to leverage data to better manage risk and predict events before they happen. PG&E has responded to these challenges by developing strategies for data governance, management, integration and access. Core to these strategies is an integrated platform for Electric Operations data – the Asset Data Foundation (ADF).

Element Overview: Asset Data Foundation

The Electric Operations ADF is the lead initiative of a broader Enterprise Data Foundation (EDF) strategy responsive to the following drivers: (i) increasing expectations for data availability, data quality and trusted analytics; (ii) increasing demand for advanced analytics, BI, visualizations, dashboards and data sharing; and (iii) increasing need for data security and privacy.

ADF is a governed assembly of data sets where attributes are defined, sources are known, data pipelines are governed, and key connections are established. ADF's data is a product for data users that have need to access multi-faceted data concerning EO assets. A key objective of ADF is to bring together critical physical, operational, lifecycle and environmental data elements into a single environment to better enable cross-functional access to data in support of operations and analysis, as well as providing a layer of data analytics available for self-service. This will be accomplished through the assembly of data from dozens of system sources, curation of this data, and publishing of data systematically with asset and management information. ADF will also establish a layer of governed analytics and data science models that can be accessed through self-service mechanisms.

ADF currently is connected to 20 source systems, which contain over 1.3 billion records relevant to asset health analytics. The number of connected systems, records, and enabled analytics models will continue to grow as WMP projects are added. ADF does not replace the underlying systems of record, but rather provides a central platform to enable data integration/virtualization and access, support for data governance and advanced analytics. There are also several programs to consolidate data of similar types that originate from different systems into a single repository that are underway or proposed. These efforts consolidate data into core systems which are available through ADF for asset and risk analytics functionalities. These programs include:

- GIS Data Mart: To provide a single access point into various GIS systems
- T-Line Outage Database: To develop a Transmission Outage Tool that will provide repository for all recorded outages in the transmission system
- Asset Failure Database: To develop an Asset Failure Database that will provide more insights on reasons for equipment failures
- SAP HANA: moving SAP BW (SAP Business Warehouse) from an on-premise server to cloud environment to streamline ease of integration with data platforms (repositories)

Element Overview: Data Governance Practices

Data governance creates the organization, policies, processes and procedures that can help facilitate the achievement of foundational data capabilities. Select categories of data governance that have the potential to influence the establishment integration of data include: Data Architecture (including data models and cataloging); Data Quality Assurance (including rules, measurements, and remediation); and Data Security (including classification, policies, and lifecycle). Data governance is supported through technology tools such as Colibra Governance, which manages information about data and enhances data accessibility by providing a meta data catalogue with process controls.

Electric Operations is in the process of exploring the development of an organization to help guide electric data governance. This organization would set the standards for data critical to wildfire mitigation and safe operations through the centralized development of data policies, standards, and data cataloging. Data stewards throughout the business

and IT would collaborate with this organization to address data needs and drive data governance outcomes. Having a centralized group to facilitate these functions can help ensure alignment of data strategies across Electric Operations and the enterprise.

Prioritization and Rationalization

The prioritization and rationalization of the elements contributing to the integration of data are summarized as follows:

- Asset Data Foundation: ADF projects have been prioritized and approved based on pilots and outcomes from 2019, including continued assembly of data pertaining to transmission and distribution assets lifecycles and operations, enabling self-service data access and analysis, and machine learning and predictive analytics data models to support prioritization of inspection and repair/replacement work.
- Data Governance: Projects will undergo an “Intake and Prioritization” process that supports identification and selection of different data projects. The development of data policies, standards, and business definitions established through data governance practices will inform the strategic selection of data projects and help drive the direction of data platform priorities.

Audits / Measuring Effectiveness

Wildfire mitigation programs and initiatives are bolstered through the accessibility and accuracy of electric data. The success of the asset data foundation and data governance elements is in part driven by the quality of this data, its timely availability, and the ability to combine data from disparate sources. If either element does not meet success targets, PG&E will conduct an analysis to identify the causes of inefficiency or ineffectiveness and implement efforts to improve the methodology.

Audits are planned for data program, project, or initiative phases to further ensure effectiveness. These audits will be based on qualitative and quantitative parameters such as the following:²⁶

- Qualitative parameter: Measure adoption by tracking number of users logging in and track data sets requested and used as a measurement of usefulness of the data offered
- Quantitative parameter: Assess the strategic value associated with investments made in data platforms and governance functions, including use case enablements and foundational value to long term objectives

Longer term, PG&E may be able to directly measure outcomes of actual asset lifecycle statistics and compare with predictions in data science models to inform effectiveness reviews. If a program, project, investment, or strategy is found to be ineffective, PG&E will analyze and consider improvements to both the immediate underlying factors and

²⁶ Parameters for effectiveness review are subject to change.

future prioritization/selection methodology, helping to ensure efficient spend of ratepayer funds.

Progress Timeline

- 1. **Before the upcoming wildfire season:** Continue development of integrated data platform(s) (repository) in support of single view of multiple sources systems containing relevant data. Continue efforts to correct known data issues that may have impacted PG&E's ability to execute PSPS notifications, including: (i) correcting electric connectivity data to ensure that the scope of PSPS events is as accurate as possible; (ii) ongoing evaluation of different methods for producing maps with higher levels of precision for the potential outage impacts; (iii) offering expanded support for counties affected by PSPS events and working on data sharing processes.²⁷
- 2. **Before the next annual update:** Continue testing of integrated data platform(s) (repository), including initial data analytics capability. Increase data inputs and continuously update event data.
- 3. **Within the next 3 years:** Develop mature analytics tools serving integrated data platform(s) (repository).
- 4. **Within the next 10 years:** Continue to develop integrated data platform(s) (repository) with the objective of bringing together all relevant data into a single environment to better enable cross-functional access to data in support of operations and analysis, and in addition provide a layer of data analytics available for self-service.

²⁷ Additional information about these PSPS issues can be obtained through CPUC Rulemaking 18-12-02/5 (Order Instituting Rulemaking to Examine Electric Utility De-energization of Power Lines in Dangerous Conditions).

5.3.7.2 Collaborative Research on Utility Ignition and/or Wildfire

PG&E is engaged in various collaborative research projects related to utility ignition and/or wildfire risk. PG&E regularly benchmarks wildfire risk issues with other California utilities, both informally and through the RAMP proceeding. PG&E also reviews information from and engages in benchmarking discussions with, other U.S. and foreign (e.g., Australian) utilities that may face similar wildfire issues to PG&E. In addition, PG&E sometimes engages with other utilities and/or outside experts to perform research, including the following examples:

- **Leveraging nuclear industry risk modelling to develop wildfire risk assessment:** PG&E is partnering with the B. John Garrick Institute for the Risk Sciences, University of California Los Angeles (UCLA) to leverage the rigorous modeling used in the nuclear industry to perform thorough and complex wildfire risk assessments and management planning. PG&E has used a probabilistic risk assessment model for over 30 years at its Diablo Canyon Nuclear Power Plant. The model is constantly updated with current plant design and state of the art analysis methodologies. Data from 30 years of industry and plant specific experience is used to model component reliability and unavailability. The model can perform quantitative assessment of risks from a multitude of complex factors, including internal plant failures, seismic events, fire and flooding. Each model element has been independently reviewed by industry peer review teams and the results have been audited on numerous occasions by the Nuclear Regulatory Commission. The model is capable of quantitatively risk ranking over 3,000 individual system components including the transmission lines that supply Diablo Canyon with offsite power. PG&E is working with risk experts at UCLA to develop a similar model for wildfire risks for its electrical assets within HFTD areas.
- **Wildfire Evacuation Study:** PG&E partnered with several renowned traffic simulation and evacuation experts to collaborate with a high fire risk community to perform a detailed wildfire evacuation study to examine anticipated traffic conditions and evacuation times associated with various rates of evacuation responses and alternative management strategies that could be used in response to them. The intent of this work is to develop a procedure or methodology that can be applied to any community with a high fire risk to improve their wildfire emergency plans and to inform PG&E's egress risk methodology with additional granularity. The evacuation study report will document the demand estimation methodology (how many people and vehicles need to be evacuated), the highway capacity estimation, mobilization (trip generation) time distributions and the computed evacuation time estimates (ETE) in tabular and graphical format. The report will also contain a description of the traffic simulation and trip distribution and assignment algorithms utilized in the modeling system, the technical details of the study and the supporting data. In addition, the report will identify traffic bottlenecks during evacuation and include a detailed discussion of potential improvements to evacuation time.
- **Distribution Arcing Fault Signature Library:** As discussed in Section 5.3.2.2.8—PG&E is partnering with two National Laboratories to install a high-fidelity optical sensor technology on a distribution feeder for the completion of a Distribution Arcing Fault Signature Library. The Distribution Arcing Fault Signature Library will inform PG&E about the types and resolutions of sensors needed to detect incipient fault

conditions on the distribution system and intervene with proactive maintenance to reduce wildfire risks.

Progress Timeline

- 1. **Before the upcoming wildfire season:** PG&E will continue to pursue both formal and informal benchmarking and collaborative research efforts related to wildfire risk.
- 2. **Before the next annual update:** See above.
- 3. **Within the next 3 years:** See above.
- 4. **Within the next 10 years:** See above.

5.3.7.3 Documentation and Disclosure of Wildfire-Related Data and Algorithms

PG&E collects voluminous data related to wildfire and wildfire risk management. At the most basic level, PG&E collects wildfire ignition data and reports it to the CPUC. PG&E also collects data on system operations, outages, asset condition and other factors that we are using to develop and prioritize wildfire mitigations. PG&E's process for developing and prioritizing mitigations has been documented and shared with the Commission and other interested parties both here and in various other proceedings, including the 2020 GRC and the 2019 RAMP.²⁸ PG&E is continuing to refine its data collection and evaluation methodologies, and will continue to report on them in upcoming proceedings.

Progress Timeline

- 1. *Before the upcoming wildfire season:* PG&E will continue to refine its data collection and evaluation methodologies and will continue to report on them in upcoming proceedings.
- 2. *Before the next annual update:* See above.
- 3. *Within the next 3 years:* See above.
- 4. *Within the next 10 years:* See above.

²⁸ For example, the types of data that PG&E uses as the basis for its circuit prioritization model for wildfire mitigations are described in Section 5.3.3.17. The model itself was shared with the Commission as part of the 2020 GRC.

5.3.7.4 Tracking and Analysis of Near Miss Data

PG&E has not established a technical, operational definition of "ignition near miss" events and therefore does not track near miss data related to ignition probability and wildfire consequence. PG&E currently uses outage events as a proxy for near miss events as a larger population of system events to be analyzed in relation to assessing wildfire risk.²⁹ Moving forward through this WMP period PG&E will be working to establish a technical, operational definition of "ignition near miss" events and will establish processes and tools to capture, track and analyze such events.

Progress Timeline

- 1. *Before the upcoming wildfire season:* No immediate changes planned.
- 2. *Before the next annual update:* Through this WMP period PG&E will be working to establish a technical, operational definition of "ignition near miss" events and will establish processes and tools to capture, track and analyze such events.
- 3. *Within the next 3 years:* See above.
- 4. *Within the next 10 years:* Continued evolution in near miss tracking and analysis depending on learnings over the coming years.

²⁹ Note that for the purposes of determining ignition probability drivers in Table 11 in Section 3.2, PG&E has taken the approach that an outage is a proxy for a near miss. Further, near misses in this context are only limited to outages.

5.3.8 Resource Allocation Methodology

Description of Programs to Reduce Ignition Probability and Wildfire Consequence

For each of the below initiatives, provide a detailed description and approximate timeline of each, whether already implemented or planned, to minimize the risk of its equipment or facilities causing wildfires. Include a description of the utility's initiatives, the utility's rationale behind each of the elements of the initiatives, the utility's prioritization approach/methodology to determine spending and deployment of human and other resources, how the utility will conduct audits or other quality checks on each initiative, how the utility plans to demonstrate over time whether each component of the initiatives is effective and, if not, how the utility plans to evolve each component to ensure effective spend of ratepayer funds.

Include descriptions across each of the following resource allocation methodology and sensitivities initiatives, including a description of the data flow into the calculations involved in each. Input the following initiative names into a spreadsheet formatted according to the template below and input information for each cell in the row.

- 1. Allocation methodology development and application
- 2. Risk reduction scenario development and analysis
- 3. Risk spend efficiency analysis
- 4. Other / not listed [only if an initiative cannot feasibly be classified within those listed above]

For each of the below initiatives, describe the utility's current program and provide an explanation of how the utility expects to evolve the utility's program over each of the following time periods:

- 1. Before the upcoming wildfire season
- 2. Before the next annual update
- 3. Within the next 3 years
- 4. Within the next 10 years

The list provided is non-exhaustive and utilities shall add additional initiatives to this table as their individual programs are designed and structured. Do not create a new initiative if the utility's initiatives can be classified under a provided initiative. Where the columns listed do not apply or cannot be meaningfully calculated for a given resource

allocation methodology and sensitivities initiative. "N/A" may be logged in the corresponding cell.

For each of the above initiatives, describe the utility's current program and provide an explanation of how the utility expects to evolve the utility's program over each of the following time periods:

- 1. Before the upcoming wildfire season,
- 2. Before the next annual update,
- 3. Within the next 3 years, and
- 4. Within the next 10 years.

See Attachment 1, Table 28 for the details and data associated with the initiatives discussed in this section.

5.3.8.1 Allocation Methodology Development and Application

Allocating resources to wildfire risk mitigation activities is one aspect of PG&E’s overall resource allocation process. Resource allocation and balancing requires identifying resource supply (ability to perform work) and resource demand (how much work to complete).

Resource supply is identified for major working groups, particularly the construction and estimating resource groups within Electric Operations’ Transmission Operations, Distribution Operations and Major Projects & Programs organizations. These are the main resources that perform work execution on electric assets.

Focusing on construction resource supply as a key example, we identify the maximum level of work that could be completed within a given timeframe (i.e., month or year) with current available or assumed resources (i.e. after planned hiring is completed). The 2020 plan used a combination of current headcount and crew availability and assumed incremental hiring of PG&E electric construction personnel. Construction resource supply is calculated for both internal (PG&E) and external/contract construction crews. Additionally, resource supply is calculated at the division level and can be summarized at the region or system level. Some factors incorporated into the construction resources supply model include: headcount, work / paid days, overtime, productive time, external resources, number of crews, external resources work schedule and external resources productivity level.

On the other hand, construction resource demand is developed from the full amount of work targeted to be worked in a given timeframe based on the planned and forecasted work volumes. In other words, resource demand is the amount of work PG&E expects to be worked in the unit of man hours.

Matching up resource supply and demand is performed by allocating resources to the highest priority work (including wildfire ignition prevention mitigations) until all resources have been accounted for. This prioritized volume of targeted work demand is compared against supply for every division. The prioritized target demand (of work) generally exceeds supply (of resources) which requires further prioritization of planned and forecasted work to support the development of an executable work plan. The initial prioritization of work from highest to lowest priority is then followed by optimization scenario analysis leveraging a value and risk modelling platform to understand investment and timing options. These options are reviewed with leadership to select the preferred scenario(s) for optimizing the workplan and balancing resources to create an executable workplan.

5.3.8.2 Risk Reduction Scenario Development and Analysis

In order to make risk informed decisions to minimize the risk of electrical equipment causing wildfires, PG&E is developing risk models that can produce scenarios for decision-making with the following characteristics:

- 1. Granularity: PG&E is developing models at the asset level, which will allow PG&E to view probabilities, consequences, and risk assessments across a range of levels from the asset up to the system level. Asset level assessments allow for increased capability to measure risk improvement from asset replacement or maintenance. While averaging risk across circuits can be effective, it requires estimating the risk reduction of a project or program of work. An asset level view of risk will give PG&E the opportunity to develop project scopes and programs that will efficiently reduce the risk of ignitions caused by equipment.
- 2. Time periods: PG&E is working to develop model scenarios across a range of time periods – planning, operational, and event.
 - a. Planning scenarios: It is useful to assess worst case conditions, such as for fire season, in a planning view. The planning scenarios will provide the basis for work planning on an annual and multi-year schedule. Planning scenarios enable the optimization of multi-year work plans to reduce risk. PG&E envisions a mature set of tools to enable optimization of the multi-year workplan by evaluating alternative work plans to identify which combination of mitigation work will provide the most effective reduction of wildfire risk over time.
 - b. Operational scenarios: PG&E needs to know the current risk levels for operational purposes. Operational scenarios will provide the basis for tracking wildfire risk and identifying areas for inspection tag prioritization and operational action such as switching if an area shows an elevated risk of wildfire.
 - c. Event scenarios: Finally, PG&E needs to assess conditions during events such as PSPS activations. Event scenarios will provide the basis for PSPS activations, de-energization decisions and responding to ignitions.

Scenarios developed during these three time periods: planning, operational, and events will provide for risk informed decisions on an annual, daily and event basis to reduce the risk of equipment caused wildfires.

Data Requirements

Risk scenarios require data from the following sources: asset data, inspection results, vegetation data, and meteorology data. For the planning scenarios these data sets will represent future system conditions. These future data sets will be influenced by load forecasting, climate modeling, and meteorological modeling. For the operational scenarios the data sets will represent current system conditions including, daily and weekly load and generation forecasts, hourly, daily and weekly meteorology forecasts and current status on vegetation and electric system work. For example, this data would show the improvement in risk reduction as work is completed through the year. Operational scenarios will show risk reduction from completed work in the next month.

How Used in Prioritization

With each of the time period models, alternative scenarios can be developed to assess relative risk and accompanying mitigation costs. Applying the risk spend efficiency process outlined in Section 5.3.8.3 the capabilities of each scenario can be viewed and a risk informed decision can be made. For the planning model it might involve multi-year work plans or mid-year plan adjustments to respond to system conditions or shifted work schedules. For the operational model scenarios will provide for risk informed decisions on outage planning for work or shifts in load or generation forecasts responding to meteorological conditions. Scenarios modelled during events could inform PSPS activation and de-energization decisions or decisions about how to prioritize safety observers from the WSOC.

Verification and Precision

Another function of the operational level model is to serve as a tool to measure the precision of the risk models. Each day, operational models will represent the probability of equipment failure, vegetation events and ignitions on the transmission and distribution system. The actual equipment failures, vegetation events and ignitions provide for a feedback on model performance. Constructing an ongoing measure of model precision as part of the operational model will provide a measure of confidence as part of making informed decisions based on the risk scenarios, data driven feedback for model improvement, and eventually an environment for machine learning methods to be incorporated in to the models.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E currently employs transmission and distribution risk models capable of producing operational scenarios at the circuit level. Before the next fire season, PG&E will attempt to produce planning, operational, and event models at the circuit level. Because this level of functionality is a key component of improvements to PSPS, most of PG&E's work in the near term will be focused on creating event scenarios to inform PSPS decisions.
2. **Before the next annual update:** In preparation for the 2021 workplan, PG&E plans to develop the planning scenarios to evaluate different workplan scenarios at the asset level.
3. **Within the next 3 years:** PG&E plans to develop asset based operational, planning and event scenarios to a decision level of precision and quality. The verification and precision functionalities of the operational model will also be refined in the next 3 years.
4. **Within the next 10 years:** PG&E will continue to employ advanced modeling and machine learning algorithms to refine data inputs, model accuracy and scenarios tools.

5.3.8.3 Risk Spend Efficiency Analysis

Risk Spend Efficiencies (RSEs) represent the calculated risk reduction per dollar spent on an initiative. RSEs are calculated by the S-MAP aligned risk model. RSEs represent the calculated risk reduction associated with the implementation of a mitigation per dollar spent on that mitigation and are determined for each Mitigation by dividing the Risk Reduction by the total cost of the Mitigation program.

Risk reduction for a mitigation is calculated based on the difference between the pre-Mitigation Risk Score and Post-Mitigation Risk Score, for each year. To calculate the post-Mitigation Risk score, PG&E estimated the effectiveness of the proposed mitigations for each ignition driver by assembling a cross-functional team of experienced professionals from across the Company and established risk assessment and management consulting service providers. The team reviewed each of the CPUC-reportable ignition events for PG&E from 2015 – 2018 and assessed whether the given mitigation program would have potentially prevented the ignition.

When a Mitigation includes multiple programs, Total Risk Reduction is allocated to each program based on its marginal contribution to the risk score. The Net Present Value (NPV) of the Risk Reductions are then used for calculating Risk Spend Efficiency (RSE) of each program per the formula below.

- Risk Reduction = Total Risk Reduction x Risk Reduction Allocation Factor
- Risk Spend Efficiency (RSE) = NPV of Risk Reduction / NPV of Program Costs

Risk Reduction is calculated for each calendar year and represented as a present value in current year using the utility discount rate of 7.1% for calculating RSE. The utility discount rate is PG&E's after-tax weighted cost of capital.

Currently, RSEs have been calculated for four mitigation programs related to wildfire risk:³⁰

1. System Hardening in PG&E's distribution system in HFTD areas
2. Enhanced Vegetation Management (EVM) for PG&E's distribution system in HFTD areas
3. Non-Exempt Surge Arrestor Replacement in distribution system (in PG&E's entire service territory);
4. Public Safety Power Shut off (PSPS) in Distribution and Transmission systems (in HFTD areas).

More background on risk quantification, which is a pre-requisite to calculating RSE is provided in Section 5.3.

³⁰ RSEs presented in this filing are projections based on the current model, which will continue to be enhanced and validated with actual data. The RSEs in this filing should be seen as indicative of trends, rather than as forecasts of ignition probability.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E will continue to refine its RSE calculations and analysis. Updated descriptions will be included in PG&E's upcoming 2020 RAMP filing.
2. **Before the next annual update:** PG&E expects to incorporate RSEs into its Risk Informed Budget Allocation (RIBA) process and implement IT systems to support Risk Spend Accountability Reporting (RSAR) per D.19-4-020 and future project portfolio optimization initiatives.
3. **Within the next 3 years:** As part of the next S-MAP proceeding, PG&E expects to implement Risk Mitigation Accountability Reporting (RMAR), portfolio optimization and risk tolerance policies.
4. **Within the next 10 years:** PG&E expects that RSEs will play an integral role in its decision making and resource planning process.

5.3.9 Emergency Planning and Preparedness

Include a general description of the overall emergency preparedness and response plan, and detail:

- 1. A description of how plan is consistent with disaster and emergency preparedness plan prepared pursuant to Public Utilities Code Section 768.6, including:
 - a. Plans to prepare for and restore service, including workforce mobilization (including mutual aid and contractors) and prepositioning equipment and employees
 - b. Emergency communications, including community outreach, public awareness, and communications efforts before, during, and after a wildfire in English, Spanish, and the top three primary languages used in California other than English or Spanish, as determined by United States Census data
 - c. Showing that the utility has an adequate and trained workforce to promptly restore service after a major event, taking into account mutual aid and contractors
- 2. Customer support in emergencies, including protocols for compliance with requirements adopted by the CPUC regarding activities to support customers during and after a wildfire, including:
 - a. Outage reporting
 - b. Support for low income customers
 - c. Billing adjustments
 - d. Deposit waivers
 - e. Extended payment plans
 - f. Suspension of disconnection and nonpayment fees
 - g. Repair processing and timing
 - h. Access to utility representatives
- 3. Coordination with Public Safety Partners, such as stationing utility personnel in county Emergency Operations Centers

Describe utility efforts to identify which additional languages are in use within the utility's service territory, including plan to identify and mitigate language access challenges.

Description of Programs to Reduce Ignition Probability and Wildfire Consequence

For each of the below initiatives, provide a detailed description and approximate timeline of each, whether already implemented or planned, to minimize the risk of its equipment or facilities causing wildfires. Include a description of the utility's initiatives, the utility's rationale behind each of the elements of the initiatives, the utility's prioritization approach/methodology to determine spending and deployment of human and other resources, how the utility will conduct audits or other quality checks on each initiative, how the utility plans to demonstrate over time whether each component of the initiatives is effective and, if not, how the utility plans to evolve each component to ensure effective spend of ratepayer funds.

Include descriptions across each of the following initiatives. Input the following initiative names into a spreadsheet formatted according to the template below and input information for each cell in the row.

- 1. Adequate and trained workforce for service restoration*
- 2. Community outreach, public awareness, and communications efforts*
- 3. Customer support in emergencies*
- 4. Disaster and emergency preparedness plan*
- 5. Preparedness and planning for service restoration*
- 6. Protocols in place to learn from wildfire events*
- 7. Other / not listed [only if an initiative cannot feasibly be classified within those listed above]*

The list provided is non-exhaustive and utilities shall add additional initiatives to this table as their individual programs are designed and structured. Do not create a new initiative if the utility's initiatives can be classified under a provided initiative.

For each of the above initiatives, describe the utility's current program and provide an explanation of how the utility expects to evolve the utility's program over each of the following time periods:

- 1. Before the upcoming wildfire season*
- 2. Before the next annual update*

- 3. *Within the next 3 years*
- 4. *Within the next 10 years.*

This section describes PG&E's overall emergency preparedness and response plan. Detail is provided below regarding how PG&E's emergency response plan aligns with PUC Section 768.6, the support provided to customers during emergencies, engagement applied with public safety partners, as well as the approaches PG&E takes to identify and mitigate language access challenges. PG&E further describes six initiatives as it related to emergency planning and preparedness, including their anticipated evolution over time: (1) adequate and trained workforce for service restoration; (2) community outreach, public awareness, and communications efforts; (3) customer support in emergencies; (4) disaster and emergency preparedness plan; (5) preparedness and planning for service restoration; and (6) protocols in place to learn from wildfire events.

See Attachment 1, Table 29 for the details and data associated with the initiatives discussed in this section.

Emergency Plan Alignment with Public Utilities Code Section 768.6

In alignment, with PUC Section 768.6, which are standards for disaster and emergency preparedness plans, PG&E prepares for, responds to, and restores service during emergencies as documented in its Company Emergency Response Plan (CERP). The CERP is inclusive of the Electric Annex, Disaster Rebuild Annex, Public Safety Power Shutoff (PSPS), and other annexes that support the CERP. PG&E manages its Mutual Assistance agreements with other utilities through the California Utility Emergency Association (CUEA), Western Regional Mutual Assistance Agreement (WRMAA) and the Edison Electric Institute (EEI). Combined, these agreements provide PG&E with access to over 80% of the public utility industry across the United States and Canada.

PG&E utilizes a contractor workforce through its Contract Management office, ensuring that sufficient personnel are available for contingency operations. Electric Operations and Supply Chain Logistics divisions are each responsible for the pre-positioning of crews and equipment and such decisions are made based on the scope and location of a given incident. PG&E maintains numerous Service Centers and equipment warehouses throughout its service territory for such contingencies. Additionally, PG&E activates Base Camps, micro-sites, and equipment laydown yards on an *ad hoc* basis as the needs of each situation may dictate.

When PG&E's EOC is activated, PG&E utilizes a mass notification system (Send Word Now) to inform employees and public safety partner agencies about incidents taking place. This platform uses voice, text and email messaging to notify recipients of major events affecting their area. During any emergency incident, PG&E notifies customers (where possible) to provide incident-related updates if long-duration outages are anticipated, which may include the cause of the outage, estimated times of restoration and notification once power is restored (where possible). If a customer has set their notification preferences to receive outage-related updates, a customer will receive automated notifications with status of the outage. During a PSPS event, however, all forms of contact information available for a customer are utilized for direct notifications to potentially impacted customers.

PG&E provides emergency communications and a variety of outreach tactics to customers before, during and after an emergency (including wildfires), such as: community outreach, website, letters, factsheets, handouts, proactive news stories, social media, and translated outreach in multiple languages. PG&E Advice Letter 4139-G/5630-E more fully describes the emergency-related outreach plan, including the translation support provided before, during and after a disaster, including wildfires.

PG&E ensures unity of command, continuity of operations and a common operating picture through use of the National Incident Management System (NIMS), Incident Command System (ICS) and Standardized Emergency Management System (SEMS); this includes mutual assistance and contractor crews. These incident command system principles are applied to all emergency operations, ranging from Base Camp EOCs, to Operational Emergency Centers, to the main PG&E EOC. All PG&E personnel engaging in EOC operations are trained in the basic concepts of ICS. Electrical service contractors are required to meet established qualification criteria for inclusion in PG&E's contractor program, of which approximately 270 are qualified to perform restoration work. PG&E's Electric Operations divisions (Transmission and Distribution) also employ crews to perform emergency restoration work as needed in the aftermath of incidents.

Customer Support in Emergencies

Support for customers impacted by an emergency, including wildfires, is an important element of PG&E's post-incident emergency response. Following the October 2017 Northern California wildfires, PG&E established a series of billing and service modifications and disaster relief to support impacted customers. These measures, included in PG&E's Emergency Consumer Protection Plans, were adopted with Advice 3914-G-A/5186-E-A, effective December 22, 2017, in compliance with Commission Resolution M-4833, Emergency Authorization and Order Directing Utilities to Implement Emergency Consumer Protections to Support Residential Customers of the October 2017 California Wildfires. On September 7, 2018, PG&E revised its Emergency Consumer Protection Plan, as approved by Advice 3914-G-A/5186-E-A, for residential and non-residential customers in areas covered by a state of emergency issued by the Governor³¹ due to a disaster, such as a wildfire, that affects utility services.

Disaster-related emergency declarations are becoming more frequent in California. The protections adopted in the 2017 resolutions were limited narrowly to the specific incidents identified in the resolutions, the CPUC established interim measures in D.18-08-004, which affirmed the provisions of Resolutions M-4833 and M-4835 as temporary disaster relief protection measures for customers until the proceeding under R.18-03-011 developed a permanent emergency disaster relief program. On July 11, 2019, the Commission issued D.19-07-015, adopting a permanent emergency disaster

³¹ D.19-07-015 revised the authorization of who declares the state of emergency to also include the President of the United States.

relief program for utility customers and included the adoption of PUC Section 8386(c)(18) as part of this program.³²

The provisions under the permanently established Emergency Consumer Protections program "shall be implemented upon a Governor of California's state of emergency declaration or a Presidential State of Emergency declaration, when a disaster has either resulted in the loss or disruption of the delivery or receipt of utility service and/or resulted in the degradation of the quality of utility service."³³ Upon each declared disaster, such as a wildfire, utilities are required to file a Tier 1 Advice Letter within 15 days of the state of emergency proclamation and a secondary Tier 1 Advice Letter after the conclusion of the disaster or at the default, 12-month conclusion of the customer protection period to report compliance. PG&E will meet these requirements in the event of a wildfire or other emergency.

Most of the requirements identified in PUC Section 8386(c)(18), among others, are addressed in PG&E's Revised Emergency Consumer Protections Plan in alignment with Resolutions M-4833 and M-4835 and D.19-07-015. The associated Advice Letters and D.19-07-015³⁴ more fully describes the customer support services provided by PG&E to eligible customers upon the declaration of an emergency. Below, PG&E addresses each of the issues identified in the WMP Guidelines:

- A. Outage Reporting: While PG&E's revised Emergency Consumer Protection Plan does not discuss outage reporting specifically, PG&E leverages its existing outage reporting systems to notify customers of an actual electric outage caused by a PSPS event, or other planned or unplanned outages. For PSPS events, PG&E implements the notification guidelines as described in the De-energization Phase 1 Guidelines (D.19-05-042). In addition to customer notifications, PG&E includes emergency alerts and outage information on its website. PG&E continues to leverage different indicators (colors) on the outage map to distinguish which type of outage may be occurring (e.g., PSPS planned outage or unplanned outages);
- B. Support for Low-Income Customers: PG&E provides support for low-income customers, including freezing CARE eligibility standards and high-usage post enrollment verification (PEV) requests, increasing the assistance cap for emergency assistance program, and modifying qualification requirements for the ESA Program by allowing customers to self-certify they meet income qualifications;
- C. Billing Adjustments: PG&E stops estimated energy usage for billing attributed to the time period when the home/unit was unoccupied as a result of the disaster;

³² PUC Section 8386(c)(18) requires IOUs to provide "activities to support customers during and after a wildfire, outage reporting, support for low-income customers, billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, repair processing and timing, access to utility representatives, and emergency communications."

³³ p. 2.

³⁴ Resolution M-4833 (pp. 5-8); Resolution M-4835 (pp. 4-8).

- D. Deposit Waivers: PG&E waives security deposit requirements to re-establish service for customers whose home(s) or small business(es) were destroyed by the disaster;
- E. Payment Plans: PG&E provides favorable payment plan options to eligible customers, including customers whose employment was impacted by a disaster, for any outstanding balances on their accounts. As required by D.19-05-037 (OP 24), PG&E Advice Letter 4145-G/5643-E extends bill payment arrangements to customers' whose employment was impacted by a disaster, including wildfires;
- F. Suspension of Disconnection and Nonpayment Fees: PG&E suspends disconnection for non-payment and associated fees, and providing waiver of returned check or late fee requirements for customers whose homes or small businesses were destroyed by the disaster;
- G. Repair Processing and Timing: Although PG&E's revised Emergency Consumer Protection Plan does not specifically discuss repair processing and timing, it does include the customer protections to expedite move-in and move-out service requests for the next business day, or another date selected by the customer, as well as the offering to reestablish service under prior rate (if requested) and waive the cost for temporary power under Electric Rule 13. Additionally, during a PSPS event, PG&E currently uses its best efforts to communicate the Estimated Time of Restoration (ETOR) to customers. Restoration timing for the entire affected area is estimated by calculating the projected restoration work hours and dividing by the available restoration crews. Following a wildfire, PG&E utilizes their existing repair and rebuild process and works with the impacted community to communicate priorities and timelines for repairs and restoration, prioritizing repairs with those customers impacted by a disaster or wildfire.

Repair timing is largely dictated by access to the fire area, total damage to PG&E assets, length of the affected lines, ability to secure materials and repair resources, and the priority of the customer. For example, hospitals, schools, water treatment plants, communication providers, jails and other facilities deemed critical by the CPUC and local community will receive a higher priority for restoration.

D.19-05-042 defines critical facilities as "facilities that are essential to the public safety and that require additional assistance and advance planning to ensure resiliency during de-energization events" and adopts an interim list of critical facilities that meet this definition.³⁵ In the event the fire's damage exceeds the restoration capacity of the local division, a base camp may be established to support the restoration crews, equipment, materials, housing, and incident command staff.

H. Access to Utility Representatives: Although PG&E's revised Emergency Consumer Protection Plan does not discuss access to utility representatives specifically, multiple channels of communication are available to its customers and communities before, during and after a wildfire, and include, but are not limited, to: PG&E's call

³⁵ pp. A4-A6.

center and website, customer service offices, public affairs and customer account representatives, and field teams.

In D.18-08-004,³⁶ the CPUC encouraged utilities to consider additional ways to assist customers impacted by a disaster. In addition to the above noted consumer protections described in PG&E's revised Emergency Consumer Protections Plan, PG&E also offers consumer protections for solar customers in the event their premise is destroyed by a natural or man-made disaster. On April 25, 2019, the CPUC approved PG&E Advice 5404-E that, through revisions to its tariff provisions in the Net Energy Metering (NEM) Tariff and NEM Successor Tariff (NEM2), grants PG&E the opportunity to offer the following three additional protections to solar customers:

1. Allowing customers to size their replacement system to the annual load of their new premise and remain on NEM, without being required to move to the successor tariff (NEM2) if the newly-sized system exceeds the sizing upgrade threshold;
2. Removing the interconnection application fee when reapplying to resume service on NEM2 (with some restrictions); and
3. Updating the interconnection application forms to allow Disaster-impacted customers to identify themselves during the interconnection process and benefit from these provisions.

Coordination with Public Safety Partners

PG&E is committed to coordination and collaboration with public safety partners through both emergency preparedness outreach and PSPS event notification and coordination.

Emergency Preparedness Outreach

Public Safety Partners, as defined by the D.19-05-042, include "first/emergency responders³⁷ at the local, state and federal level, water, wastewater and communication service providers, affected community choice aggregators and publicly-owned utilities/electrical cooperatives, the Commission, the California Governor's Office of Emergency Services and the California Department of Forestry and Fire Protection." PG&E's emergency preparedness outreach, includes, but is not limited to:

- One-on-one meetings to have more localized discussions and listening sessions with jurisdictions and agencies impacted by previous PSPS events. PG&E will utilize these meetings to gather feedback and adjust the program, as appropriate;
- More robust PSPS scenario planning (tabletop) exercises with County Offices of Emergency Services (OESs), tribes and other public safety partners;

³⁶ p. 4.

³⁷ "Emergency response providers" include federal, state, and local governmental and nongovernmental public safety, fire, law enforcement, emergency response, emergency medical services providers (including hospital emergency facilities), and related personnel, agencies, and authorities.

- Direct outreach to County OES agencies, tribal agencies, and public safety partner customers, such as telecommunications providers and water agencies, to confirm contact information, as needed;
- Presentations at public meetings (e.g., city council meetings, board of supervisor meetings);
- Working with counties and tribes to identify critical facilities to assist with prioritizing restoration (as feasible) during an event;
- Share progress of local field work (e.g., system hardening, enhanced vegetation management);
- Providing access to the secure data transfer portal (PSPS Portal) in order to share additional customer information quickly during an event;
- Providing sample notifications and planning maps;
- Seeking and incorporating feedback where feasible to ensure agencies have information and procedures to proactively plan for and respond to a PSPS event; and
- Coordinating with counties and tribal agencies to pre-identify more permanent Community Resource Center (CRC) locations to utilize during an event.

PSPS Event Notification and Coordination Strategy

PG&E is committed to providing notification to potentially impacted stakeholders in advance of, during and after a PSPS event, as weather permits. Advanced priority notification will be provided to public safety partners in alignment with CPUC guidelines, as time and weather permits. The PSPS notification strategy will comply with CPUC rulings, as weather permits.

PG&E expanded its notification strategies for 2019 and continues to adjust as the company received feedback from state and local agencies, as well as its customers. For 2020-2022, PG&E will utilize the strategies below and will modify as the company works towards shorter event durations and fewer customers impacted. PG&E will continue to use all communication channels available during an event: direct to customer notifications, media (multi-cultural news outlets, earned and paid media, social media), website, collaboration with Public Safety Partners and Community Based Organizations (CBOs).

State agencies, cities, counties and tribes will be notified in advance of residential customers regarding a potential PSPS event in order to aid in preparedness efforts. PSPS event notification and coordination may include but is not limited to:

- Providing
- Providing updates to the state via the Cal OES form throughout the event;
- Issuing automated notifications throughout the event via phone, text and email;

- Providing the content of customer alerts to share via the city, county or tribal website, Nixle, and Nextdoor;
- dedicated single points of contact for potentially impacted counties and tribes to provide event-specific and agency-specific information in real-time throughout the event;
- Hosting county and tribal representatives in PG&E's EOC, if requested;
- Offering PG&E representatives, such as Liaison and GIS experts, to be available to be embedded in local and tribal EOCs, as needed;
- Posting maps and event-specific information on the secure data transfer portal (PSPS Portal) and website, including potentially impacted critical facilities and Medical Baseline customer information will also be posted on the portal;
- Coordinating with agencies and tribes on Community Resource Center locations;
- Managing a dedicated 24-hour PG&E Liaison email address where partners can reach PG&E EOC staff with any questions or requests for information; and
- Hosting local agency and/or State Executive calls, as needed, to provide situational awareness for the event.

Additional public safety partners, such as water agencies, communication providers, CCAs, and Municipal Utilities will receive the following notifications and support by PG&E during a PSPS event:

- Notification in advance of residential customers for preparedness efforts;
- Maps of potentially impact areas in advance of customers; and
- Dedicated single points of contact to communicate frequently via live calls for situation awareness updates and operational support.

Language Access and Translations Strategy

PG&E recognizes the diverse nature of its service territory and is committed to keep pace with changing demographic trends. To determine if a language is prevalent³⁸ in its service territory, PG&E uses the Federal Voting Rights Act, Section 203 standards for Minority Languages as its guide, based on census data related to counties served by PG&E. In addition, PG&E uses language preference data associated with PG&E's customer accounts, and tracks customers' use of PG&E's existing translation services and translated materials provide in its customer call center and on its website. Currently, PG&E provides translated content in seven languages on the website and

³⁸ Language defined as "prevalent" is based on the following: (1) If the in-language population is more than 10,000 within a county, or (2) if the in-language population is more than five percent of the total county population, based on census data.

uses a top translation service provider in the industry, Language Line Services, to provide translation services in over 240 languages in the contact center.

In order to reach customers with limited English proficiency and mitigate for language access challenges, PG&E has translated key emergency preparedness and PSPS outreach and awareness materials in English, Spanish, Chinese, Tagalog, Vietnamese, Korean, and Russian and made them available on www.pge.com and at community events. During a PSPS event, PG&E will make translated notifications available to potentially impacted customers in the languages noted above. Data on the prevalent languages in affected areas will be used to determine the language used for outreach through social, broadcast, and print media. Any additional language needs can be met by calling PG&E's customer call center, which is equipped to translate messaging in over 240 languages.

In 2020, PG&E will enhance coordination with Community Based Organizations (CBOs) and multi-cultural media partners that have existing relationships and serve disadvantaged and/or hard to reach communities to provide in-language / translated education. The CBOs have established relationships and will ensure customers have a trusted-channel to get the information that they need. PG&E will continue to provide translated notifications during PSPS events, as well as translated outreach materials and emergency preparedness and PSPS-related content on PG&E's website. The approach to reach Limited English Proficiency (LEP) communities, could include paid and earned media, event outreach, social media, or reaching out to owners/property managers of migrant worker housing to identify opportunities for additional outreach and engagement.

Emergency Planning and Preparedness Initiatives

Below, PG&E describes the following emergency planning and preparedness-related initiatives, including the existing program and its expected evolution over the next 10 years.

1. Adequate and trained workforce for service restoration
2. Community outreach, public awareness, and communications efforts
3. Customer support in emergencies
4. Disaster and emergency preparedness plan
5. Preparedness and planning for service restoration
6. Protocols in place to learn from wildfire events

5.3.9.1 Adequate and Trained Workforce for Service Restoration

PG&E has a large workforce that is geographically distributed and can be moved across the territory as needed. PG&E has begun, and will continue to use, the relevant, rapid training approach to build an internal workforce that is in a steady state of readiness with the skills and abilities to react and respond to any incident within the service territory. As discussed in more detail above in Section 5.3.9, PG&E has Mutual Aid agreements that allow the flexibility to increase resources in response to events. Contractor and Mutual Aid support resources will be adequately trained in PSPS Restoration Overview prior to performing work in the field when utilized.

For the 2020 training plan, PG&E is updating the curriculum and exercises to reflect the lessons learned from actual 2019 events. Workforce skills/performance will be tracked and measured after each training course completion (including field exercises) via PG&E's internal Learning Management System to ensure continuous improvement in processes, skills and behaviors. Training curriculum is developed in alignment with SEMS, where appropriate. As new or emerging technologies are identified for use in the field, training will be developed to facilitate timely use in field operations. Restoration skills and abilities training will be delivered and measured in classroom, Web Based Training (WBT) and restoration field exercises throughout the service territory at a periodicity driven by performance and behavior. Training will be revised, updated and adjusted to reflect changes and updates in policy and/or processes as needed.

Progress Timeline

- 1. **Before the upcoming wildfire season:** PG&E will develop the exercise strategy and timeline described above, as well as deliver the updated TD 1464B-002 Public Safety Power Shutoff for Distribution and Transmission Electric Facilities training.
- 2. **Before the next annual update:** Before the next annual update, PG&E will complete PSPS OEC emergency planning exercises as scheduled.
- 3. **Within the next 3 years:** Continue to evaluate and update training needs for the service restoration workforce.
- 4. **Within the next 10 years:** Update training to align with changes in requirements, regulations or other guidance.

5.3.9.2 Community Outreach, Public Awareness, and Communications Efforts

Starting in 2018, PG&E began reaching out to customers and communities about its CWSP. This includes:

- Face to Face Interactions:
 - Hosting community open house events so local residents can learn more about CWSP.
 - Participating in face to face meetings with customers.
- Digital Engagement:
 - Hosting informational webinars for customers and/or organizations who are unable to attend a community open house event in person.
 - Developing and delivering additional video resources, including explainer videos that have been translated to American Sign Language (ASL) and other languages, further increasing PG&E’s ability to communicate to a larger group of customers.
 - Providing PSPS preparedness, safety resources and event-specific information on PG&E’s website.
- Direct Mail/Print Media Engagement¹:
 - Sending direct mail and emails to customers with information regarding PSPS preparedness resources and reminders to update contact information so PG&E can reach out to customers in advance of a public safety power outage.
 - Providing paid and unpaid advertising in print media.

In addition, PG&E has been meeting regularly with state agencies, counties, cities, tribes, first responders, other local emergency responders and community groups throughout its service area regarding CWSP to gather feedback and share system improvements made and planned to further reduce the risk of wildfire. In addition, PG&E conducts annual gas and electric safety training for first responders, including law enforcement, fire departments, and public works and transportation agencies. Moving forward, PG&E will continue to find new ways to engage state agencies, counties, cities, tribes, first responders, other local emergency responders and community groups. This outreach ensures that customers, communities and public safety agencies are aware of PG&E’s wildfire safety actions, potential impacts on their communities and steps they can take to prepare.

¹ See Table 30 Section 5-1 for details regarding PSPS and emergency preparedness media education campaigns.

5-240

PG&E will conduct listening sessions to gather feedback, as well as monitor comments received through regulatory proceeding, such as responses to PG&E's De-energization Event Reports. To assess the effectiveness of the customer outreach conducted, as more fully described in *Section 5.6.2.4 Customer, Agency and External Communications*, throughout the year, PG&E gathers and assesses both qualitative and quantitative data to evaluate customers' awareness, feedback and recall of PG&E outreach, including wildfire safety and preparedness. ~~This is done through statistically significant research studies, as well as surveys, customer feedback and input from CBOs, and by tracking customer engagement including web traffic, click-through-rates of advertisements and conversion rates / actions taken by customers as a result. PG&E will adjust as needed to ensure the effective use of available outreach channels.~~ This is done through multiple sources of direct customer feedback including, but not limited to: opinion surveys, interviews with CBOs, and tracking customer engagement through web traffic (e.g. click-through-rates of advertisements, conversion rates, etc.), and actions taken by customers as a result. PG&E will adjust as needed to ensure the effective use of available outreach channels. With customer surveys, PG&E will compare the responses of various groups (e.g. residential vs. non-residential). Where we have 95% confidence those differences in response are due to actual underlying differences and not chance, we will note those differences as being "statistically significant."

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E will implement its community outreach efforts as described above. Additionally, PG&E will continue to enhance its communications and engagement efforts with a focus on wildfire safety and preparedness for PSPS events. This includes increasing the number of open houses (approximately double the volume completed in 2019) and webinars hosted by PG&E for customers, maintaining strengthened website capabilities to withstand heightened traffic during a PSPS event, developing and delivering additional video resources, including explainer videos that have been translated to American Sign Language (ASL) and other languages, further increasing PG&E's ability to communicate to a larger group of customers, and continuing to work closely with state, county, city and tribal agency partners to improve coordination and begin implementing feedback through the activities described above.
2. **Before the next annual update:** PG&E will continue the outreach described above and will adjust communications channels and outreach approach based on the customers' channels of choice and lessons learned.
3. **Within the next 3 years:** PG&E will continue to adjust outreach and education to better address customer needs.
4. **Within the next 10 years:** PG&E will continue to assess its communications methods and adjust its focus areas for engagement, as appropriate.

5.3.9.3 Customer Support in Emergencies

In an effort to reduce the consequence of wildfires through multiple financial programs, PG&E will provide customer protections to eligible customers that are impacted by a state of emergency. The details of this program are more fully described in the introduction to Section 5.3.9.

Twelve months after each declared state of emergency (or at a time reasonably determined by the Governor’s Office of Emergency Services), as required by CPUC D.19-07-015 (OP 6), PG&E will submit a report to the CPUC that describes the consumer protections offered and outreach provided to customers, including relevant metrics. As a mechanism to assess program effectiveness, PG&E will leverage this report to identify customer adoption of the program’s offerings and may make recommendations for adjustments to the program and/or outreach based on customer utilization of the program. PG&E will submit its first post-emergency report by October 25, 2020³⁹ in response to California Governor Newsom’s declaration of a State of Emergency on October 25, 2019 for customers impacted by the Kincade Fire in Sonoma County.

If necessary, PG&E will re-prioritize spending and deployment of resources where there would be no negative impact on public or employee safety in order to conduct disaster recovery and extend consumer protections.

Progress Timeline

- 1. **Before the upcoming wildfire season:** Continue to implement PG&E’s Consumer Protections Program as described above.
- 2. **Before the next annual update:** Continue to offer the consumer protections described above. PG&E will file its first post-emergency report in October 2020.
- 3. **Within the next 3 years:** PG&E will make modifications to its consumer protection and customer support programs based on the outcomes from the post-emergency report(s) review, if new regulatory requirements are issued in alignment with the Consumer Protections Proceeding R. 18-03-011 or as otherwise needed.
- 4. **Within the next 10 years:** Continue to implement and update consumer protection programs to meet regulatory requirements and as needed to support PG&E’s customers.

³⁹ Or a date or as reasonably determined by the Governor’s Office of Emergency Services.

5.3.9.4 Disaster and Emergency Preparedness Plan

PG&E complies with CPUC Code 768.6 by a variety of methods. The CERP is drafted in accordance with GO 166. The CERP is considered an "all-hazards" reference, which is supplemented by numerous "Annex" documents that cover specific contingencies ranging from Wildfire, to Cyber Incidents, to Earthquakes. Each of these documents is reviewed and updated annually in accordance with the General Order. PG&E documents such compliance through an annual filing, which is submitted directly to the CPUC and is based on the previous year's performance as documented through an internal audit process.

Feedback from stakeholders has typically been obtained through Public Safety Specialist (PSS) teams from both the Gas and Electric divisions, who interact directly with partner agencies, particularly during emergencies. Direct feedback through visits by agency officials to PG&E's headquarters, which is required by CPUC Code and embraced by PG&E, has only partly materialized, for 2020, EP&R (All-Hazards Planning and Response) plans to meet directly with State and County Emergency Management Officials to obtain feedback and input into programs and processes. In addition, PG&E will be activating a managed email box that will allow external stakeholders to submit their feedback directly, without having to channel the information through a liaison. PG&E will also be visiting a minimum of 2 Mutual Aid Regional Advisory Council (MARAC) meetings, as well as participating in at least 2 emergency management industry conferences or trade shows, one of which will be the State CESA conference.

Progress Timeline

- 1. Before the upcoming wildfire season:** PG&E will continue to implement wildfire-centric planning and preparedness, as well as conduct employee and public safety agency outreach activities. EOC planning and internal training/exercise program will be developed to expand beyond current parameters. Existing employees will undergo additional focused training on PSPS, ICS, SEMS, and individual position-specific emergency roles prior to upcoming wildfire season. Enhanced awareness activities for all employees will be in progress and on-going. For PSPS responses, additional emergency roles will be added to the PG&E ICS organization.
- 2. Before the next annual update:** All applicable deliverables will be updated/published within specified timelines, including the Company Emergency Response Plan and all annexes. These documents are currently required to be updated annually, not later than June 30 for the CERP and September 30 for each of the Annexes. Development of partnerships with wildfire-specific public safety partner agencies expected to begin greater evolution. Partnerships with Operational Areas and Counties will demonstrate collaborations in emergency planning. Additional benchmarking of other utility practices in in relative planning and preparedness activities will have been achieved.
- 3. Within the next 3 years:** Long term development of plans and annexes, as well as partnerships with other utilities and government agencies, will have taken place. PG&E will collaborate in local Hazard Mitigation Planning with specific Operational Areas within the service territory. Expect development of cycliclarge-scale inter-agency exercise program.
- 4. Within the next 10 years:** The preceding priorities will have reached a state of maturity and routine cyclic maintenance of plans and strategies will be taking place. Robust emergency management plans and strategies are expected to be fully developed and ahead of established best practices in the industry. The PG&E Emergency Preparedness and Response Organization will be fully resourced.

5.3.9.5 Preparedness and Planning for Service Restoration

In preparation for the upcoming wildfire season, throughout the service territory, PG&E will conduct field exercises, classroom trainings and WBT to prepare utility personnel to restore services after emergencies. Utility Standard TD-1464B-002 Preventing and Mitigating Fires While Performing PG&E Work is incorporated into the training to ensure compliance. Beyond these approaches, PG&E will provide additional support such as personnel and other reasonable resources where needed based on the lessons learned from these exercises. During restoration exercises, areas will be utilizing the latest tools and resources available in order to prepare for the upcoming season.

Future exercises will increase in complexity and difficulty to strengthen PG&E's preparedness posture. Training curriculum is developed in alignment with the SEMS, where appropriate. Restoration skills and abilities training will be delivered and measured in classroom, WBT and restoration field exercises throughout the service territory at a periodicity driven by performance and behavior. Training will be revised, updated and adjusted to reflect changes in policy and/or processes as needed. See also Section 5.3.6.3, Personnel Work Procedures and Training in Conditions of Elevated Fire Risk and Section 5.3.6.4, Protocols for PSPS Re-Energization.

Progress Timeline

- 1. **Before the upcoming wildfire season:** Before the upcoming wildfire season, PG&E will deliver TD 1464B-002 training.
- 2. **Before the next annual update:** Before the next annual update, PG&E will complete all hazards approach emergency planning exercises.
- 3. **Within the next 3 years:** Continue to evaluate and update field exercise and classroom trainings to incorporate lessons learned and to address changing requirements and regulations.
- 4. **Within the next 10 years:** Continue to evaluate and update field exercise and classroom trainings to incorporate lessons learned and to address changing requirements and regulations.

5.3.9.6 Protocols in Place to Learn from Wildfire Events

Following major incidents or events that lead to an activation of the Company EOC, including major wildfire incidents and PSPS events, PG&E's routinely conducts After Action Reviews (AARs) to identify, collect and address lessons learned from such incidents and events. This process is outlined in the CERP per CPUC GO 166, "Standards for Operation, Reliability and Safety During Emergencies and Disasters."

Following an activation of the EOC, PG&E prepares an AAR, which generally involves the following process:

- Feedback from EOC staff who supported the activation is solicited and analyzed;
- An Improvement Plan is developed and disseminated to the appropriate stakeholders within the affected lines of business;
- Appropriate corrective actions determined, including reviewing emergency operations plans to determine whether modifications need to be made;
- Individual action items tracked as appropriate; and,
- Action item status reported monthly to internal corporate leadership

As applicable, such as in the Post-Event De-Energization Reports, PG&E also identifies and reports key lessons learned from PSPS events, which is an outcome from the AAR process.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E will implement the protocols described above as conditions warrant.
2. **Before the next annual update:** PG&E will implement the protocols described above as conditions warrant and incorporate lessons learned into the protocols.
3. **Within the next 3 years:** PG&E will evaluate and update protocols for learning from wildfire events.
4. **Within the next 10 years:** PG&E will continue to review and modify protocols for learning from wildfire events.

5.3.9.7 Other / Not Listed [Only if an Initiative Cannot Feasibly be Classified Within Those Listed Above]

5.3.9.7.1 Resource Sharing to Support Inspection Work and Other Aspects of the Wildfire Management Plan

PG&E inspection protocols currently utilize journeymen craft personnel (linemen, electrician, towermen) as the primary assessor, appropriate to the types of facilities being inspected or patrolled PG&E maintains a contractor workforce through its Contract Management office, ensuring that sufficient personnel are available for contingency operations. Additionally, PG&E manages its Mutual Assistance agreements with other utilities through the CUEA, WRMAA and the EEI, giving PG&E access to over 80% of the public utility industry across the United States and Canada. [In addition to contractor resources and Mutual Assistance agreements, PG&E owns and maintains aviation resources. The 2020 – 2022 aviation operations and maintenance expense forecast in Table 29, Section 7 was determined by forecasting total operation and maintenance expenses, less forecast chargebacks and forecast reimbursements from CAI FIRE for utilizing PG&E helicopters. See also Section 5.5, Planning for Workforce and Other Limited Resources.](#)

Progress Timeline

1. **Before the upcoming wildfire season:** If additional resources are needed to support inspection work or the WMP, reach out to resources via the Contract Management Office or Mutual Assistance agreements listed above.
2. **Before the next annual update:** As needed, identify additional resources as described above. Continue to identify additional sources of qualified resources.
3. **Within the next 3 years:** Continually maintain and update resource sharing agreements to increase the pool of available, qualified resources.
4. **Within the next 10 years:** Continually maintain and update resource sharing agreements to increase the pool of available, qualified resources.

5.3.10 Stakeholder Cooperation and Community Engagement

Description of Programs to Reduce Ignition Probability and Wildfire Consequence

For each of the below initiatives, provide a detailed description and approximate timeline of each, whether already implemented or planned, to minimize the risk of its equipment or facilities causing wildfires. Include a description of the utility's initiatives, the utility's rationale behind each of the elements of the initiatives, the utility's prioritization approach/methodology to determine spending and deployment of human and other resources, how the utility will conduct audits or other quality checks on each initiative, how the utility plans to demonstrate over time whether each component of the initiatives is effective and, if not, how the utility plans to evolve each component to ensure effective spend of ratepayer funds.

Include descriptions across each of the following initiatives. Input the following initiative names into a spreadsheet formatted according to the template below and input information for each cell in the row.

- 1. Community engagement
- 2. Cooperation and best practice sharing with agencies outside CA
- 3. Cooperation with suppression agencies
- 4. Forest service and fuel reduction cooperation and joint roadmap
- 5. Other / not listed [only if an initiative cannot feasibly be classified within those listed above]

The list provided is non-exhaustive and utilities shall add additional initiatives to this table as their individual programs are designed and structured. Do not create a new initiative if the utility's initiatives can be classified under a provided initiative.

For each of the above initiatives, describe the utility's current program and provide an explanation of how the utility expects to evolve the utility's program over each of the following time periods:

- 1. Before the upcoming wildfire season,
- 2. Before the next annual update,
- 3. Within the next 3 years, and
- 4. Within the next 10 years.

See Attachment 1, Table 29 for the details and data associated with the initiatives discussed in this section.

5.3.10.1 Community Engagement

The following describes PG&E's community engagement related to PG&E's wildfire safety programs, including System Hardening, Enhanced Vegetation Management, and the system inspections, which support wildfire mitigation activities. Community outreach related to emergency preparedness and PSPS is more fully described in Sections 5.3.9.2 Community Outreach, Public Awareness, and Communications Efforts and 5.6.2.3 PSPS Customer, Agency and External Communications, respectively.

PG&E conducts community outreach to educate customers/property owners on the details of PG&E's wildfire safety programs and the potential need for their participation to reduce wildfire risks in their communities. PG&E also conducts outreach to cities, counties, tribes and other emergency response agencies to share information and work together on a plan for the wildfire safety work. PG&E also maintains an open channel of communication with customers and communities who proactively reach out to PG&E when identifying safety risks related to these programs.

To identify and implement efficient and appropriate customer and community communications, PG&E assesses the anticipated program impacts related to planned road closures, property access needs, tree removal, helicopter operations, among others. To set expectations with customers and with the goal of limiting work refusals or access issues, PG&E uses various communication methods, such as letters, postcards, text messages, emails, and automated calls through Interactive Voice Recordings (IVRs). PG&E will provide translated outreach in alignment with the language access and translations strategy described in Section 5.3.9.

Outreach includes broad communications about PG&E wildfire safety-related work scope in neighborhoods, cities, and counties, as well as direct communications to customers/property owners who may be impacted by PG&E employees and contractors requiring access to their sites to conduct the necessary safety-related wildfire prevention work.

PG&E also responds to issues raised by customers/property owners including general access issues (e.g., locked gate), or sensitive access issues (e.g., upset individual). In some cases, properties requiring access/work may be occupied by a customer of record that differs from the property owner, in which case PG&E will engage with both. PG&E addresses these issues by contacting the customers/property owners directly to understand their concerns and to develop a mutual solution that allows access to complete the relevant wildfire safety work.

In certain instances, such as in the system inspections program, if PG&E is unable to coordinate access to its facilities with the customer/property owner, PG&E may leverage their authorization via Rule 11 to turn off customers' power to complete safety-related work to inspect or repair facilities. PG&E will only consider this avenue to ensure safety related work can be completed and will work to limit such instances. Customers will receive communication from PG&E if this action must be implemented.

PG&E works with customers to develop solutions to resolve property owner non-compliance issues (e.g., property access or work refusals) and escalated CPUC complaints by landowners that are impacted by PG&E's CWSP programs, including EVM, system hardening, and system inspections. PG&E will work to minimize complaints and non-compliance through the outreach described above.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E will continue to conduct customer outreach and will continue to respond to customer-related access issues as described above.
2. **Before the next annual update:** PG&E will evaluate proactive outreach and reactive communications to identify any necessary adjustments to the outreach based on lessons learned.
3. **Within the next 3 years:** PG&E will continue to evaluate and adjust its outreach programs, focusing on building relationships with property owners where PG&E assets are located.
4. **Within the next 10 years:** PG&E will modify the community outreach programs to keep pace with the evolving WMP.

5.3.10.2 Cooperation and Best Practice Sharing With Agencies Outside CA

PG&E engages with parties both inside and outside the state of California, as discussed in Section 5.3.7.2, to share practices, tools and approaches on numerous topics, including wildfire risk reduction. PG&E has benchmarked substantially with utilities in Australia who have had meaningful experiences and learnings from that country's wildfire / bushfire challenges. For example, the Rapid Earth Fault Current Limiter (REFCL) technology that PG&E is piloting (see Section 5.1.D.3.6) was developed in Australia.

PG&E shares best practices and benchmarks with other utilities throughout the United States as well, particularly through industry associations like the Edison Electric Institute (EEI) which, as an example, has been facilitating a series of engagements regarding "Wildfire Technology" exploration, sharing and discussion.

Beyond the utility industry PG&E engages with other entities to identify synergies and learnings for addressing wildfire risks. As noted in Section 5.3.10.4, PG&E has been deeply engaged with Federal Land Owners on how to partner on mitigating wildfire risks on those lands. PG&E is also partnering with educational institutions and firms from across the country to explore technologies or other tools (like egress analysis) that may contribute to reducing wildfire risk. Examples include the Distribution Fault Anticipation Technology (Section 5.3.2.2.4) and Fault Signature (Section 5.3.2.2.7) technology projects.

Progress Timeline

- 1. *Before the upcoming wildfire season:* Continue to engage with partners from inside and outside California to share PG&E's experiences and identify tools, technologies or other best practices that can contribute to reducing wildfire risk.
- 2. *Before the next annual update:* Same as above.
- 3. *Within the next 3 years:* Same as above.
- 4. *Within the next 10 years:* Same as above.

5.3.10.3 Cooperation With Suppression Agencies

Public Safety Specialist (PSS)

The PSS team maintains established relationships with agency partners to support emergency planning activities and information sharing during emergencies. The PSS team serves as the PG&E Agency Representative to coordinate and integrate PG&E's response with the Agency Having Jurisdiction (AHJ) over an active incident. The real-time intelligence sharing informs PG&E's tactical plans and the deployment of additional resources to support fire mitigation and asset protection activities.

After the PSS integrates into the local incident command structure they facilitate communications between the community first responders, PG&E Emergency Operations Center (EOC) staff, WSOC personnel and PG&E first responders. In this respect, the PSS team serves as liaison officers (LNO) and PG&E Agency Representatives, as well as support for other lines of business.

Another key focus area for the PSS team is to act as a single point of contact during large events (e.g., PSPS event). During these events, the PSS will report into PG&E's EOC Liaison Organization. The PSS serves as the primary Point of Contact for informational inquiries to all local agency partners.

The PSS team plays a key role during emergency planning activities and public safety agency engagement as outlined in Section 5.3.9.4, Coordination with Public Safety Partners. The following activities demonstrate many of the PSS team's coordination efforts with PG&E's internal teams and agency partners.

Key Projects

- Coordinate vegetation management activities between CAL FIRE and PG&E where feasible
- TD 1464s, Fire Prevention and Mitigation for PG&E Work, Training
- Satellite information sharing
- Camera siting input
- Weather station siting input
- System Hardening and PSSP Mitigation Plans

Public Partner Outreach

- CWSP Open Houses
- PSPS Workshops
- Public Safety Liaison Meetings – 49 CFR
- First Responder Workshops – 49 CFR Gas and Electric Training

- Triennial Regulatory Workshops – CPUC - Training on gas system
- Annual Contingency Plan Meeting – CPUC - Gas line emergency contingency planning
- Live Fire and Gas Release Training

Progress Timeline

1. **Before the upcoming wildfire season:** Continue cooperation and coordinate with suppression agencies as described above.
2. **Before the next annual update:** Continue cooperation with suppression agencies and identify and implement new projects or other efforts as needed to enhance coordination.
3. **Within the next 3 years:** Evaluate and modify initiatives to address current needs with agency partners.
4. **Within the next 10 years:** Evaluate and modify initiatives to address current needs with agency partners.

5.3.10.4 Forest Service and Fuel Reduction Cooperation and Joint Roadmap

PG&E has had long-running partnerships with the United States Forest Service (USFS) and other federal landowners upon whose land PG&E assets are located. In some cases, the PG&E assets on those lands actually pre-date the existence of the federal mandate establishing the forest, park or entity that now manages the land. Nonetheless, those relationships have evolved over the last decade, and more aggressively in recent years, due to a number of factors including the California Drought and Bark Beetle infestation and the rapidly evolving wildfire risk facing these lands. Both parties have recognized the need for faster action to support wildfire risk mitigation. Through this partnership, PG&E and Region 5 of the USFS were able to successfully complete the reissuance and consolidation of hundreds of historically individual and unique utility permits on National Forest System Lands. Now the forests are able to monitor and renew utility permits by providing one permit and one easement per forest.

These updated permits are accompanied by a Programmatic Operations and Maintenance Plan (O&M Plan), that describes the utility's facilities and activities on USFS land and establishes the activity review process, which defines the environmental review and protection process and establishes communication and monitoring protocols between PG&E and the Forest. The O&M Plan has successfully reduced the amount of time staff spends reviewing and processing approvals for routine operation and maintenance activities. Where before it could have taken 6-12 months to obtain approval to address a potential wildfire hazard, it now takes 5 to 15 days to obtain approval to move forward with the activity. Therefore, the O&M Plan aids with maintaining PG&E's facilities in a safe and reliable manner as it lays out the when, where, and how PG&E can conduct vital work, including vegetation management around utility rights-of-way. This streamlined process helps assure electric facilities and rights-of-way are regularly maintained, thereby reducing fire hazards.

Building off the O&M Plan, in 2019 PG&E implemented a cost recovery program with the USFS that provided funding to four forests to complete fuels reduction on 3,500 acres of USFS land outside of PG&E's right of ways. This allows the forests an avenue to complete additional fuels reduction work that could impact PG&E assets within areas that PG&E does not have land rights or authorization to complete key fuel reduction activities (but the forest does have such rights).

In 2020, PG&E plans to continue and refine the cost recovery program with USFS, with additional funding available for all 11 forests within PG&E's service territory. Given the successes from 2019 we expect that all 11 forest will provide proposals for 2020. PG&E anticipates facilitating a request for proposal process in the first quarter of 2020 and starting to award funds in the 2nd quarter. Depending on the 2020 experience and learnings from this process PG&E is also exploring expanding this program to other Federal (or even State) Agencies, which could, conceivably include the National Park Service, BLM, and/or State Parks.

While PG&E staff members are in near-daily, operational contact and communication with USFS staff, PG&E leadership also meets with USFS leadership on a bi-annual basis to explore opportunities where we can continue to collaborate to reduce wildfire risk within California. Topics that have been or will be explored through these meetings

are clarifying the process for the disposition of felled trees (e.g., timber sale, lop and scatter, chipping), funding Forest Service positions to assist with the review of PG&E work requests, and the Integrated Vegetation Management (IVM) approach that would allow the use of Forest-approved herbicides to control utility incompatible vegetation while seeking to encourage a low-growing stable plant community around powerlines.

PG&E also has activities underway with other Federal and State landowners besides the USFS. Some highlights include:

- **California State Parks:** PG&E is finalizing a process agreement that allows for streamlining utility work throughout California State Parks across the entire service territory. This agreement would allow for non-invasive and emergency work to proceed without delay and minor wildfire fuels reduction work to proceed after a two-week notification process. (Major wildfire work would follow the existing, permitting requirements and process flow.) This process agreement is expected to go to the California State Parks executive committee for approval in early 2020.
- **Bureau of Land Management (BLM):** Building on ongoing efforts to reduce the threat of wildfires through active management, the BLM California State Office worked with SCE and PG&E to issue a new policy to limit fire risk from power lines crossing BLM-managed public lands. The new policy was enacted May 20, 2019 and extended by one year, through 2020, allows PG&E to facilitate and expedite O&M activities necessary to reduce the risk of wildfire by conducting the activities without prior authorization. Additionally, PG&E continues to work with the BLM Bakersfield Field Office on a Programmatic Right of Way renewal process and O&M Plan which may be used as a template to streamline process with other field offices in the future.
- **National Park Service (NPS):** In 2019, PG&E worked with the NPS Pacific West Region to put establish eight park-specific 1-Year Special Use Permits for 2020 which will allow PG&E to expedite critical, routine O&M activity within NPS-managed land. The permits require park approval within 15 days for most routine utility O&M activity and will also authorize drone usage within parks for utility purposes like asset inspections.

Progress Timeline

1. **Before the upcoming wildfire season:** PG&E anticipates funding USFS forests for fuel reduction projects outside of PG&E rights-of-way through the fuel reduction cost recovery program.
2. **Before the next annual update:** PG&E will be working with USFS leadership to incorporate the lessons learned from 2019 and 2020 into continued efficient use of the O&M plan to enable critical utility wildfire risk reduction work and exploring continued partnership opportunities to reduce wildfire risk.
3. **Within the next 3 years:** PG&E will be leveraging the progress made with USFS to develop improved processes and partnership with other Federal and/or State land owners / managers to streamline work approval processes (similar to the USFS O&M Plan) and partner on wildfire risk reduction work.
4. **Within the next 10 years:** PG&E anticipates continuing to incorporate learnings and partnering with Federal and State land-owners/managers to further enhance the efficiency and effectiveness of wildfire risk reduction activities that can be taken by any party on these lands.

5.3.11 Definitions of Initiative Activities by Category

These definitions were provided by the CPUC WSD for the purposes of the utilities in categorizing wildfire mitigation activities into initiatives in Section 5.3. These initiative definitions have been reproduced here for ease of cross-referencing the CPUC WSD's organizational guidance for the preceding section of the WMP.

Category	Initiative	Definitions
A. Risk mapping and simulation	A summarized risk map that shows the overall ignition probability and estimated wildfire consequence along the electric lines and equipment	Development and use of tools and processes to develop and update risk map and simulations and to estimate risk reduction potential of initiatives for a given portion of the grid (or more granularly, e.g., circuit, span, or asset). May include verification efforts, independent assessment by experts, and updates.
	Climate-driven risk map and modelling based on various relevant weather scenarios	Development and use of tools and processes to estimate incremental risk of foreseeable climate scenarios, such as drought, across a given portion of the grid (or more granularly, e.g., circuit, span, or asset). May include verification efforts, independent assessment by experts, and updates.
	Ignition probability mapping showing the probability of ignition along the electric lines and equipment	Development and use of tools and processes to assess the risk of ignition across regions of the grid (or more granularly, e.g., circuits, spans, or assets).
	Initiative mapping and estimation of wildfire and PSPS risk-reduction impact	Development of a tool to estimate the risk reduction efficacy (for both wildfire and PSPS risk) and risk-spend efficiency of various initiatives.
	Match drop simulations showing the potential wildfire consequence of ignitions that occur along the electric lines and equipment	Development and use of tools and processes to assess the impact of potential ignition and risk to communities (e.g., in terms of potential fatalities, structures burned, monetary damages, area burned, impact on air quality and greenhouse gas, or GHG, reduction goals, etc.).
B. Situational awareness and forecasting	Advanced weather monitoring and weather stations	Purchase, installation, maintenance, and operation of weather stations. Collection, recording, and analysis of weather data from weather stations and from external sources.
	Continuous monitoring sensors	Installation, maintenance, and monitoring of sensors and sensorized equipment used to monitor the condition of electric lines and equipment.
	Fault indicators for detecting faults on electric lines and equipment	Installation and maintenance of fault indicators.
	Forecast of a fire risk index, fire potential index, or similar	Index that uses a combination of weather parameters (such as wind speed, humidity, and temperature), vegetation and/or fuel conditions, and other factors to judge current fire risk and to create a forecast indicative of fire risk. A sufficiently granular index shall inform operational decision-making.

Category	Initiative	Definitions
	Personnel monitoring areas of electric lines and equipment in elevated fire risk conditions	Personnel position within utility service territory to monitor system conditions and weather on site. Field observations shall inform operational decisions.
	Weather forecasting and estimating impacts on electric lines and equipment	Development methodology for forecast of weather conditions relevant to utility operations, forecasting weather conditions and conducting analysis to incorporate into utility decision-making, learning and updates to reduce false positives and false negatives of forecast PSPS conditions.
C. Grid design and system hardening	Capacitor maintenance and replacement program	Remediation, adjustments, or installations of new equipment to improve or replace existing capacitor equipment.
	Circuit breaker maintenance and installation to de-energize lines upon detecting a fault	Remediation, adjustments, or installations of new equipment to improve or replace existing fast switching circuit breaker equipment to improve the ability to protect electrical circuits from damage caused by overload of electricity or short circuit.
	Covered conductor installation	Installation of covered or insulated conductors to replace standard bare or unprotected conductors (defined in accordance with GO 95 as supply conductors, including but not limited to lead wires, not enclosed in a grounded metal pole or not covered by: a "suitable protective covering" (in accordance with Rule 22.8), grounded metal conduit, or grounded metal sheath or shield). In accordance with GO 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other non-conductive material having the electrical insulating efficiency (12KV/in. dry) and impact strength (20lb.-lbs) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D.

Category	Initiative	Definitions
	Covered conductor maintenance	Remediation and adjustments to installed covered or insulated conductors. In accordance with GO 95, conductor is defined as a material suitable for: (1) carrying electric current, usually in the form of a wire, cable or bus bar, or (2) transmitting light in the case of fiber optics; insulated conductors as those which are surrounded by an insulating material (in accordance with Rule 21.6), the dielectric strength of which is sufficient to withstand the maximum difference of potential at normal operating voltages of the circuit without breakdown or puncture; and suitable protective covering as a covering of wood or other non-conductive material having the electrical insulating efficiency (12kV/in. dry) and impact strength (20ft.-lbs) of 1.5 inches of redwood or other material meeting the requirements of Rule 22.8-A, 22.8-B, 22.8-C or 22.8-D.
	Crossarm maintenance, repair, and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing crossarms, defined as horizontal support attached to poles or structures generally at right angles to the conductor supported in accordance with GO 95.
	Distribution pole replacement and reinforcement, including with composite poles	Remediation, adjustments, or installations of new equipment to improve or replace existing distribution poles (i.e., those supporting lines under 65kV), including with equipment such as composite poles manufactured with materials reduce ignition probability by increasing pole lifespan and resilience against failure from object contact and other events.
	Expulsion fuse replacement	Installations of new and CAL FIRE-approved power fuses to replace existing expulsion fuse equipment.
	Grid topology improvements to mitigate or reduce PSPS events	Plan to support and actions taken to mitigate or reduce PSPS events in terms of geographic scope and number of customers affected, such as installation and operation of electrical equipment to sectionalize or island portions of the grid, microgrids, or local generation.
	Installation of system automation equipment	Installation of electric equipment that increases the ability of the utility to automate system operation and monitoring, including equipment that can be adjusted remotely such as automatic reclosers (switching devices designed to detect and interrupt momentary faults that can reclose automatically and detect if a fault remains, remaining open if so).
	Maintenance, repair, and replacement of connectors, including hotline clamps	Remediation, adjustments, or installations of new equipment to improve or replace

Category	Initiative	Definitions
		existing connector equipment, such as hotline clamps.
	Mitigation of impact on customers and other residents affected during PSPS event	Actions taken to improve access to electricity for customers and other residents during PSPS events, such as installation and operation of local generation equipment (at the community, household, or other level).
	Other corrective action	Other maintenance, repair, or replacement of utility equipment and structures so that they function properly and safely, including remediation activities (such as insulator washing) of other electric equipment deficiencies that may increase ignition probability due to potential equipment failure or other drivers.
	Pole loading infrastructure hardening and replacement program based on pole loading assessment program	Actions taken to remediate, adjust, or install replacement equipment for poles that the utility has identified as failing to meet safety factor requirements in accordance with GO 95 or additional utility standards in the utility's pole loading assessment program.
	Transformers maintenance and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing transformer equipment.
	Transmission tower maintenance and replacement	Remediation, adjustments, or installations of new equipment to improve or replace existing transmission towers (e.g., structures such as lattice steel towers or tubular steel poles that support lines at or above 65kV).
	Undergrounding of electric lines and/or equipment	Actions taken to convert overhead electric lines and/or equipment to underground electric lines and/or equipment (i.e., located underground and in accordance with GO 128).
	Updates to grid topology to minimize risk of ignition in HFTDs	Changes in the plan, installation, construction, removal, and/or undergrounding to minimize the risk of ignition due to the design, location, or configuration of utility electric equipment in HFTDs.
D. Asset management and inspections	Detailed inspections of distribution electric lines and equipment	In accordance with GO 165, careful visual inspections of overhead electric distribution lines and equipment where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.
	Detailed inspections of transmission electric lines and equipment	Careful visual inspections of overhead electric transmission lines and equipment where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and

Category	Initiative	Definitions
		<i>the condition of each rated and recorded.</i>
	<i>Improvement of inspections</i>	<i>Identifying and addressing deficiencies in inspections protocols and implementation by improving training and the evaluation of inspections.</i>
	<i>Infrared inspections of distribution electric lines and equipment</i>	<i>Inspections of overhead electric distribution lines, equipment, and right-of-way using infrared (heat-sensing) technology and cameras that can identify "hot spots", or conditions that indicate deterioration or potential equipment failures, of electrical equipment.</i>
	<i>Infrared inspections of transmission electric lines and equipment</i>	<i>Inspections of overhead electric transmission lines, equipment, and right-of-way using infrared (heat-sensing) technology and cameras that can identify "hot spots", or conditions that indicate deterioration or potential equipment failures, of electrical equipment.</i>
	<i>Intrusive pole inspections</i>	<i>In accordance with GO 165, intrusive inspections involve movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading.</i>
	<i>LIDAR inspections of distribution electric lines and equipment</i>	<i>Inspections of overhead electric transmission lines, equipment, and right-of-way using LIDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).</i>
	<i>LIDAR inspections of transmission electric lines and equipment</i>	<i>Inspections of overhead electric distribution lines, equipment, and right-of-way using LIDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).</i>
	<i>Other discretionary inspection of distribution electric lines and equipment, beyond inspections mandated by rules and regulations</i>	<i>Inspections of overhead electric transmission lines, equipment, and right-of-way that exceed or otherwise go beyond those mandated by rules and regulations, including GO 165, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.</i>
	<i>Other discretionary inspection of transmission electric lines and equipment, beyond inspections mandated by rules and regulations</i>	<i>Inspections of overhead electric distribution lines, equipment, and right-of-way that exceed or otherwise go beyond those mandated by rules and regulations, including GO 165, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.</i>

Category	Initiative	Definitions
	<i>Patrol inspections of distribution electric lines and equipment</i>	<i>In accordance with GO 165, simple visual inspections of overhead electric distribution lines and equipment that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.</i>
	<i>Patrol inspections of transmission electric lines and equipment</i>	<i>Simple visual inspections of overhead electric transmission lines and equipment that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.</i>
	<i>Pole loading assessment program to determine safety factor</i>	<i>Calculations to determine whether a pole meets pole loading safety factor requirements of GO 95, including planning and information collection needed to support said calculations. Calculations shall consider many factors including the size, location, and type of pole; types of attachments; length of conductors attached; and number and design of supporting guys, per D.15-11-021.</i>
	<i>Quality assurance / quality control of inspections</i>	<i>Establishment and function of audit process to manage and confirm work completed by employees or subcontractors, including packaging QA/QC information for input to decision-making and related integrated workforce management processes.</i>
	<i>Substation inspections</i>	<i>In accordance with GO 175, inspection of substations performed by qualified persons and according to the frequency established by the utility, including record-keeping.</i>
E. Vegetation management and inspection	<i>Additional efforts to manage community and environmental impacts</i>	<i>Plan and execution of strategy to mitigate negative impacts from utility vegetation management to local communities and the environment, such as coordination with communities to plan and execute vegetation management work or promotion of fire-resistant planting practices</i>
	<i>Detailed inspections of vegetation around distribution electric lines and equipment</i>	<i>Careful visual inspections of vegetation around the right-of-way, where individual trees are carefully examined, visually, and the condition of each rated and recorded.</i>
	<i>Detailed inspections of vegetation around transmission electric lines and equipment</i>	<i>Careful visual inspections of vegetation around the right-of-way, where individual trees are carefully examined, visually, and the condition of each rated and recorded.</i>
	<i>Emergency response vegetation management due to red flag warning or other urgent conditions</i>	<i>Plan and execution of vegetation management activities, such as trimming or removal, executed based upon and in advance of forecast weather conditions that indicate high fire threat in terms of ignition probability and wildfire consequence.</i>
	<i>Fuel management and reduction of "slash" from vegetation management activities</i>	<i>Plan and execution of fuel management activities that reduce the availability of fuel in proximity to potential sources of ignition, including both reduction or adjustment of live fuel (in terms of species or otherwise) and of</i>

Category	Initiative	Definitions
		dead fuel, including "slash" from vegetation
		management activities that produce vegetation material such as branch trimmings and felled trees.
	Improvement of inspections	Identifying and addressing deficiencies in inspections protocols and implementation by improving training and the evaluation of inspectors.
	LIDAR inspections of vegetation around distribution electric lines and equipment	Inspections of right-of-way using LIDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).
	LIDAR inspections of vegetation around transmission electric lines and equipment	Inspections of right-of-way using LIDAR (Light Detection and Ranging, a remote sensing method that uses light in the form of a pulsed laser to measure variable distances).
	Other discretionary inspections of vegetation around distribution electric lines and equipment	Inspections of rights-of-way and adjacent vegetation that may be hazardous, which exceeds or otherwise go beyond those mandated by rules and regulations, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.
	Other discretionary inspections of vegetation around transmission electric lines and equipment	Inspections of rights-of-way and adjacent vegetation that may be hazardous, which exceeds or otherwise go beyond those mandated by rules and regulations, in terms of frequency, inspection checklist requirements or detail, analysis of and response to problems identified, or other aspects of inspection or records kept.
	Patrol inspections of vegetation around distribution electric lines and equipment	Visual inspections of vegetation along rights-of-way that is designed to identify obvious hazards. Patrol inspections may be carried out in the course of other company business.
	Patrol inspections of vegetation around transmission electric lines and equipment	Visual inspections of vegetation along rights-of-way that is designed to identify obvious hazards. Patrol inspections may be carried out in the course of other company business.
	Quality assurance / quality control of vegetation inspections	Establishment and function of audit process to manage and confirm work completed by employees or subcontractors, including packaging QA/QC information for input to decision-making and related integrated workforce management processes.
	Recruiting and training of vegetation management personnel	Programs to ensure that the utility is able to identify and hire qualified vegetation management personnel and to ensure that both full-time employees and contractors tasked with vegetation management responsibilities are adequately trained to

Category	Initiative	Definitions
		<i>perform vegetation management work, according to the utility's wildfire mitigation plan, in addition to rules and regulations for safety.</i>
	<i>Remediation of at-risk species</i>	<i>Actions taken to reduce the ignition probability and wildfire consequence attributable to at-risk vegetation species, such as trimming, removal, and replacement.</i>
	<i>Removal and remediation of trees with strike potential to electric lines and Equipment</i>	<i>Actions taken to remove or otherwise remediate trees that could potentially strike electrical equipment, if adverse events such as failure at the ground-level of the tree or branch breakout within the canopy of the tree, occur.</i>
	<i>Substation inspection</i>	<i>Inspection of vegetation surrounding substations, performed by qualified persons and according to the frequency established by the utility, including record-keeping.</i>
	<i>Substation vegetation management</i>	<i>Based on location and risk to substation equipment only, actions taken to reduce the ignition probability and wildfire consequence attributable to contact from vegetation to substation equipment.</i>
	<i>Vegetation inventory system</i>	<i>Inputs, operation, and support for centralized inventory of vegetation clearances updated based upon inspection results, including (1) inventory of species, (2) forecasting of growth, (3) forecasting of when growth threatens minimum right-of-way clearances ("grow-in" risk) or creates fall-into-in risk.</i>
	<i>Vegetation management to achieve clearances around electric lines and equipment</i>	<i>Actions taken to ensure that vegetation does not encroach upon the minimum clearances set forth in Table 1 of GO 95, measured between line conductors and vegetation, such as trimming adjacent or overhanging tree limbs.</i>
<i>F. Grid operations and protocols</i>	<i>Automatic recloser operations</i>	<i>Designing and executing protocols to deactivate automatic reclosers based on local conditions for ignition probability and wildfire consequence.</i>
	<i>Crew-accompanying ignition prevention and suppression resources and services</i>	<i>Those firefighting staff and equipment (such as fire suppression engines and trailers, firefighting hose, valves, and water) that are deployed with construction crews and other electric workers to provide site-specific fire prevention and ignition mitigation during on-site work.</i>
	<i>Personnel work procedures and training in conditions of elevated fire risk</i>	<i>Work activity guidelines that designate what type of work can be performed during operating conditions of different levels of wildfire risk. Training for personnel on these guidelines and the procedures they prescribe, from normal operating procedures</i>

Category	Initiative	Definitions
		to increased mitigation measures to constraints on work performed.
	Protocols for PSPS re-energization	Designing and executing procedures that accelerate the restoration of electric service in areas that were de-energized, while maintaining safety and reliability standards.
	PSPS events and mitigation of PSPS impacts	Designing, executing, and improving upon protocols to conduct PSPS events, including development of advanced methodologies to determine when to use PSPS, and to mitigate the impact of PSPS events on affected customers and local residents.
	Stationed and on-call ignition prevention and suppression resources and services	Firefighting staff and equipment (such as fire suppression engines and trailers, firefighting hose, valves, firefighting foam, chemical extinguishing agent, and water) stationed at utility facilities and/or standing by to respond to calls for fire suppression assistance.
G. Data governance	Centralized repository for data	Designing, maintaining, hosting, and upgrading a platform that supports storage, processing, and utilization of all utility proprietary data and data compiled by the utility from other sources.
	Collaborative research on utility ignition and/or wildfire	Developing and executing research work on utility ignition and/or wildfire topics in collaboration with other non-utility partners, such as academic institutions and research groups, to include data-sharing and funding as applicable.
	Documentation and disclosure of wildfire-related data and algorithms	Design and execution of processes to document and disclose wildfire-related data and algorithms to accord with rules and regulations, including use of scenarios for forecasting and stress testing.
	Tracking and analysis of near miss data	Tools and procedures to monitor, record, and conduct analysis of data on near miss events.
H. Resource allocation methodology	Allocation methodology development and application	Development of prioritization methodology for human and financial resources, including application of said methodology to utility decision-making.
	Risk reduction scenario development and analysis	Development of modelling capabilities for different risk reduction scenarios based on wildfire mitigation initiative implementation; analysis and application to utility decision-making.
	Risk spend efficiency analysis	Tools, procedures, and expertise to support analysis of wildfire mitigation initiative risk-spend efficiency, in terms of MAVF and/or MARS methodologies.
I. Emergency planning and preparedness	Adequate and trained workforce for service restoration	Actions taken to identify, hire, retain, and train qualified workforce to conduct service restoration in response to

Category	Initiative	Definitions
		emergencies, including short-term contracting strategy and implementation.
	Community outreach, public awareness, and communications efforts	Actions to identify and contact key community stakeholders; increase public awareness of emergency planning and preparedness information; and design, translate, distribute, and evaluate effectiveness of communications taken before, during, and after a wildfire, including Access and Functional Needs populations and Limited English Proficiency populations in particular.
	Customer support in emergencies	Resources dedicated to customer support during emergencies, such as website pages and other digital resources, dedicated phone lines, etc.
	Disaster and emergency preparedness plan	Development of plan to deploy resources according to prioritization methodology for disaster and emergency preparedness of utility and within utility service territory (such as considerations for critical facilities and infrastructure), including strategy for collaboration with Public Safety Partners and communities.
	Preparedness and planning for service restoration	Development of plans to prepare the utility to restore service after emergencies, such as developing employee and staff trainings, and to conduct inspections and remediation necessary to re-energize lines and restore service to customers.
	Protocols in place to learn from wildfire events	Tools and procedures to monitor effectiveness of strategy and actions taken to prepare for emergencies and of strategy and actions taken during and after emergencies, including based on an accounting of the outcomes of wildfire events.
J. Stakeholder cooperation and community engagement	Community engagement	Strategy and actions taken to identify and contact key community stakeholders; increase public awareness and support of utility wildfire mitigation activity; and design, translate, distribute, and evaluate effectiveness of related communications. Includes specific strategies and actions taken to address concerns and serve needs of Access and Functional Needs populations and Limited English Proficiency populations in particular.
	Cooperation and best practice sharing with agencies outside CA	Strategy and actions taken to engage with agencies outside of California to exchange best practices both for utility wildfire mitigation and for stakeholder cooperation to mitigate and respond to wildfires.

Category	Initiative	Definitions
	Cooperation with suppression agencies	Coordination with CAL FIRE, federal fire authorities, county fire authorities, and local fire authorities to support planning and operations, including support of aerial and ground firefighting in real-time, including information-sharing, dispatch of resources, and dedicated staff.
	Forest service and fuel reduction cooperation and joint roadmap	Strategy and actions taken to engage with local, state, and federal entities responsible for or participating in forest management and fuel reduction activities; and design utility cooperation strategy and joint stakeholder roadmap (plan for coordinating stakeholder efforts for forest management and fuel reduction activities).

5.4 Methodology for Enterprise-Wide Safety Risk and Wildfire-Related Risk Assessment

Describe methodology for identifying and evaluating enterprise wide safety risk and wildfire related risk, and how that methodology is consistent with the methodology used by other electric utilities or electrical corporations. If the risk identification and evaluation methodology is different, the utility shall explain why in this section.

In D.18-12-014, the CPUC approved a Settlement Agreement, to which PG&E and the other California utilities were Settling Parties. The settlement agreement established steps required for a quantitative risk-based decision-making framework. Appendix A to the S-MAP settlement agreement is a list of 3 steps – with 25 individual elements divided among the steps - related to identifying and calculating risk factors. The key steps for calculating risk are shown in Table PG&E 5-4 below. PG&E’s method for evaluating safety risk and wildfire risk is consistent the requirements of the S-MAP settlement agreement and, therefore, consistent with the other electric utilities

TABLE PG&E-5-4: PG&E'S METHOD FOR COMPLYING WITH THE S-MAP SETTLEMENT AGREEMENT⁴⁰

S-MAP SA Step	Description	PG&E Implementation
1A	Build a Multi-Attribute Value Function (MAVF)	PG&E developed a MAVF that adheres to the set of principles in this Step. The MAVF is described in Section 4.2.
1B	Risk Identification and Definition	PG&E maintains an event-based enterprise risk register (ERR) and works with its lines of business on a regular basis to review existing risks and identify new ones.
2A	Risk Assessment and Risk Ranking in Preparation for RAMP	PG&E identifies different consequence severity categories, called "outcomes" (e.g., ignition resulting in a small fire during a fire weather warning occasion) based on available data. The consequence distribution for each outcome is determined using utility-specific and industry data, supplemented with subject matter expertise. PG&E estimates the frequency of risk events based on utility data where available and supplements it with industry data and subject matter expertise.

⁴⁰ Step 2B in the settlement agreement is applicable only to the Risk Assessment and Mitigation Phase (RAMP) and is therefore excluded from this table.

TABLE PG&E-5-4: PG&E'S METHOD FOR COMPLYING WITH
THE S-MAP SETTLEMENT AGREEMENT³⁷
(CONTINUED)

S-MAP SA Step	Description	PG&E Implementation
3	Mitigation Analysis for Risks in RAMP	The wildfire risk bow-tie for presenting risk is shown in Section 4.2. PG&E developed the tranches by analyzing available data and identifying different risk profiles (e.g., ignitions caused by transmission assets in HFTDs versus ignitions caused by distribution assets in HFTDs). Each element of risk in the system (e.g., mile of distribution circuit in HFTDs) is classified into a tranche and shares a risk profile with other elements in the tranche. Calculations like risk scores and risk spend efficiency scores (RSEs) were also implemented consistent with this step. Assumptions and implementation details are described below

Calculating A Risk Score

Consistent with Step 3/Row 13 of the S-MAP SA,⁴¹ PG&E calculates risk scores for risks on its Enterprise Risk Register (ERR) as the product of the Likelihood of a Risk Event (LoRE) and the Consequences of a Risk Event (CoRE): LoRE x CoRE

Following the requirements in the S-MAP PG&E calculates a risk score that represents the score *per unit of exposure in the tranche* (for example for wildfire, the unit of exposure is miles of circuit in a tranche).

The risk score is multiplied by the number of exposure units in the tranche to obtain the tranche risk score. The tranche risk score can also be calculated by multiplying the *frequency* of a risk event by CoRE, where frequency is the product of the number of exposure units in the tranche multiplied by LoRE.

PG&E calculates the expected value of the CoRE using Monte-Carlo methods. The attribute level distributions are specified, and parameters are determined from utility-specific data, supplemented by industry data or subject matter expertise. Using the distributions, each attribute (i.e., safety, electric reliability, gas reliability) is simulated over multiple trials, and the MAVF values are calculated by applying the MAVF to each trial. The CoRE is estimated by calculating the average MAVF value of all the trials.

To calculate post-mitigation risk scores and risk reduction, PG&E estimates how specific mitigations reduce event frequencies and/or attribute distribution parameters (e.g., forecasted reductions in the distribution mean or standard deviation, etc.). The post-mitigation risk scores calculated in this manner are compared against pre-mitigation scores to determine risk reduction.

⁴¹ Step number 13 in the S-MAP SA, Appendix A, is "Calculation of Risk" in the section, "Mitigation Analysis for Risks in RAMP."

Risk spend efficiencies (RSE) are determined for each mitigation by dividing the risk reduction by the total cost of the mitigation program. Step 3/Row 25 of the SA directs PG&E to consider the full set of benefits and use present values in RSEs. To do this, PG&E calculates pre- and post-mitigation risk scores annually over the full life of the mitigation program, and discounts both the risk reduction scores, and the program costs by the PG&E utility discount rate.

5.5 Planning for Workforce and Other Limited Resources

Include a showing that the utility has an adequately sized and trained workforce to promptly restore service after a major event, taking into account employees of other utilities pursuant to mutual aid agreements and employees of entities that have entered into contracts with the utility.

PG&E described its efforts for providing adequate resources to respond to major events in Section 5.3.9. However, there are considerable work execution risks beyond major events that must be considered and carefully managed. PG&E's 2020 WMP continues to outline an ambitious volume of work activities as part of our commitment to aggressively reducing the wildfire risk facing the communities we serve. While PG&E has developed robust work plans in support of the work volume targets outlined in this WMP there are consider execution risks associated with completing all work in the various wildfire programs. Primary areas of execution risk, several of which were experienced in 2019 include:

- Access issues including due to weather, snowfall or other physical access restrictions, environmental regulations or restrictions, property owner objections, or access rights;
- Limited volume of and access to trained, qualified and *safe* personnel to perform targeted work;
- Inability to secure material, particularly for programs that leverage specialized equipment including automated sectionalization, system hardening, weather station and camera installations;
- Electric system access restrictions, specifically the inability to schedule timely transmission system clearances to allow for work to be performed; and/or
- Natural disasters (e.g., earthquakes), pandemics, and other natural hazards that that could cause the company to be unable to perform as intended.

PG&E works continuously to monitor and manage execution risks and has plans in place to mitigate these risks should they arise through actions including, but not limited to:

- In work areas where resource constraints may exist, efforts have been made in the planning process to balance the work and resources to ensure an executable plan exists by reprioritizing work, accelerating hiring, identifying work efficiencies and bundling work where possible; contingency plans have also been identified to shift resources to the highest priority and most time-sensitive work as necessary;
- Historical weather patterns (i.e. snow levels, typical rain or snow timing) have been incorporated into work planning and geographic scheduling of work;
- Identifying available, alternate materials providers and assessing material quality for use in PG&E's system; and,

- Identifying sources of qualified personnel and assessing if the addition of such personnel maintains workforce and public safety, as well as work quality.

In connection with the last point, in 2019, PG&E investigated partnering with local departments of public works to assess if they had qualified personnel and resources that PG&E could leverage to support asset inspections or vegetation management work. After initial investigations, PG&E determined that leveraging municipal employees to perform asset inspections or repairs was not likely to be feasible due to utility labor agreements and required qualifications (i.e. IBEW journeyman status) which were identified to be uncommon amongst municipal employees.

PG&E's team identified 23 priority communities to engage with on a possible partnership. These communities were chosen due to their location within Tier 2 or Tier 3 HFTD areas and where local governments' human resources websites listed job descriptions that could potentially overlap with utility inspection and vegetation management positions, such as park maintenance supervisor, public works maintenance worker, vegetation & fire ecologist and tree trimmer, among others. Through preliminary discussions several communities expressed that such an arrangement would not be of mutual benefit to them at this time due to their own resource constraints. However, a few communities have at least expressed interest in continuing the conversation. As of January 2020, no resource sharing agreements appear likely but these discussions are on-going and contribute to PG&E's overall community engagement and partnership efforts.

In summary, PG&E's 2020 WMP work targets remain ambitious, in alignment with our aggressive focus on reducing wildfire risk. While a number of execution risks, some within the utility's control and many not (weather, environmental restrictions, etc.), could derail our plans, we have incorporated lessons learned from the 2019 WMP implementation and will continue to adjust and refine our schedules and approaches in making every effort to deliver on the wildfire risk reduction efforts outlined in this plan.

5.6 Expected Outcomes of 3-Year Plan

5.6.1 Planned Utility Infrastructure Construction and Upgrades

Explain how the utility expects the geographic location of transmission and distribution lines to shift over the three-year plan period and discuss its impact on 1) the utility's risk exposure and 2) the utility's wildfire mitigation strategy. Outline portions of grid within HFTD that are highest cost to serve, by highlighting circuits or portions of circuits that exceed \$0.5M per customer in capital cost required to harden. Provide justification for the level of hardening required and why the lowest cost path to harden this equipment exceeds \$0.5M per customer, including by describing the various alternatives that were considered to reduce ignition probability and estimated wildfire consequence. For each of these sections of the grid, outline any analysis that was conducted around islanding, serving with microgrids, or providing backup generation, all to reduce the impact of PSPS events and reduce ignition probability and estimated wildfire consequence at the lowest possible cost.

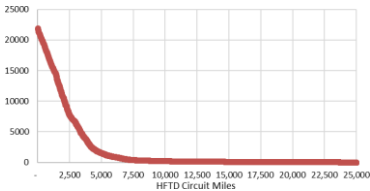
Discuss how the utility wildfire mitigation strategy influenced its plan for infrastructure construction (in terms of additions or removal of overhead lines, including undergrounding of overhead lines) as detailed in Section 3.4.2. Discuss how the utility wildfire mitigation strategy influenced its plan for upgrades to overhead lines and substations as detailed in the Section 3.4.2.

5.6.1.1 Changes in Geographic Location of Facilities

Over the next three years, PG&E expects that geographic location for distribution facilities will begin to shift due to targeted relocation of overhead to underground facilities in certain areas within the HFTDs. PG&E has planned to relocate approximately 150 miles of existing overhead distribution lines to underground distribution lines, although this is subject to change depending on estimating and engineering as PG&E described in more detail in the 2020 GRC proceeding. Also, in some cases, PG&E may also elect to remove distribution lines in lieu of a non-wires solution, such as a remote grid / microgrid solution to serve customers. Based on PG&E's relative mitigation effectiveness assessment, relocating overhead distribution facilities to be underground facilities will have a 100% effectiveness of reducing ignitions attributed to PG&E's electric assets.

Although overhead system hardening efforts (e.g., covered conductor installation, pole replacement, exempt equipment replacement, etc.) typically will not change the geographic location of those facilities, it is projected to result in a relative risk mitigation effectiveness of 56% of reducing ignitions attributed to PG&E's electric assets. PG&E's approach to its wildfire mitigation strategy is to prioritize addressing its highest wildfire risk distribution lines via system hardening efforts. The following figure depicts relative wildfire risk score versus PG&E distribution feeder line mileage. As depicted in the chart below, approximately 95% of the wildfire risk is in 22% of the distribution line miles. Currently, there are approximately 25,200 circuit miles in HFTDs, so that 22% equates to approximately 5,500 circuit miles that has 95% of the wildfire risk.

FIGURE PG&E 5-26: SYSTEM HARDENING REMAINING RELATIVE RISK SCORE



As PG&E continues its system hardening efforts, the wildfire risk in PG&E's circuits should continue to decrease over time.

Within the next three years, the geographic location of PG&E's transmission lines are not projected to change significantly. However, furthered inspections, repairs, planned upgrades and replacements will reduce wildfire risk. Since the transmission system is mostly comprised of networked lines, a cost per customer is not routinely calculated for

repair, upgrade or replacement work. In addition to upgrades and replacements, other efforts to reduce wildfire risk and PSPS impact related to system hardening are discussed in Section 5.3.3.

5.6.1.2 Costs of System Hardening Exceeding \$0.5 Million Per Customer

PG&E does not currently have a cost analysis for all potential system hardening projects. As locations are recommended and reviewed in detail, alternatives for hardening are considered, including removal, relocation, non-wire alternatives like remote or microgrid, overhead and underground hardening. While it is appropriate to consider costs as one factor in the hardening strategy for each location, the customer count served by that line segment may not be the most appropriate normalizing factor. It is important to consider the overall potential impact to the wider community in the event of an ignition on such a line. A number of factors must be taken into account when evaluating hardening alternatives, which may result in a higher than expected cost per served customer for those line sections most at risk for high fire spread and consequence risk that happen to serve a lower volume of customers.

5.6.1.3 Wildfire Mitigation Strategy Impact on Construction and Upgrades

In order to build a more robust and hardened system, upgrades, as highlighted in PG&E’s distribution System Hardening standard (TD-9001B-009, discussed in more detail in Section 5.3.3.17), will continue to place constraints on work execution efforts for all work planned in HFTDs. PG&E continues to work to mitigate risks related to material procurement and identification of construction resources required to inspect and re-construct infrastructure to the new standard. These new standards for deploying covered conductor and sizing of structures according to wind speeds will impact span lengths, possibly requiring more poles than historically deployed, and will require relocation of lines in some instances. This in turn may require additional rights-of-way for lines or poles or guy wires which places a burden on the timing of execution and costs required for negotiating new routes / land rights with property owners. These factors will continue to impact all construction planned in HFTD areas, not just hardening specific projects, as the new standard is applicable to all non-emergency and maintenance work.

Instructions for Table 31

Assume weather patterns for each year are as consistent with the 5-year historical average and that wildfire mitigation initiatives are implemented according to plan. Report change in drivers of ignition probability based on WMP implementation according to whether or not near misses of that type are tracked, the number of incidents anticipated per year (e.g., all instances of animal contact regardless of whether they caused an outage, an ignition, or neither), the rate at which those incidents (e.g., object contact, equipment failure, etc.) are anticipated to cause an ignition in the column, and the number of ignitions that those incidents are anticipated to cause by category. List additional risk drivers tracked in the “other” row and additional rows as needed.

Annual ignition frequency will vary significantly based on precipitation patterns and other climatological factors that influence vegetation and fuel moisture.

Table 31-1 (Distribution) and Table 31-2 (Transmission) below show the change in drivers of ignition probability taking into account planned initiatives, for each year of plan.

PG&E estimates a 10% reduction in vegetation-caused, equipment failure and animal-caused ignitions from the 2019 level due to planned System Hardening, Enhanced Vegetation Management and tag repair work that is planned for 2020 onwards. The 10% reduction is derived from the risk prioritization of work, estimation of combined CWSP mitigation effectiveness and associated ignition risk reductions. The same reduction trend of 10% is anticipated in 2021 and 2022.

PG&E utilizes 2019 (actual) incidents as a basis for estimation of 2020-2022 incidents.

PG&E utilizes 2019 (actual) ignitions as a baseline for estimation of 2020-2022 ignitions.

PG&E assumes that 2020- 2022 ignition to incident ratio remains as same as 2019 ignition to incident in Table 11. PG&E utilizes the 2019 ignition to incident ratio along

with the estimated mitigated ignitions in 2020-2022 in order to approximate incidents frequencies in 2020-2022.

With the above analysis, PG&E estimates an 8% reduction for HFTD ignitions in 2020, 2021 and 2022, year over year.

Note that the validity of these assumption will need to be tested with time; annual ignition frequency will vary significantly based on precipitation patterns and other climatological factors that influence vegetation and fuel moisture.

**TABLE 31-1: CHANGE IN DRIVERS OF IGNITION PROBABILITY TAKING INTO ACCOUNT PLANNED INITIATIONS,
FOR EACH YEAR OF PLAN – DISTRIBUTION**

Incident type by ignition probability driver	Detailed risk driver	Are near misses tracked ?	Number of incidents per year				Average percentage likelihood of ignition per incident			Number of ignitions (mitigated)			
			2019 (Actual)	2020	2021	2022	2020	2021	2022	2019 (Actual)	2020	2021	2022
Contact from object	All types of object contact	Y	13,434.00	13,094.17	12,788.32	12,513.05	1.88%	1.88%	1.88%	253.00	246.60	240.84	235.66
	Animal contact	Y	2,072.00	2,034.33	2,000.42	1,969.91	3.19%	3.19%	3.19%	66.00	64.80	63.72	62.75
	Balloon contact	Y	464.00	464.00	464.00	464.00	3.02%	3.02%	3.02%	14.00	14.00	14.00	14.00
	Vegetation contact	Y	8,167.00	7,807.10	7,483.19	7,191.67	1.44%	1.44%	1.44%	118.00	112.80	108.12	103.91
	Vehicle contact	Y	1,835.00	1,835.00	1,835.00	1,835.00	2.02%	2.02%	2.02%	37.00	37.00	37.00	37.00
	Contact from Object - Other	Y	896.00	896.00	896.00	896.00	2.01%	2.01%	2.01%	18.00	18.00	18.00	18.00
All types of equipment / facility failure	All types	Y	13,031.00	12,835.54	12,659.62	12,501.29	1.07%	1.07%	1.07%	140.00	137.90	136.01	134.31
	Capacitor bank failure	Y	70.00	70.00	70.00	70.00	10.00%	10.00%	10.00%	7.00	7.00	7.00	7.00
	Conductor failure—all	Y	3,382.00	3,328.60	3,280.54	3,237.29	2.25%	2.25%	2.25%	76.00	74.80	73.72	72.75
	Conductor failure—wires down	Y	1,593.00	1,593.00	1,593.00	1,593.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Fuse failure—all	Y	345.00	345.00	345.00	345.00	0.58%	0.58%	0.58%	2.00	2.00	2.00	2.00
	Fuse failure—conventional blown fuse	Y	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Lightning arrester failure	Y	130.00	130.00	130.00	130.00	3.08%	3.08%	3.08%	4.00	4.00	4.00	4.00
	Switch failure	Y	189.00	179.55	171.05	163.39	2.12%	2.12%	2.12%	4.00	3.80	3.62	3.46
	Transformer failure	Y	3,962.00	3,905.40	3,854.46	3,808.61	0.53%	0.53%	0.53%	21.00	20.70	20.43	20.19

**TABLE 31-1: CHANGE IN DRIVERS OF IGNITION PROBABILITY TAKING INTO ACCOUNT PLANNED INITIATIONS,
FOR EACH YEAR OF PLAN – DISTRIBUTION
(CONTINUED)**

Incident type by ignition probability driver	Detailed risk driver	Are near misses tracked ?	Number of incidents per year				Average percentage likelihood of ignition per incident			Number of ignitions (mitigated)			
			2019 (Actual)	2020	2021	2022	2020	2021	2022	2019 (Actual)	2020	2021	2022
All types of equipment / facility failure	Pole failure	Y	1,162.00	1,162.00	1,162.00	1,162.00	0.34%	0.34%	0.34%	4.00	4.00	4.00	4.00
	Insulator failure	Y	374.00	355.30	338.47	323.32	1.07%	1.07%	1.07%	4.00	3.80	3.62	3.46
	Crossarm failure	Y	1,001.00	1,001.00	1,001.00	1,001.00	0.20%	0.20%	0.20%	2.00	2.00	2.00	2.00
	Voltage Regulator failure	Y	59.00	57.03	55.26	53.67	5.08%	5.08%	5.08%	3.00	2.90	2.81	2.73
	Recloser failure	Y	106.00	106.00	106.00	106.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Guy/Span Wire failure	Y	58.00	58.00	58.00	58.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Sectionalizer failure	Y	3.00	3.00	3.00	3.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Equipment failure - Other	Y	2,190.00	2,173.15	2,157.99	2,144.35	0.59%	0.59%	0.59%	13.00	12.90	12.81	12.73
Wire-to-wire contact / contamination	Y	Y	16,357.00	16,357.00	16,357.00	16,357.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other	Other	Y	1,746.00	1,746.00	1,746.00	1,746.00	2.23%	2.23%	2.23%	39.00	39.00	39.00	39.00

**TABLE 31-2: CHANGE IN DRIVERS OF IGNITION PROBABILITY TAKING INTO ACCOUNT PLANNED INITIATIONS,
FOR EACH YEAR OF PLAN – TRANSMISSION**

Incident type by ignition probability driver	Detailed risk driver	Are near misses tracked ?	Number of incidents per year				Average percentage likelihood of ignition per incident			Number of ignitions (mitigated)			
			2019 (Actual)	2020	2021	2022	2020	2021	2022	2019 (Actual)	2020	2021	2022
Contact from object	All types of object contact	Y	150.00	147.69	145.62	143.75	8.67%	8.67%	8.67%	13.00	12.80	12.62	12.46
	Animal	Y	32.00	31.47	30.99	30.55	18.75%	18.75%	18.75%	6.00	5.90	5.81	5.73
	Vegetation	Y	64.00	57.60	51.84	46.66	1.56%	1.56%	1.56%	1.00	0.90	0.81	0.73
	Mylar balloon	Y	9.00	9.00	9.00	9.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Car pole	Y	25.00	25.00	25.00	25.00	16.00%	16.00%	16.00%	4.00	4.00	4.00	4.00
	Third-Party (foreign object /aircraft/ vandalism)	Y	20.00	20.00	20.00	20.00	10.00%	10.00%	10.00%	2.00	2.00	2.00	2.00
Equipment / Facility Failure	All types of Equipment Failure	Y	132.00	125.40	119.46	114.11	6.06%	6.06%	6.06%	8.00	7.60	7.24	6.92
	Arrestor	Y	0.00	0.00	0.00	0.00	N/A	N/A	N/A	0.00	0.00	0.00	0.00
	Insulator or Bushing	Y	33.00	30.80	28.82	27.04	9.09%	9.09%	9.09%	3.00	2.80	2.62	2.46
	Circuit breaker	Y	8.00	8.00	8.00	8.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Conductor	Y	35.00	35.00	35.00	35.00	2.86%	2.86%	2.86%	1.00	1.00	1.00	1.00
	Connector/ hardware	Y	13.00	13.00	13.00	13.00	7.69%	7.69%	7.69%	1.00	1.00	1.00	1.00
	Other station	Y	20.00	20.00	20.00	20.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Structure line	Y	18.00	18.00	18.00	18.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Switch (line+station)	Y	2.00	2.00	2.00	2.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Transformer	Y	5.00	4.50	4.05	3.65	20.00%	20.00%	20.00%	1.00	0.90	0.81	0.73
	Other Equipment	N/A	0.00	0.00	0.00	0.00	N/A	N/A	N/A	2.00	1.90	1.81	1.73

**TABLE 31-2: CHANGE IN DRIVERS OF IGNITION PROBABILITY TAKING INTO ACCOUNT PLANNED INITIATIONS,
FOR EACH YEAR OF PLAN – TRANSMISSION
(CONTINUED)**

Incident type by ignition probability driver	Detailed risk driver	Are near misses tracked ?	Number of incidents per year				Average percentage likelihood of ignition per incident			Number of ignitions (mitigated)			
			2019 (Actual)	2020	2021	2022	2020	2021	2022	2019 (Actual)	2020	2021	2022
Contamination	All types of contamination	Y	11.00	11.00	11.00	11.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
Disaster	All Types of Disaster (all but 2 Fire)	Y	13.00	13.00	13.00	13.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
Other	All types of Other (e.g., customer or IPF caused)	Y	24.00	24.00	24.00	24.00	25.00%	25.00%	25.00%	6.00	6.00	6.00	6.00
Unknown	Patrol Found No Cause, No Damage	Y	138.00	138.00	138.00	138.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
Weather	All types of Weather	Y	204.00	204.00	204.00	204.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Lightning	Y	109.00	109.00	109.00	109.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Rain	Y	23.00	23.00	23.00	23.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Snow/ Ice	Y	61.00	61.00	61.00	61.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
	Wind	Y	11.00	11.00	11.00	11.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00
Work Procedure Error (WPE)	All types of WPE	Y	21.00	21.00	21.00	21.00	0.00%	0.00%	0.00%	0.00	0.00	0.00	0.00

5.6.2 Protocols on Public Safety Power Shutoff5.6.2 Protocols on Public Safety Power Shutoff

Describe protocols on Public Safety Power Shut-off (PSPS or de-energization), to include:

1. *Strategy to minimize public safety risk during high wildfire risk conditions and details of the considerations, including but not limited to list and description of community assistance locations and services provided during a de-energization event.*
2. *Outline of tactical and strategic decision-making protocol for initiating a PSPS/de-energization (e.g., decision tree).*
3. *Strategy to provide for safe and effective re-energization of any area that was de-energized due to PSPS protocol.*
4. *Company standards relative to customer communications, including consideration for the need to notify priority essential services – critical first responders, public safety partners, critical facilities and infrastructure, operators of telecommunications infrastructure, and water utilities/agencies. This section, or an appendix to this section, shall include a complete listing of which entities the electrical corporation considers to be priority essential services. This section shall also include description of strategy and protocols to ensure timely notifications to customers, including access and functional needs populations, in the languages prevalent within the utility's service territory.*
5. *Protocols for mitigating the public safety impacts of these protocols, including impacts on first responders, health care facilities, operators of telecommunications infrastructure, and water utilities/agencies.*

PG&E's most important responsibility is protecting health, welfare, and safety of its customers and the communities that it serves—including through the provision of safe, reliable electricity. When weather or other circumstances threaten the ability to provide electricity safely, PG&E must take the appropriate steps necessary to protect the public. PG&E's PSPS program proactively de-energizes a portion of the Company's electric system, in the interest of public safety, when there is a potential for a catastrophic wildfire should the lines be left energized. PG&E understands that de-energizing customers has real impacts and is actively working to reduce the impact on its customers.

In 2019, PG&E implemented multiple PSPS events, including some of the largest events in California history. While there were no fatalities in 2019 resulting from wildfires ignited by electrical equipment in PG&E's territory, PG&E acknowledges there is room for further improvement in its implementation of PSPS. PG&E is committed to learning from each incident and advancing practices for events in the future. PG&E is committed to executing its PSPS program in a manner that exceeds Resolution

ESRB-8, D.19-05-042, and other Commission directives⁴² while also minimizing the corresponding risks and mitigating disruptions appropriately.

In this section, PG&E describes its: (1) strategy to minimize public safety risks during high wildfire risk conditions; (2) PSPS decision making protocols (3) re-energization strategy; (4) customer, agency, and external communications; and (5) protocols for mitigating the public safety impacts of these protocols.

⁴² See Resolution Extending De-Energization Reasonableness Notification, Mitigation and Reporting Requirements in D.12-04-024 to all Electric IOUs.

5.6.2.1 Strategy to Minimize Public Safety Risk During High Wildfire Risk Conditions

This section describes strategies to minimize public safety risk during high wildfire risk conditions and details of the considerations, including but not limited to list and description of community assistance locations and services provided during a de-energization event.

As outlined in *Section 4.4 Directional vision for necessity of PSPS*, the 2020-2022 PSPS program plans are targeted to achieve the objective of minimizing the customer impacts of PSPS *without* increasing catastrophic wildfire risk. Key initiatives focus on:

1. Reducing scope, duration, and frequency of PSPS events; and
2. Mitigating impacts on de-energized customers.

PG&E has developed and is continuing to evaluate accelerated strategies for achieving these objectives in 2020 and beyond. These strategies may be adjusted as PG&E continues to evaluate viable opportunities and there may be additional ways in which the PSPS program evolves, including stakeholder input and Commission direction through the open and ongoing Order Instituting Investigation (I.) 19-11-013 and Rulemaking (R.) 18-12-005.

5.6.2.1.1 Reducing Scope, Duration, and Frequency of PSPS Events

PG&E is evaluating various mechanisms for impacting fewer customers and reducing PSPS outage duration. These efforts will only be considered if they *do not* create additional catastrophic wildfire risk. Below is a summary of currently planned initiatives, which is also included in *Section 4.4 Directional vision for necessity of PSPS*.

Distribution Segmentation and System Hardening

PG&E's plan is to enhance its distribution segmentation strategies including: (a) adding sectionalizing devices; (b) circuit reconfiguration / pre-PSPS event switching; and (c) additional system hardening to support PSPS switching. PG&E has identified various distribution lines where additional switching devices coupled with targeted system hardening can be utilized to further sectionalize distribution feeders to minimize the number of customers being impacted by PSPS outages. See also Section 5.3.3.8, Grid Topology Improvements to Mitigate or Reduce PSPS Events.

Transmission Line Sectionalizing

PG&E plans to enhance transmission segmentation strategies including installation of additional SCADA-controlled switches. PG&E has identified various transmission lines where additional switching devices will be utilized to further sectionalize transmission lines to be able to minimize the number of customers impacted by PSPS outages. Additional information found in Section 5.3.3.8 Grid Topology Improvements to Mitigate or Reduce PSPS Events.

Transmission Line Exclusions

Prior to next fire season, PG&E is evaluating all 552 transmission lines in the HFTDs to determine which lines can be removed from future PSPS event scope via: supplemental inspections (ultrasonic), below-grade inspections and repairs, increased VM (expand ROW), accelerated repairs or replacement of assets. Additional information found in Section 5.3.3.8 Grid Topology Improvements to Mitigate or Reduce PSPS Events.

Establishing PSPS Criteria for Hardened Distribution Facilities

PG&E plans to assess and develop decision making criteria for the potential exclusion of "safe-to-operate" hardened distribution facilities from PSPS de-energization during high fire threat weather conditions. Similar to PG&E's current risk-based transmission line assessment used during the event scoping process, distribution line criteria would be based on the wildfire risk reduction associated with the hardened assets. Additional information found in Section 5.3.3.8 Grid Topology Improvements to Mitigate or Reduce PSPS Events.

Microgrids for PSPS Mitigation

PG&E is proposing to pursue resiliency and reliability improvements to mitigate the customer impacts of PSPS through permanent and temporary front-of-the-meter

microgrid solutions.⁴³ Microgrids can reduce the number of customers de-energized during PSPS events, as well as provide additional impact mitigation by energizing shared community resources that support the surrounding population.

Increased Model Granularity

PG&E weather modeling used for PSPS execution will increase weather and fuel model granularity from 3 km to 2 km. On-demand simulations will also be available at 0.67 km. Additional information found in Section 5.3.2 Situational Awareness and Forecasting.

PSPS Guidance Review

PSPS decision making guidance will continue to be assessed, including the evaluation of systematic incorporation of outputs from fire spread and consequence modeling and calibrating outage and FPI models with new data as it becomes available. Additional information found in Section 5.3.2 Situational Awareness and Forecasting.

Restoration Time

In 2019, PG&E's target was to restore service after a PSPS within 24 hours after the weather conditions clear. For 2020, PG&E is aiming for a 50% improvement in daylight restoration time, restoring power for 98% of customers within 12 daylight hours from the time the weather conditions clear. PG&E plans to increase aerial and ground resources and evaluate night patrol capabilities to reduce PSPS restoration time. Additional information found in Section 5.3.6 Grid Operations and Protocols and 5.3.9 Emergency Planning and Preparedness.

⁴³ The targeted units and spend associated with Microgrids for PSPS mitigation in this 2020 WMP are provided for informational purposes only. Microgrids in this category may include temporary mid-feeder microgrids, temporary microgrids located at substations, temporary single-customer microgrids to power critical facilities needed to ensure societal continuity, and permanent distributed generation-enabled microgrid services (DGEMS) at substations. The actual units implemented and spend incurred may change.

5.6.2.1.2 Mitigating Impacts on De-energized Customers

PG&E recognizes the community impacts that result from de-energization and intends to mitigate those impacts through providing backup power support, as well as a number of customer services and programs which is more fully described below. In addition, access to crucial planning and event information is critical to help customers and communities prepare. PG&E provides extensive proactive education and outreach, as well as customer and community notifications during a PSPS event. Additional information can be found in Section 5.6.2.4, Protocols for Mitigating Public Safety Impacts of PSPS.

Backup Power Support for Societal Continuity

PG&E encourages customers to have a plan, which may include backup power in the event their power is turned off due to a PSPS event. However, recognizing that unforeseen circumstances may arise, PG&E may deploy backup generation support in cases involving public health, safety, or environmental risks, or to enable emergency operations of first responders and other infrastructure critical to support societal continuity.

During the October and November 2019 PSPS events, PG&E deployed backup generation support to 41 different sites across 14 counties, with a peak deployment of approximately 41 megawatts (MW) concurrently supporting 26 sites at one time. This was an emergency response deployed by PG&E and its contractors during these PSPS events due to the imminent failure or lack of customer-operated backup generation systems. Customers supported by PG&E with temporary generation included transportation tunnels, water treatment and pumping facilities, medical centers, 911 dispatch centers, jails, and fire departments.

PG&E expects that during PSPS events in 2020 it will be necessary to deploy temporary backup power to facilities, which would be provided in alignment with PG&E's existing Portable Generator Use Standards. PG&E has included a proposal in the Microgrid OIR R.19-09-009 addressing the need to reserve temporary generation capacity for the year.

PSPS Customer Services and Programs

PG&E currently offers services and programs to customers that can assist in limiting the disruption of a PSPS-related outage before, during and after a PSPS event. The programs and services listed below were available in 2019 and will continue to be implemented, promoted and refined during the 2020-2022 program time period. These programs apply broadly to all types of customers and include providing the following: 24/7 information updates, experienced and knowledgeable business teams, continuous power programs, Community Resource Centers (CRCs), Third-Party Partnerships and Grant Programs, and coordination with Critical Facilities and Third-Party Commodity Suppliers.

24/7 Information Updates

PG&E's website and call center allow for customers to have access to 24/7 information before, during and after a PSPS event. PG&E's website provides customers with convenience and flexibility by allowing them access to a variety of topics associated with wildfire preparedness and, when a PSPS event is active, the website is updated with event-specific situational updates, including an address lookup tool to determine customer impacts, PSPS event maps and information, weather awareness updates, and more.

During an event, PG&E will also provide event updates on social media, and also work closely with external media outlets, including multicultural news outlets, to provide broader awareness, critical insight and capture crowdsourced feedback—all of which promotes more effective communication. These resources also serve as backup communications channels should cell service be unavailable for direct customer notifications.

PG&E operates four contact centers in the state of California and provides 24/7 emergency live-agent service for customers to report emergencies, or obtain PSPS-related updates, as needed. PG&E's Contact Center agents are trained in how to handle customers dealing with natural gas and electric emergencies with specific procedures to escalate life-threatening situations, which is available for translation services in 240 languages. PG&E's customer communications support is more fully described in Section 5.6.2.4.

Experienced and Knowledgeable Business Teams

PG&E will provide support to all business customers to help them plan and prepare for a PSPS event. PG&E supports the unique and complex needs of its largest industrial, commercial and agricultural customers with a dedicated team of over 60 customer relationship managers supporting over 3,500 business customers. PG&E's dedicated account management team provides critical information and timely updates before, during and after a PSPS event to its large business customers.

PG&E will continue to engage with business and critical customer accounts to support PSPS and emergency preparedness planning, including topics such as business continuity, backup power options, safety, financing, and sourcing. Further, during EOC activation when a potential PSPS event is anticipated, PG&E will continue to have a dedicated point of contact that will be available 24/7 to conduct direct outreach, provide event updates and answer individualized questions to critical service providers (e.g., telecommunications providers, transmission-level customers and Water Agencies).

Community Resource Centers

In an effort to minimize public safety impacts as a result of the loss of power upon implementing PSPS protocols, PG&E mobilizes (opens) Community Resource Centers (CRC) in potentially impacted counties and tribal communities to provide customers and

residents a space that is safe, energized and air-conditioned or heated (as applicable) primarily during daylight hours (typically from 0800 to 2000). CRCs will:

- Provide communities with PSPS event information, drinks such as bottled water/coffee/tea, non-perishable snacks, ice, blankets (upon request / as needed), and power strips to meet basic charging needs, including charging for cell phones and laptops, small medical devices, as well as Wi-Fi and cellular service access (where possible);
- Meet Americans with Disabilities Act (ADA) requirements and be environmentally compliant;
- Accommodate up to approximately 100 customers at a time;
- Have site owner approval and be located on 1-2 acres of flat and (preferably) paved areas for outdoor locations; and
- Provide transportation for AFN customers to and from center(s) by collaborating with CBOs, local stakeholders and first responders.

PG&E will adapt to the changing needs of CRCs for customers during an event, including varying the offerings available and number and type of CRCs mobilized based on the scale (number of customers impacted) and expected duration of the event based on weather forecasts. Different levels of CRC support include: (1) PG&E-operated mobile answer centers, (2) PG&E-operated outdoor, tented CRC locations, (3) PG&E operated indoor CRC locations (providing backup power where needed), (4) County or Tribal agency-operated support centers whereby PG&E provides temporary backup power and/or reimbursement for reasonable costs for the mobilization and demobilization of agency-operated public support centers.

The number of CRCs set up concurrently during an event will be determined at the time of the event in the EOC with real-time input and agreement on site location from local governments and tribes. Site location execution will depend on vendor availability and land usage agreement status.

PG&E will continue to work with counties, tribes and other agencies to develop a CRC playbook to understand and address their general needs, preferences, and priorities for CRC locations. To build out the playbook, PG&E will leverage previous input received from counties and tribes and will re-circulate the list of potential CRC sites to solicit more feedback. PG&E is currently exploring semi-permanent, indoor CRCs with on-site backup power, while working with property owners to secure agreements. For each potential CRC location, PG&E will conduct Americans with Disability Act (ADA) assessments and confirm readiness for backup power connectivity.

In 2019, during its largest impacting PSPS event (October 23-29, 2019), PG&E stood up 77 CRCs in 30 counties throughout the impacted areas in the territory. As of February 2020, PG&E has almost 100 CRC locations across over 30 counties with agreements executed with land owners. These sites are a mix of both indoor and outdoor locations that may be leveraged as a CRC location during a future PSPS event. Prior to the 2020 wildfire season, however, PG&E is targeting to have approximately 200 indoor CRC locations identified with input from local governments and agreements

executed that may be used during a PSPS event. PG&E will continue to account for feedback from customers and local agencies that may influence the support and resources provided by PG&E for CRCs.

Attachment 2 includes the CRC locations that are currently under agreement with PG&E.

Third-Party Partnerships / Grant Programs

PG&E will continue to collaborate and partner with CBOs that best serve AFN and Medical Baseline customers (e.g., California Foundation for Independent Living Centers). More detail is provided in below in Section 5.6.2.3 related to "Access and Functional Needs (AFN) and Medical Baseline Customers." Based on feedback, lessons learned and research, PG&E is exploring the development of new AFN support and grant programs to assist AFN customers before, during and after a PSPS event related, but not limited to, medical, financial, transportation, and translation needs.

Continuous Power Programs

To help customers prepare for PSPS-related planned outage events, PG&E will continue to spread awareness and educate residential and non-residential customers on the commercially available temporary backup power options by pointing customers to options for portable battery backup power. PG&E will directly engage with backup power vendors to provide insight into customer demand and encourage the development of affordable programs that meet the needs of potentially impacted customers, including financing options.

As of 2019, over 120 MW of battery capacity has been installed at ~8,000 customer sites across PG&E's service area. Beginning early 2020, PG&E will leverage and target the recently approved, updated SGIP to incentivize eligible customers⁴⁴ that meet the equity resiliency criteria located in Tier 2 and Tier 3 HFTD areas adopt battery storage. With a generous incentive that offsets almost 100% of battery and installation costs, targeting Critical Facilities and Critical Infrastructure, as well as Medical Baseline customers, in Tier 2 and Tier 3 HFTDs or who have experienced two or more discrete PSPS events can significantly reduce PSPS impact for the most vulnerable customers in the highest impacted areas.

PG&E will continue to explore additional continuous power-related program offerings, such as on-bill financing, to support backup power needs for potentially impacted customers.

⁴⁴ Customer eligibility for the SGIP program equity resiliency budget is more fully described in D.19-09-027. Key eligibility is focused on either medical baseline customers, a more "narrower subset" of critical facilities in Tier 2 or Tier 3 HFTD areas, or customers that have experiences two or more discrete PSPS events that have the "least ability to fund a storage system."

Coordination With Critical Facilities and Critical Infrastructure

PG&E will continue to maintain an annual process for updating critical facilities designations and contact information in partnership with cities and counties in alignment with the CPUC definition of "critical facilities and critical infrastructure" as described in D.19-05-042. In addition, PG&E's personnel will continue to serve as dedicated point of contact for critical facilities before, during and after a PSPS event.

Through on-going engagement, PG&E plans to continue to coordinate with critical facilities, such as fuel suppliers and refineries, telecommunications providers, transportation, among others, to further understand and more effectively plan for the impacts of a PSPS event on the ability to safely operate these facilities.

When PG&E's EOC is activated for a PSPS event, a single point of contact at PG&E will provide timely updates with event scope and status and answer individual questions for facilities that meet the requirements of being both a critical facility and public safety partner.

Looking forward, PG&E will work to better understand the impact of PSPS events on critical infrastructure, such as bridges, tunnels and mass-transit systems. Additionally, PG&E will develop a resiliency playbook to communicate consistent policy for providing temporary backup power to critical facilities during a PSPS event, as described above under Backup Power Support for Societal Continuity. Finally, PG&E will also explore options to create a working group and cooperative framework to enhance information sharing and preparedness before the next wildfire season, establish realistic service expectations and planning needs, better coordinate during emergency and disaster events, and promote overall resiliency with Telecommunication providers in support of our mutual communities served.

Coordination With Third-Party Commodity Suppliers

Regular communication and education will continue with CCA and DA providers regarding PSPS events and wildfire relief efforts. When PG&E's EOC is activated for a PSPS event, CCA Relationship Managers will provide daily updates on timing, customer and event status and answer individual questions. CCAs are also provided access to the PSPS portal, which includes PSPS event-specific information, including event maps, impacted customers lists, and other relevant event information.

5.6.2.2 PPS Decision-Making Protocols

This section describes PG&E's 2019 process for determining when to initiate a PPS event. PG&E is continuing to evaluate decision-making criteria. There is no singular algorithm that yields an objective result at this time. This ongoing evaluation may result in changes to PG&E's PPS criteria and decision-making process in 2020 and beyond.

PG&E carefully reviews a combination of several factors when determining if power must be turned off for safety, and no single factor ultimately determines a PPS decision. The two key drivers of the decision to initiate a PPS event are PG&E's OPW and FPI forecast models. When there is spatial and temporal concurrence of high FPI and OPW, which means a high potential for outage activity and an increased probability of a large fire, a PPS event is considered. When these conditions align, the FPI is forecasted to reach a rating of "R5-Plus", which indicates high fire danger plus the potential for outage activity. When this level is reached, a combination of other criteria may inform the ultimate decision to shut off power. These include:

- A Red Flag Warning declared by the NWS;
- High Risk forecasts from the Northern and Southern Geographic Area Coordination Centers
- Low humidity levels, generally 20 percent and below;
- Forecasted sustained winds generally above 25 miles per hour (mph) and wind gusts in excess of approximately 45 mph, depending on location and site-specific conditions such as temperature, terrain and local climate;
- Computer simulated fire spread and consequence modeling based on current and forecast weather and fuel conditions;⁴⁵
- Condition of dry fuel on the ground and live vegetation (moisture content); and
- On-the-ground, real-time wildfire related information from PG&E's WSOC and field observations from PG&E field crews.

The first trigger for a potential PPS event is a forecast of fire danger and high wind conditions by PG&E's Fire Science and Meteorology team. PG&E's Meteorology team uses the latest global forecast models to determine potential high-risk conditions that may develop several days out. With the enhanced situational awareness from increased weather stations and advanced modelling, PG&E's Fire Science and Meteorology team predicts conditions specific to local geographic areas as high-risk events approach.

Modeled weather and fuel conditions are combined in a FPI to forecast daily fire danger ratings by FIA. The FPI is a forecast describing the potential for fires to ignite and

⁴⁵ This decision factor was developed and is being tested. It will be further integrated into the fire danger modelling analysis tool for use in 2020. PG&E previously had only ignition spread modeling based on historic climatology.

spread on a scale from "R1" (lowest) to "R5" (highest) specific to each FPI Rating Area. "R5-Plus" indicates there is elevated fire potential plus potential for wind-related outage activity, which may warrant a PSPS event. The FPI model was calibrated using a high-resolution dataset of historical weather, fuel conditions, geographic-features and fires.

The occurrence of strong, outage producing winds separates "R5-Plus" fire danger from "R5" fire danger. PG&E utilizes an OPW forecast to highlight local areas with an escalated probability of outages driven by wind conditions. The OPW model was developed by PG&E's Fire Science and Meteorology team and is a location-specific model developed based on the historic frequency of outages at forecasted wind speeds.

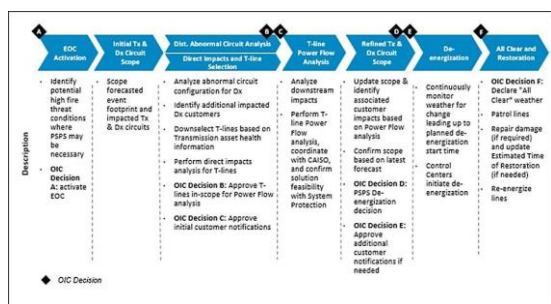
Once PG&E's Fire Science and Meteorology team has identified an upcoming event (typically a period of adverse weather combined with dry fuels) that is being monitored for an increased potential of a PSPS event, they will issue an "Elevated" forecast in the PG&E 7-day PSPS Potential, which is available to the public at PGE.com. This also triggers a transition into a PSPS readiness posture, where PG&E leverages select teams and roles to better prepare and plan for potential PSPS events prior to EOC activation to enhance operational execution. Readiness posture activities are only intended to be completed on an as needed basis, driven by the forecasted PSPS potential and is dependent on the timing and amount of advanced warning for the event.

Once there is a reasonable chance of executing PSPS to reduce public safety risk due to a combination of adverse weather and an increased fire risk, PG&E activates its EOC, with a designated OIC, and PG&E's Meteorology team issues a "PSPS Watch" on PG&E's public facing weather website (pge.com/weather). Under the EOC structure, PG&E Planning and Intelligence, Operations, and other ICS teams continually monitor weather forecasts, as well as local conditions in areas forecasted for "R5-Plus" conditions and update the OIC of the real-time status of the factors listed above.

For a PSPS event, the OIC is responsible for making the following decisions also depicted in the figure below:

- Activating PG&E's EOC for a forecasted PSPS event;
- Approving the transmission lines directly in-scope for the PSPS event;
- Approving initial customer notifications;
- Approving de-energization of distribution and transmission circuits within the final event scope (including indirectly affected transmission circuits outside the weather polygon); and
- Approving "All Clear" after weather conditions subside to begin the process of patrols and restoration.

FIGURE PG&E 5-27: PSPS DECISION MAKING PROCESS WITH OIC DECISION POINTS
(SUBJECT TO CHANGE AS REQUIRED BY PROGRAM EVOLUTION)



The EOC commander for each event is charged with executing each OIC decision. Once the execution of PSPS is probable due to a combination of adverse weather conditions and an increased fire risk, PG&E's Fire Science and Meteorology team will issue a "PSPS Warning" on PG&E's public facing weather website (pge.com/weather). However, this level does not guarantee that de-energization will occur as conditions may change.

For distribution lines, PG&E's fire science and meteorology team will advise the OIC on the potential for a concurrence of heightened outage risk from wind, potential for large fires and the weather event's footprint based on their expertise and interpretation of PG&E's OPW and FPI model forecasts and external forecasts such as Fire Weather Watches issued by NOAA, and forecasts from Northern and Southern California Geographic Area Coordination Centers Predictive Services. PG&E evaluates which distribution lines (if any) pass through the forecasted weather event's footprint, and PG&E's EOC, distribution control center and transmission Grid Control Center will coordinate to ensure customers are identified and notified, and to prepare for possible de-energization.

As part of PG&E's wildfire risk monitoring, it will also review any transmission lines that pass through the meteorological event footprint determined by the meteorology team. The review is conducted in accordance with regulatory standards and in coordination with the CAISO. While no single factor drives a PSPS de-energization decision, some factors for a transmission-level impact include:

- Severity and duration of the weather
- Operability Assessment data

REAX computational wildfire spread and consequence modeling The Operability Assessment data is the product of an asset health model of PG&E's transmission system, which considers the likelihood of a specific transmission asset failure under certain wind loading conditions. To determine the likelihood of a transmission asset failure during wind loading conditions, this model factors the asset remaining strength from field inspections, and asset uncertainty from environmental threats, historical performance, and age. Design adjustments are made based on Subject Matter Expert input and computer aided analysis of structures, and historical outage producing winds through a Bayesian statistical analysis.

There is no single factor or threshold that will automatically trigger de-energization of any particular transmission line. Based on relative wildfire risk calculated for each transmission line in the footprint, PG&E will exercise expert judgment to identify which lines, if any, should be considered for de-energization. PG&E will then conduct fault-duty system protection studies and power flow assessments in coordination with the CAISO to ensure that de-energization of the transmission PSPS scope is feasible and will not compromise reliable bulk power system operations. This step is critical to support compliance with FERC and NERC reliability standards and to help identify the total count of customers who will be impacted. This step may result in a change in downstream PG&E distribution customers impacted by de-energization.

5.6.2.3 Re-Energization Strategy

PG&E will only restore power following a PSPS event after confirming that it is safe to do so. Crews will patrol all transmission, distribution, and secondary mainline facilities within Tier 2 or Tier 3 HFTD areas and within the de-energization scope to identify any damage that requires repair before re-energizing. To reduce the outage impact to customers, PG&E uses helicopter patrols in areas where visibility is not limited by vegetation. PG&E assigns a task force consisting of supervisors, crews, troublemen, and inspectors to each circuit or portions of a circuit. This structure enables PG&E to patrol and perform step restoration⁴⁶ in alignment with the impacted centralized control centers. Any necessary repairs are conducted while patrols continue to allow restoration to proceed as efficiently as possible. As needed and appropriate, PG&E will leverage mutual assistance agreements and contractors to support the patrol, repair, and restoration process.

In 2020, PG&E plans to continue building on the restoration process enhancements made in 2019 with a goal of reducing the length of customer outage after high-risk weather conditions have subsided. In 2019, PG&E's target was to restore service after a PSPS within 24 daylight hours after the weather conditions clear. For 2020, PG&E is aiming for a 50% improvement, restoring power for 98% of customers within 12 daylight hours from the time the weather conditions clear.

While strategies are still being evaluated, potential mechanisms for reducing restoration time include expanding exclusive use helicopter agreements and the commissioning of fixed wing aircraft with MX-15 cameras and infrared technology for night patrols of transmission lines. PG&E will continue to assess these approaches and weather additional enhancements to reduce restoration time are possible.

Additional information regarding PG&E's PSPS re-energization protocols are available in Section 5.3.6.4.

⁴⁶ Step restoration is when a substation is re-energized, and circuits are subsequently safely energized in segments as patrols continue to confirm areas are free of damage or hazards.

5.6.2.4 Customer, Agency, and External Communications

PG&E communicates with customers to prepare for PSPS prior to wildfire season to help customers prepare for a potential PSPS event, and when a PSPS protocol is initiated to notify potentially impacted customers and Public Safety Partners that a PSPS event is forecasted.

Customer and Community Outreach

For 2020-2022, PG&E will continue to implement and enhance the customer and community outreach support listed below and will adjust, as needed and based on feedback and lessons learned. Specifically, PG&E will account for input received from customers and communities gathered during the County and Customer Listening Tours held between December 2019 through February 2020.

Prior to the 2019 peak wildfire season, PG&E designed and executed a comprehensive PSPS community outreach strategy, serving to increase awareness of PSPS and readiness for extended power outages. PG&E also worked with first responders and local communities in advance to enhance customer notifications and ensure a coordinated response when PSPS events are forecasted and/or called. In 2019, PG&E:

- Participated in weekly meetings with the CPUC, Cal OES, CAL FIRE and the other California utilities to standardize the PSPS process and procedures;
- Conducted a statewide PSPS awareness and preparedness campaign in coordination with other California utilities;
- Conducted over 1,080 meetings with cities, counties, agencies, tribes, first responders, community groups, other stakeholders;
- Hosted 17 workshops with more than 930 local emergency services agencies;
- Hosted 23 community open houses and three customer-specific webinars with approximately 3,200 attendees;
- PG&E sent over 17.7 million PSPS related emails to customers and over 18.8 million pieces of PSPS related direct mail, letters and postcards to customers;
- Launched PSPS Weather Forecast and Safety Action Center websites to help customers better prepare;
- Established a secure data transfer portal to share planning information, including maps and customer counts, and event-specific data -- creating over 950 accounts for state and local agencies and tribes to access portal;
- Confirmed 24-hour primary and secondary points of contact for all jurisdictions located within the PG&E service territory to be used during PSPS events; and
- Continued to support local Fire Safe Councils through grant funding.

State Agencies, Counties, Cities, Tribes and Other Local Emergency Responders

PG&E is committed to coordination and collaboration with local, state and federal agencies, as well as with tribes and other local emergency responders. PG&E will continue to conduct PSPS planning outreach, which includes, but is not limited to: one-on-one meetings to have more localized discussions and listening sessions with jurisdictions impacted by PSPS events. PG&E will utilize these meetings to gather feedback and adjust the program, as appropriate. In addition, PG&E will conduct more robust PSPS scenario planning exercises with County OESs, tribes and first responders, and will also continue the following PSPS preparedness activities:

- Gather updated contact information, as needed;
- Identify critical facilities to assist with prioritizing restoration (as feasible) during an event;⁴⁷
- Provide access to the secure data transfer portal (PSPS Portal) in order to share additional customer information quickly during an event; and,
- Provide sample notifications and planning maps.

PG&E will continue to seek and incorporate feedback where feasible to ensure agencies have information and procedures to proactively plan for and respond to a PSPS event.

Outreach to Customers and General Public

PG&E will continue to engage with its customers and the public who may be directly impacted by a PSPS event and will prioritize engagement with those most likely to be impacted by PSPS, which include those served by electric lines which traverse Tier 2 and Tier 3 HFTD areas. PG&E’s messaging surrounding PSPS will transition from awareness to readiness, as awareness is now likely very high.⁴⁸ PG&E will continue direct-to-customer outreach campaigns that are focused on, but are not limited to, building PSPS readiness among customers, gathering updated contact information, sharing backup power safety tips, as well as support the Statewide Public Education and Outreach Campaign that was launched in 2019. PG&E will leverage multiple channels, such as email, letters, postcards, radio and TV broadcasting, print media,

⁴⁷ The list of critical facility entities identified by PG&E, and in coordination with local governments and tribes, is provided directly to the CPUC subject to applicable confidentiality rules. These facilities are identified in alignment with the CPUC definition of critical facilities and infrastructure described in D.19-05-042, and may change based on various factors, such as account status changes, or additional input from local government/tribe, customers or PG&E.

⁴⁸ PG&E PSPS awareness increased from 46% in May 2019 to 62% in August 2019 and is expected to have increased significantly following the multiple and widespread PSPS events that occurred in October 2019.

social media, website, open houses and webinars, face-to-face meetings, and informational videos.

Additional touchpoints for medical baseline customers,⁴⁹ and the AFN community will be conducted, as described below. PG&E will also continue to translate key PSPS materials into multiple languages and also continue to provide live customer support, including translated support in 240 languages through PG&E's call center.

Access and Functional Needs (AFN) and Medical Baseline Customers

PG&E is committed to providing additional services to AFN and medically sensitive customers in advance of and during PSPS events by partnering with organizations whose business it is to assist and provide services to the AFN community. PG&E will continue to engage and collaborate with local governments and community-based organizations (CBOs) that serve AFN groups to encourage awareness and enrollment of the medical baseline program. By focusing additional efforts on understanding the needs of the AFN community, through customer research and surveys and coordinating with relevant regulatory proceedings, PG&E can more strategically act on the lessons learned through outreach, community partnerships and notifications, as applicable.

PG&E will also continue to conduct additional outreach to Medical Baseline-eligible customers to drive participation in the program, collect contact information in preparation for PSPS events, and share other relevant PG&E program and services information to streamline communications, as appropriate. In the outreach conducted, PG&E will also include customers that are tenants of master metered accounts who are not the customer of record with PG&E but can receive the same services as medical baseline customers that are PG&E's customer of record, including additional notifications during a PSPS event, as well as rate discounts.

PG&E will also partner with CBOs in targeted communities to increase their capacity to serve AFN communities, such as medically sensitive customers, low-income, limited-English speaking and tribal customers. Focus will be on emergency preparedness and response, disaster resiliency, expanded access to 211 referral services, and overall resiliency to climate-driven emergencies via the Better Together Resilient Communities program. PG&E will also engage with the CPUC's Disadvantaged Communities Advisory Group to provide relevant PSPS program updates and gain input from participants regarding approaches to support disadvantaged communities.

Through its CBO collaborations, PG&E also seeks to provide additional, customer-specific support to AFN community member customers during a PSPS event, such as medical device charging at local Independent Living Centers (ILCs), accessible transportation to PG&E CRCs, funds for hotel stays and short-term loans of a portable backup power batteries.

⁴⁹ Medical Baseline customers are PG&E customers who are eligible for Medical Baseline tariffs and receive an additional allotment of electricity and/or gas per month. The tariffs are designed to assist residential customers who have special energy needs due to qualifying medical conditions.

Going forward, each year during fire season, between the months of May and November, PG&E will also suppress unenrollment of existing customers in the medical baseline program process to stop the automatic removal of customers that do not renew and/or recertify their eligibility in the Medical Baseline program. This process will operate normally between December and April each year; however, will provide added support for these customers that we know have recently met the medical baseline criteria and would still benefit from the support provided to medical baseline customers during wildfire seasons and during a PSPS event.

In 2020-2022, PG&E will continue to explore additional ways to support medical baseline and AFN customers before and during future PSPS events. New offerings that may be explored include but are not limited to:

- Standing up a PSPS AFN Advisory Committee to gain guidance and agreement on identifying executable offerings (focused on the HFTD areas) to support medically sensitive AFN population;
- Expanding the covered medical devices/conditions in the medical baseline program;
- Adjusting the medical baseline program enrollment process to grant immediate and temporary enrollment⁵⁰ in the program for customers to receive PSPS-related notifications / event support upon customers' request of an application, which helps PG&E be more reflective of the entirety of the AFN community;
- Leveraging the recently approved SGIP to incentivize medical baseline customers in Tier 2 and Tier 3 HFTD areas to adopt battery storage by paying up to 100% of the costs;⁵¹ and
- Providing cold storage (e.g., coolers) to low income and medically sensitive or AFN customers in a high wildfire threat area who may benefit from a cold storage unit to help keep food items or medication from spoiling during a PSPS event.⁵²

Outreach Assessment

PG&E qualitatively evaluates customers' awareness, feedback and recall of PG&E outreach, including wildfire safety and preparedness, through statistically significant research studies, as well as surveys, customer feedback and input from CBOs: measures noted below:

- Research Studies: Beginning in 2019, before and after the start of wildfire season, PG&E conducts semi-annual research studies with customers (in both English and Spanish) to capture distributed, diverse statistically significant awareness and recall

⁵⁰ To be removed if certification not received after a certain to be determined time period.

⁵¹ Authorized by D.19-09-027.

⁵² Proposed offering described in prepared testimony in PG&E Application (A.) 19-11-003 for Energy Savings Assistance and California Alternate Rates for Energy Programs and Budget for the 2021-2026 Program Years.

of PG&E's customer communications, and measure statistically-significant changes over time.

- Surveys: PG&E hosts website surveys that allow customers to provide direct feedback on the site page and topic. PG&E's email newsletters also provide customers the option to score the value of the content and to provide direct comments.
- Customer Feedback: PG&E also regularly reviews customer sentiment received via the Contact Center, the website, and other social outlets during events.
- Input from local organizations: PG&E continues to work with community-based organizations (CBOs) that serve the AFN populations to both amplify messaging and solicit feedback before and after outreach.

PG&E also quantitatively tracks customer engagement at different periods of time throughout wildfire season to understand customer behavior, including:

- Web Traffic: Traffic to relevant pages on PG&E's website, such as wildfire alerts, updates to contact information, wildfire safety pages, safety action center, statewide PSPS program. Website traffic is currently measured by assessing number of unique visitors, visits, and page views.⁵³
- Click-through-rates of advertisements: Click-through-rate of advertisements is an industry-accepted standard that measures the number of people visiting a webpage who access a hyperlink to an advertisement (e.g., wildfire safety). To note, advertisement click-through-rates measure the immediate response to an advertisement, but not necessarily the overall response. Customers may see the advertisement, absorb the messaging and choose to act later.
- Conversion rates / actions taken by customers as a result: Conversion rates of customers is the measurable actions taken by customers based on the outreach (e.g., updating contact information, attending an open house, enrolling in medical baseline program).

Customer Notifications

Recognizing that de-energization for public safety can burden communities with unintended risks and hardships, PG&E is committed to providing notification to potentially impacted stakeholders in advance of, during and after a PSPS event, as weather permits. Advanced notification will be provided to public safety partners. The PSPS notification strategy will comply with CPUC rulings, as weather permits.

PG&E expanded the notification strategies for 2019 and continued to adjust as the company received feedback from state and local agencies, as well as from customers.

⁵³ Unique visitors are the number of individuals that visit the specific webpage. These unique visitors may make multiple visits to the webpage. Page views account for all webpages served by the website (pge.com) whereby a unique visitor goes to multiple pages on the website.

For 2020-2022, PG&E will utilize the strategies below and will adjust outreach plans. PG&E will continue to use all communication channels available during an event: direct to customer notifications, media (multi-cultural news outlets, earned and paid media, social media), website, collaboration with Public Safety Partners and CBOs.

State Agencies, Counties, Cities, Tribes and Other Local Emergency Responders

State agencies, cities, counties and tribes will be notified in advance of residential customers regarding a potential PSPS event in order to aid in preparedness efforts. PSPS event notification and coordination may include and is not limited to:

- Providing updates to the state via the Cal OES form throughout the event;
- Issuing automated notifications throughout the event via phone, text and email;
- Providing the content of customer alerts to share via the city or county website, Nixle, and Nextdoor;
- Providing dedicated single point of contacts for potentially impacted counties and tribes to provide event-specific information in real-time throughout the event;
- Offering PG&E representatives, such as Liaison and GIS experts, to be available to be embedded in local and tribal EOCs, as needed;
- Posting maps and event-specific information on the secure data transfer portal (PSPS Portal) and website, including potentially impacted critical facilities and Medical Baseline customer information will also be posted on the portal
- Coordinating with agencies on ideal CRC locations;
- Managing a dedicated 24-hour PG&E Liaison email address where partners can reach PG&E EOC staff with any questions or requests for information; and
- Hosting local agency and/or State Executive calls, as needed, to provide situational awareness for the event.

Critical Facilities

Critical facilities and critical infrastructure⁵⁴ are those that are essential to public safety and that require additional assistance and advance planning to ensure resiliency during de-energization events. Critical facilities will receive the following notifications and support by PG&E during a PSPS event:

- Notification in advance of customers for preparedness efforts;
- Maps of potentially impacted areas in advance of customer notifications; and

⁵⁴ The terms 'critical facilities' and 'critical infrastructure' can be used synonymously.

- A dedicated single point of contact to communicate frequently via live calls for situation awareness updates and operational support.

As directed in the guidelines for this section, in Attachment 3 to the 2020 WMP, PG&E is providing the CPUC with the confidential list of critical facility entities.⁵⁵

Potentially Impacted Customers

Potentially impacted customers are those within the potential de-energization area of a PSPS event. These customers can continue to expect the following notifications during a PSPS event:

- Direct notifications throughout the event via multiple channels (e.g., phone, text and email), including in-language (translated) notifications and leveraging all available customer contact information; and
- Resources also provided to the general public (noted below).

PG&E will continue to look for opportunities to optimize the frequency and accuracy of notifications and will also explore new solutions and improved technologies to best communicate PSPS event updates and impacts with customers in the channel of their choice. Example approaches include but are not limited to considering new approaches for translated notifications or web technologies, and/or exploring options to provide a more personalized customer experience on the web, call center and/or direct notifications. PG&E will continue to consider feedback from customers, agencies, organizations, and other relevant stakeholders to continue to inform and adjust opportunities to improve the customer notification experience.

Medical Baseline Customers

PG&E customers who are eligible for Medical Baseline tariffs receive an additional allotment of electricity and/or gas per month. The tariffs are designed to assist residential customers who have special energy needs due to qualifying medical conditions. Medical Baseline customers can expect the following during a PSPS event:

- Notifications throughout the event via phone, text and email that request a confirmation of received notification; and
- Additional notifications in an attempt to verify receipt of notifications, such as hourly notification retry attempts for those customers that have not confirmed receipt of their notification and site visits (referred to as "door knocks") if notifications were not previously confirmed by the customer as received.

⁵⁵ The list of critical facility entities identified by PG&E, and with input from local governments and tribes, is provided directly to the CPUC subject to applicable confidentiality rules. These facilities are identified in alignment with the CPUC definition of critical facilities and infrastructure described in D.19-05-042, and may change based on various factors, such as account status changes, or additional input from local government/tribe, customers or PG&E.

Local governments, including cities, counties and tribes will be provided with Medical Baseline customer information through the secure data transfer portal to assist with notifications during an event.⁵⁶ PG&E will continue to explore new approaches for identifying and notifying medically sensitive customers for enhanced notifications, as appropriate.

General Public

In addition to the direct notifications sent to potentially impacted customers, PG&E also provides more channels of awareness to notify the public of a PSPS event including online, through the media and via live call support within PG&E's Call Center. The following methods will be leveraged to provide the general public with information in advance of and during a PSPS event.

- PSPS Zip Code Alerts: Opt-in alerts for non-PG&E account holders to sign up for pre-deenergization notifications based on zip codes;
- Website: On the PG&E website, tools and resources include, but is not limited to, customer impact address lookup tool, PSPS event maps and information, weather awareness updates, PSPS collateral (including translated materials), media engagement and links to social media, and short informational or event-specific videos (ex: process after a "Weather All Clear" is called, PSPS decision making process, American Sign Language (ASL) and translated videos). PG&E continues to ensure web stability and capacity, as well as enhance website functionality and user experience;
- Media: Continue issuing press releases, including to multi-cultural news outlets to ensure message is shared with non-English speaking communities, conducting and live streaming news conferences with ASL translators, participating in media interviews, providing real-time social media event updates (i.e. Twitter, Facebook, Next Door), providing preparedness / safety reminders, among others; and
- Live Agent Call Center Support: Continue to leverage PG&E's four Customer Support Contact Centers before, during and after a PSPS event, which offer support by trained agents that handle customer inquiries, including providing translation services available in 240 languages. PG&E may implement the PSPS call strategy,⁵⁷ as needed, to ensure elevated service with minimal wait times for PSPS customers during a PSPS event.

⁵⁶ Authorized by CPUC Resolution No. L-598 issued on December 5, 2019.

⁵⁷ During an event, PG&E will consider implementing the PSPS call strategy, as needed, to ensure elevated service with minimal wait times for customers potentially affected by an active PSPS event customers. The PSPS Call strategy includes maintaining full staffing across Contact Center Operations and training Credit and Billing reps to be able to handle PSPS call types, and only accepting emergency-related calls (including calls related to downed wires, gas leaks, outages and PSPS) when notifications are sent to over 100,000 customers for an active PSPS event.

5.6.2.5 Protocols for Mitigating Public Safety Impacts of PSPS

In 2020-2022, activities to mitigate the public safety impacts of these protocols, including impacts on first responders, health care facilities, operators of telecommunications infrastructure, and water utilities/agencies are described the above in sections, as well as other sections of the WMP, including:

- PSPS impact mitigation efforts described in Section 5.6.2.1 Strategy to Minimize Public Safety Risk During High Wildfire Risk Conditions;
- Public Safety Partner coordination to collectively plan and prepare for emergencies described in Section 5.3.9, Coordination with Public Safety Partners; and
- Effective communication through providing advanced notifications of a potential PSPS event (weather permitting) to Public Safety Partners prior to customers, providing more granular planning maps and improving the impact map-sharing process, and providing effective situational awareness, including insight into impacted medical baseline customers as described in Section 5.6.2.4 Customer, Agency, and External Communications.

PG&E will continue to seek and adjust the protocols and offerings, as needed, based on feedback from relevant stakeholders and based on lessons learned after each event as described in each post-PSPS event report filed by PG&E.

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION PLAN
SECTION 6
UTILITY GIS ATTACHMENTS

6 Utility GIS Attachments

PG&E is attaching, as separate files, the GIS files outlined in section 2.7 of the WMP Guidelines. Notes associated with these GIS files are provided in section 2.7. These files are included in *Attachment 6: GIS Files*.

6.1 Recent Weather Patterns

6.2 Recent Drivers of Ignition Probability

6.3 Recent Use of PSPS

6.4 Current Baseline State of Service Territory and Utility Equipment

6.5 Location of Planned Utility Equipment Additions or Removal

6.6 Planned 2020 WMP Initiative Activity by End-2022

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION PLAN
APPENDIX 1
GLOSSARY OF DEFINED TERMS

Glossary of Defined Terms

Term	Definition
10-hour dead fuel moisture content	Moisture content of small dead vegetation (e.g. grass, leaves, which burn quickly but not intensely), which can respond to changes in atmospheric moisture content within 10 hours.
Access and functional needs populations	Per Government Code § 8593.3 and D.19-05-042, individuals who have developmental or intellectual disabilities, physical disabilities, chronic conditions, injuries, limited English proficiency or who are non-English speaking, older adults, children, people living in institutionalized settings, or those who are lowincome, homeless, or transportation disadvantaged, including, but not limited to, those who are dependent on public transit or those who are pregnant.
Authority Having Jurisdiction	AHJ, party with assigned responsibility, depending on location and circumstance.
Asset (utility)	Electric lines, equipment, or supporting hardware.
At-risk species	Species of vegetation that are particularly likely to contact power lines in the event of high winds and/or ignite if they catch a spark.
Baseline (ignition probability, maturity)	A measure, typically of the current state, to establish a starting point for comparison.
Carbon dioxide equivalent	Tons of greenhouse gases (GHG) emitted, multiplied by the global warming potential relative to carbon dioxide.
Contractor	Any individual in the temporary and/or indirect employ of the utility whose limited hours and/or time-bound term of employment are not considered as "full-time" for tax and/or any other purposes.
Critical facilities and infrastructure	In accordance with the interim definition adopted in D.19-05-042, those facilities and infrastructure that are essential to the public safety and that require additional assistance and advance planning to ensure resiliency during de energization events, namely: emergency services sector (police stations, fire stations, emergency operations centers), government facilities sector (schools, jails, prisons), healthcare and public health sector (public health departments, medical facilities, including hospitals, skilled nursing facilities, nursing homes, blood banks, health care facilities, dialysis centers and hospice facilities), energy sector (public and private utility facilities vital to maintaining or restoring normal service, including, but not limited to, interconnected publicly owned utilities and electric cooperatives), water and wastewater systems sector (facilities associated with the provision of drinking water or processing of wastewater including facilities used to pump, divert, transport, store, treat and deliver water or wastewater), communications sector (communication carrier infrastructure including selective routers, central offices, head ends, cellular switches, remote terminals and cellular sites), and chemical sector (facilities associated with the provision of manufacturing, maintaining, or distributing hazardous materials and chemicals).
Customer hours	Total number of customers, multiplied by the average number of hours (e.g. of power outage).
Data cleaning	Calibrating raw data to remove errors (including typographical and numerical mistakes).
Dead fuel moisture content	Moisture content of dead vegetation, which responds solely to current environmental conditions and is critical in determining fire potential.
Detailed inspection	In accordance with GO 165, an inspection where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded.

Enhanced inspection	Inspection whose frequency and thoroughness exceeds the requirements of the detailed inspection, particularly if driven by risk calculations.
Evacuation impact	Number of people evacuated, with the duration for which they are evacuated, from homes and businesses, due to wildfires.
Evacuation zone	Areas designated by CAL FIRE and local fire agency evacuation orders, to include both "voluntary" and "mandatory" in addition to other orders such as "precautionary" and "immediate threat".
Fuel density	Mass of fuel (vegetation) per area which could combust in a wildfire.
Fuel management	Removing or thinning vegetation to reduce the potential rate of propagation or intensity of wildfires.
Fuel moisture content	Amount of moisture in a given mass of fuel (vegetation), measured as a percentage of its dry weight.
Full-time employee	Any individual in the ongoing and/or direct employ of the utility whose hours and/or term of employment are considered as "full-time" for tax and/or any other purposes.
GO 95 nonconformance	Condition of a utility asset that does not meet standards established by General Order 95.
Greenhouse gas (GHG) emissions	Health and Safety Code 38505 identifies seven greenhouse gases that ARB is responsible to monitor and regulate in order to reduce emissions: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and nitrogen trifluoride (NF3).
Grid hardening	Actions (such as equipment upgrades, maintenance, and planning for more resilient infrastructure) taken in response to the risk of undesirable events (such as outages) or undesirable conditions of the electrical system in order to reduce or mitigate those events and conditions, informed by an assessment of the relevant risk drivers or factors.
Grid topology	General design of an electric grid, whether looped or radial, with consequences for reliability and ability to support de-energization (e.g., being able to deliver electricity from an additional source).
High Fire Threat District (HFTD)	Per D.17-01-009, areas of the State designated by the CPUC and CAL FIRE to have elevated wildfire risk, indicating where utilities must take additional action (per GO 95, GO 165, and GO 166) to mitigate wildfire risk.
Highly rural region	In accordance with 38 CFR 17.701, "highly rural" shall be defined as those areas with a population of less than 7 persons per square mile.
Ignition probability	The relative possibility that an ignition will occur, probability is quantified as a number between 0% and 100% (where 0% indicates impossibility and 100% indicates certainty). The higher the probability of an event, the more certainty there is that the event will occur. (Often informally referred to as likelihood or chance).
Ignition-related deficiency	Any condition which may result in ignition or has previously resulted in ignition, even if not during the past five years.
Impact/consequence of ignitions	The effect or outcome of a wildfire ignition, affecting objectives, which may be expressed by terms including, although not limited to health, safety, reliability, economic and/or environmental damage.
Initiative	Measure or activity proposed or in process designed to reduce the consequences and/or probability of wildfire or PSPS.
Inspection protocol	Documented procedures to be followed in order to validate that a piece of equipment is in good condition and expected to operate safely and effectively.
Invasive species	Non-native species whose proliferation increases the risk of wildfires.
Level 1 finding	In accordance with GO 95, an immediate safety and/or reliability risk with high probability for significant impact.

Level 2 finding	In accordance with GO 95, a variable (non-immediate high to low) safety and/or reliability risk.
Level 3 finding	In accordance with GO 95, an acceptable safety and/or reliability risk.
Life expectancy	Anticipated years that a piece of equipment can be expected to meet safety and performance requirements.
Limited English Proficiency (LEP)	Populations with limited English working proficiency based on the International Language Roundtable scale.
Live fuel moisture content	Moisture content within living vegetation, which can retain water longer than dead fuel.
Lost energy	Energy that would have been delivered were it not for an outage.
Major roads	Interstate highways, U.S. highways, state and county routes.
Match drop simulation	Wildfire simulation method that takes an arbitrary ignition and forecasts propagation and consequence/impact.
Member of the public	Any individual not employed by the utility.
Multi-attribute value function	Risk calculation methodology introduced during CPUC's S-MAP and RAMP proceedings.
Near miss	An event with significant probability of ignition, including wires down, contacts with objects, line slap, events with evidence of significant heat generation, and other events that cause sparking or have the potential to cause ignition.
Near-miss simulation	Simulation of what the consequence would have been of an ignition had it occurred.
Need for PSPS	When utilities' criteria for utilizing PSPS are met.
Noncompliant clearance	Rights-of-way whose vegetation is not trimmed in accordance with the requirements of GO 95.
Outages of the type that could ignite a wildfire	Outages that, in the judgement of the utility, could have ignited a wildfire.
Outcome metrics	Measurements of the performance of the utility and its service territory in terms of both leading and lagging indicators of wildfire, PSPS, and other consequences of wildfire risk, including the potential unintended consequences of wildfire mitigation work, such as acreage burned by utility-ignited wildfire.
Overcapacity	When the energy transmitted by utility equipment exceeds that of its nameplate capacity.
Patrol inspection	In accordance with GO 165, a simple visual inspection of applicable utility equipment and structures that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business.
Percentile conditions	Top X% of a particular set (e.g. wind speed), based on a historical data set with sufficient detail.
Planned outage	Electric outage announced ahead of time by the utility.
Preventive maintenance (PM)	The practice of maintaining equipment on a regular schedule, based on risk, elapsed time, run-time meter readings, or number of operations. The intent of PM is to "prevent" maintenance problems or failures before they take place by following routine and comprehensive maintenance procedures. The goal is to achieve fewer, shorter, and more predictable outages.
Priority essential services	Critical first responders, public safety partners, critical facilities and infrastructure, operators of telecommunications infrastructure, and water utilities/agencies.
Program targets	Measurements of activity identified in WMPs and subsequent annual updates, in terms of volume or scope of work, such as number trees trimmed or miles of power lines hardened.

Progress metrics	Measurements that track how much utility wildfire mitigation activity has changed the conditions of utility wildfire risk exposure or utility ability to manage wildfire risk exposure, in terms of leading indicators of ignition probability and wildfire consequences.
Property	Private and public property, buildings and structures, infrastructure, and other items of value that were destroyed by wildfire, including both third-party property and utility assets.
PSPS risk	The potential for the occurrence of a PSPS event expressed in terms of a combination of various outcomes of the event and their associated probabilities.
PSPS weather	Weather that exceeds a utility's risk threshold for initiating a PSPS.
Red Flag Warning	RFW, level of wildfire risk from weather as declared by the National Weather Service.
RFW Circuit Mile Day	Sum of miles of utility grid subject to Red Flag Warning each day. For example, if 100 circuit miles were under a RFW for 1 day, and 10 of those miles were under RFW for an additional day, then the total RFW circuit mile days would be 110.
Risk-spend efficiency	An estimate of the cost-effectiveness of initiatives, calculated by dividing the mitigation risk reduction benefit by the mitigation cost estimate based on the full set of risk reduction benefits estimated from the incurred costs.
Rule	Section of public utility code requiring a particular activity or establishing a particular threshold.
Run-to-failure	A maintenance approach that replaces equipment only when it fails.
Rural region	In accordance with GO 165, "rural" shall be defined as those areas with a population of less than 1,000 persons per square mile as determined by the United States Bureau of the Census.
Safety Hazard	A condition that poses a significant threat to human life or property.
Simulated wildfire	Propagation and impact/consequence of a wildfire ignited at a particular point ("match drop"), as simulated by fire spread software.
Span	The space between adjacent supporting poles or structures on a circuit consisting of electric line and equipment. "Span level" refers to asset-scale granularity.
System Average Interruption Duration Index (SAIDI)	System-wide total number of minutes per year of sustained outage per customer served.
Third-party contact	Contact between a piece of electrical equipment and another object, whether natural (tree branch) or human (vehicle).
Time to expected failure	Time remaining on the life expectancy of a piece of equipment.
Top 30% of proprietary fire potential index	Top 30% of FPI or equivalent scale (e.g., "Extreme" on SCE's FPI; "extreme", 15 or greater, on SDG&E's FPI; and 4 or above on PG&E's FPI).
Trees with strike potential / hazard trees	Trees that could either 'fall in' to a power line, or have branches detach and 'fly in' to contact a power line in high-wind conditions.
Unplanned outage	Electric outage that occurs with no advance notice from the utility (e.g. blackout).
Urban region	In accordance with GO 165, "urban" shall be defined as those areas with a population of more than 1,000 persons per square mile as determined by the United States Bureau of the Census.
Utility-ignited wildfire	Wildfires ignited by utility infrastructure or employees, including all wildfires determined by AHJ investigation to originate from ignition caused by utility infrastructure.
Vegetation management	Trimming and clearance of trees, branches, and other vegetation that poses the risk of contact with electric equipment.
Vegetation risk index	Risk index indicating the probability of vegetation-related outages along a particular circuit, based on the vegetation species, density, height, and growth rate.

Weather normalization	Adjusting metrics based on relative weather risk, with RFW circuit mile days as the normalization factor.
Wildfire impact/consequence	The effect or outcome of a wildfire affecting objectives, which may be expressed, by terms including, although not limited to health, safety, reliability, economic and/or environmental damage.
Wildfire risk	The potential for the occurrence of a wildfire event expressed in terms of a combination of various outcomes of the wildfire and their associated probabilities.
Wildfire-only WMP programs	Activities, practices, and strategies that are only necessitated by wildfire risk, unrelated to or beyond that required by minimum reliability and/or safety requirements. Such programs are not indicated or in common use in areas where wildfire risk is minimal (e.g., territory with no vegetation or fuel) or under conditions where wildfires are unlikely to ignite or spread (e.g., when rain is falling).
Wildland urban interface (WUI)	A geographical area identified by the state as a "Fire Hazard Severity Zone", or other areas designated by the enforcing agency to be a significant risk from wildfires, established pursuant to Title 24, Part 2, Chapter 7A.
Wire down	Instance where an electric transmission or distribution conductor is broken and falls from its intended position to rest on the ground or a foreign object.

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION PLAN
APPENDIX 2
ACRONYM LIST

Acronym List

Acronym	Term/Definition
A.	Application
AAR	After Action Reviews
ADA	Americans with Disabilities Act
ADF	Asset Data Foundation
ADMS	Advanced Distribution Management System
AFN	Access and Functional Needs
AHJ	Agency Having Jurisdiction
AI	Artificial Intelligence
AMP	Asset Management Plans
ANSI	American National Standards Institute
API	Application Programming Interface
ASL	American Sign Language
BLM	Bureau of Land Management
CA	California
CAL FIRE	California Department of Forestry and Fire Protection
Cal OES	California Office of Emergency Services
CANSAC	California and Nevada Smoke and Air Committee
CARE	California Alternate Rate for Energy
CBM	Condition-Based Maintenance
CBO	Community Based Organizations
CEMA	Catastrophic Event Memorandum Account
CEQA	California Environmental Quality Act
CERP	Company Emergency Response Plan

Acronym	Term/Definition
CIRT	Centralized Inspection Review Team
CMC	Canadian Meteorologist Centre
CMI	Customer Minutes Interrupted
CoRE	Consequence of Risk Event
CPUC or Commission	California Public Utilities Commission
CRCs	Community Resource Centers
CUEA	California Utility Electric Institute
CWSP	Community Wildfire Safety Program
D.	Decision
DCD	Downed Conductor Detection
DER	Distribution Energy Resource
DFM	Dead Fuel Moisture
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DGEM	Distribution Generation Enabled Microgrid Services
DMS	Demand Management System
D-OH	Distribution-Overhead
DPAM	Dynamic Pattern and Analog Matcher
DRI	Desert Research Institute
DRPP	Distribution Routine Patrol Procedure
DTS-FAST	Distribution, Transmission, and Substation: Fire Action Schemes and Technology
EC	Electric Corrective
ECMWF	European Centre for Medium-Range Weather Forecasts
EDF	Enterprise Data Foundation
EDGIS	Electric Distribution Geographic Information System

Acronym	Term/Definition
EEl	Edison Electric Institute
EF	Equivalent Fatalities
EFD	Early Fault Detection
EOC	Emergency Operations Center
EP&R	Emergency Preparedness and Response
EPIC	Electric Program Investment Charge
EPS	Ensemble Prediction System (from ECMWF)
ESA	Energy Savings Assistance
ETE	Evacuation Time Estimates
ETOR	Estimated Time of Restoration
ETPM	Electric Transmission Preventive Maintenance
EV	Expected Value
EVM	Enhanced Vegetation Management
EQM	Electric Quality Management
FAA	Federal Aviation Administration
FAN	Field Area Network
FAS	Field Automation System
FDA's	Fire Detection and Alert System
FEA	Finite Element Analysis
FERC	Federal Energy Regulatory Commission
FF+	Fire Family Plus (aka Family Plus)
FFWI	Fosberg Fire Weather Index
FIA	Fire Index Area
FMEA	Failure Modes and Effects Analysis
FPI	Fire Potential Index

Acronym	Term/Definition
FRP	Fire Radiative Power
FWW	Fire Weather Warning
GACCs	Geographic Area Coordination Centers
GEFS	Global Ensemble Forecast System
GFS	Global Forecast System
GIS	Geographic Information System
GO	General Order
GRC	General Rate Case
HD	High Definition
HFTD	High Fire-Threat District
HREF	High Resolution Ensemble Forecast
HRRR	High Resolution Rapid Refresh
IA	Internal Audit
IBEW	International Brotherhood of Electrical Workers
ICS	Incident Command Structure
IEEE	Institute of Electrical and Electronic Engineers
IID	Imperial Irrigation District
ILCs	Independent Living Centers
ILIS-ODB	Integrated Logging Information System-Operations Data Base
IR	Infrared
IRWIN	Integrated Reporting of Wildland-Fire Information
IVM	Integrated Vegetation Management
IVR	Interactive Voice Recording
km	Kilometer
kV	Kilovolt

Acronym	Term/Definition
LADWP	Los Angeles Department of Water & Power
LEP	Limited English Proficiency
LF 2.0.0	LANDFIRE Remap 2016
LFM	Live Fuel Moisture
LiDAR	Light Detection and Ranging
LMS	Learning Management System
LNO	Liaison Officers
LoRE	Likelihood of a Risk Event
MAA	Mutual Assistance Agreements
MADIS	Meteorological Assimilation Data Ingest System
MARAC	Mutual Aid Regional Advisory Council
MARS	Multi-Attribute Risk Scores
MAVF	Multi Attribute Value Function
MEDs	Major Event Days
MET	Model Evaluation Tools
mph	miles per hour
NAM	North American Mesoscale Model
NARR	North American Regional Reanalysis
NCAR	National Center for Atmospheric Research
NCEP	National Center for Environmental Prediction
NEETRAC	National Electric Energy Testing Research and Applications Center
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NFDRS	National Fire Danger Rating System
NFMD	National Fuel Moisture Database

Acronym	Term/Definition
NIC	Network Interface Card
NIMS	National Incident Management Systems
NOAA	National Oceanic and Atmospheric Administration
NPS	National Park Service
NWA	Non-Wires Alternative
NWS	National Weather Service
O&M Plan	Operations and Maintenance Plan
OA	Operability Assessment
OES	Office of Emergency Services
OH	Overhead
OII	Order Instituting Investigation
OMS	Outage Management System
OP	Ordering Paragraph
OPW	Outage Producing Wind
OSA	Office of Safety Advocates
OSHA	Occupational Safety and Health Administration
PCORP	PacifiCorp
PD	Partial Discharge
PDAC	Primary Distribution Alarm and Control
PEV	Post Enrollment Verification
PG&E or the Company	Pacific Gas and Electric Company
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIH	Pre-installed Interconnection Hubs
Plan	Wildfire Safety Plan
PLDB	Pole Landing Database

Acronym	Term/Definition
PLDN	PG&E Lighting Detection Network
PMD	Project Management Database
PMO	Project Management Office
POMMS	PG&E Operational Mesoscale Modeling System
PRC	Public Resources Code
PSPS	Public Safety Power Shutoff
PSS	Public Safety Specialists
PT&T	Pole Test & Treat
PWAS	PG&E Wind Alert System
QA	Quality Assurance
QC	Quality Control
R.	Rulemaking
RAMP	Risk Assessment and Mitigation Phase
REFCL	Rapid Earth Fault Current Limiter
RF	Radio Frequency
RFW	Red Flag Warning
RIBA	Risk Informed Budget Allocation
RMAR	Risk Mitigation Accountability Reporting
ROW	Right-of-Way
RSAR	Risk Spend Accountability Reporting
RSE	Risk Spend Efficiencies
SAIDI	System Average Interruption Duration Index
SB 209	Senate Bill 209
SB 247	Senate Bill 247
SCADA	Supervisory Control and Data Acquisition

Acronym	Term/Definition
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SED	Safety Enforcement Division
SEMS	Standardized Emergency Management System
SF6	Sulfur Hexafluoride
SI	Smart Inverter
SIPT	Safety and Infrastructure Protection Teams
SJSU	San Jose State University
S-MAP	Safety Model and Assessment Proceeding
SmartMeter™	Brand Name for Automated Metering Initiative (AMI)
SMEs	Subject Matter Experts
SMUD	Sacramento Municipal Utility District
SOPP	Storm Outage Prediction Model
SSEC	Space Science and Engineering Center
STAR	System Tool for Asset Risk
TA	Tail Average
TD&D	Technology Demonstration and Deployment
T&D	Transmission and Distribution
T-OH	Transmission Overhead
UCLA	University of California Los Angeles
U.S.	United States
USFS	United States Forest Service
USL	Uncoupled Surface Layer
UT	Ultrasonic
VIIRS	Visible Infrared Imaging Radiometer Suite

Acronym	Term/Definition
WAPA	Western Area Power Administration
WBT	Web Based Training
WECC	Western Electricity Coordinating Council
WPE	Work Procedure Error
WRF	Weather Research and Forecast
WRMAA	Western Regional Mutual Assistance Agreement
WSOC	Wildfire Safety Operations Center
WUI	Wildland-Urban Interface
VM	Vegetation Management
VP	Vice President
WSIP	Wildfire Safety Inspection Program
WMP	Wildfire Mitigation Plan
XLPE	Crosslinked Polyethylene

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION PLAN
APPENDIX 3
CONFIDENTIALITY DECLARATION

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

**DECLARATION SUPPORTING CONFIDENTIAL DESIGNATION
ON BEHALF OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)**

1. I, Michael Lewis, am the Senior Vice President of Electric Operations of Pacific Gas and Electric Company ("PG&E"), a California corporation. My business office is located at:

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105

2. PG&E will produce the information identified in paragraph 3 of this Declaration to the California Public Utilities Commission ("CPUC") or departments within or contractors retained by the CPUC in response to a CPUC audit, data request, proceeding, or other CPUC request.

Name or Docket No. of CPUC Proceeding (if applicable): R.18-10-007

3. Title and description of document(s):

1. Attachment 3: List of Critical Facilities per Section 5.6.2.2
2. Attachment 6: GIS Files per Section 6
 - a. cpuc_Grid_MedicalCusts_CONF
 - b. cpucGrid_AllCusts_CONF
 - c. cpucGrid_CriticalCusts_CONF
 - d. Transmission-GIS_CONF.zip
 - e. Distribution-GIS_CONF.zip

4. These documents contain confidential information that, based on my information and belief, has not been publicly disclosed. These documents have been marked as confidential, and the basis for confidential treatment is identified in the below chart and further explained in Appendix A, below.:

Check	Basis for Confidential Treatment	Where Confidential Information is located on the documents
■	Customer-specific data, which may include demand, loads, names, addresses, and billing data (Protected under PUC § 8380; Civ. Code §§ 1798 <i>et seq.</i> ; Govt. Code § 6254; Public Util. Code § 8380; Decisions (D.) 14-05-016, 04-08-055, 06-12-029)	Attachment 3: List of Critical Facilities per Section 5.6.2.2 Attachment 6 - GIS Files_CONF a. cpuc_Grid_MedicalCusts_CONF b. cpucGrid_AllCusts_CONF c. cpucGrid_CriticalCusts_CONF
□	Personal information that identifies or describes an individual (including employees), which may include home address or phone number, SSN, driver's license, or passport numbers; education; financial matters; medical or employment history (not including PG&E job titles); and statements attributed to the individual (Protected under Civ. Code §§ 1798 <i>et seq.</i> ; Govt. Code § 6254; 42 U.S.C. § 1320d-6; and General Order (G.O.) 77-M)	
■	Physical facility, cyber-security sensitive, or critical energy infrastructure data, including without limitation critical energy infrastructure information (CEII) as defined by the regulations of the Federal Energy Regulatory Commission at 18 C.F.R. § 388.113 (Protected under Govt. Code § 6254(k), (ab); 6 U.S.C. § 131; 6 CFR § 29.2)	Attachment 3: List of Critical Facilities per Section 5.6.2.2 Attachment 6 - GIS Files_CONF a. cpucGrid_CriticalCusts_CONF b. Transmission-GIS_CONF.zip c. Distrbution-GIS_CONF.zip
■	Proprietary and trade secret information or other intellectual property and protected market sensitive/competitive data (Protected under Civ. Code §§3426 <i>et seq.</i> ; Govt. Code §§ 6254, <i>et seq.</i> , e.g., 6254(e), 6254(k), 6254.15; Govt. Code § 6276.44; Evid. Code §1060; D.11-01-036)	Attachment 3: List of Critical Facilities per Section 5.6.2.2 Attachment 6 - GIS Files_CONF a. cpucGrid_CriticalCusts_CONF b. Transmission-GIS_CONF.zip

		<u>c. Distribution-GIS_CONF.zip</u>
<input type="checkbox"/>	Corporate financial records (Protected under Govt. Code §§ 6254(k), 6254.15)	
<input type="checkbox"/>	Third-Party information subject to non-disclosure or confidentiality agreements or obligations (Protected under Govt. Code § 6254(k); see, e.g., CPUC D.11-01-036)	
<input checked="" type="checkbox"/>	Other categories where disclosure would be against the public interest (Govt. Code § 6255(a))	Attachment 3: List of Critical Facilities per Section 5.6.2.2 Attachment 6 - GIS Files_CONF a. cpucGrid_CriticalCusts_CONF b. Transmission-GIS_CONF.zip c. <u>Distribution-GIS_CONF.zip</u>

5. The importance of maintaining the confidentiality of this information outweighs any public interest in disclosure of this information. This information should be exempt from the public disclosure requirements under the Public Records Act and should be withheld from disclosure.
6. I declare under penalty of perjury that the foregoing is true, correct, and complete to the best of my knowledge.
7. Executed on this 6th day of February, 2020 at San Francisco, California.



Michael Lewis
Senior Vice President, Electric Operations
Pacific Gas and Electric Company

Appendix A to Confidentiality Declaration

Table 9 of the WMP Guidelines requires the utility disclose to the public for its entire service territory a current baseline state of measurements and variables, one of which is “All utility assets by asset type, model, age, specifications, and condition” by “point, GPS coordinate” (Asset Disclosure). PG&E is greatly concerned about the security risks created by disclosing to the public all of these components on all assets in our entire system. This Asset Disclosure goes beyond disclosing the location of overhead transmission lines and distribution lines, most of which are visible to the public or otherwise accessible via internet maps such as Google Earth. Instead, this required Asset Disclosure includes all electric equipment including, specialized functional equipment (such as reclosers, switches, and interrupters), substation facilities and equipment which are remotely operable and perform sophisticated system reliability and protection functions. For each piece of equipment, PG&E has been asked to provide the specification, model, age, condition, and its location by GPS coordinate.

All utilities are responsible for safeguarding their electric facilities from sabotage and cyber security risks, and with that responsibility comes vigilance and the requirement to challenge or avoid any disclosure that has potential to put the reliability of the electric system and the safety of the public at risk. PG&E believes that broad public disclosure of certain information requested in this proceeding would provide marginal benefit to the general public relative to the significantly enhanced physical security risks. PG&E has repeatedly resisted requests from both private and public entities to publicly disclose sensitive and confidential information that would jeopardize the ongoing safety and operation of its generation facilities and its electric and gas transmission and distribution systems, which serve major metropolitan areas, military bases, major sea ports, airports and Silicon Valley. As a public safety matter and, in some cases, a national security matter, ongoing protection of this sensitive information from public disclosure far outweighs the public interest in its public disclosure. SB699 states: “Physical threats to the electrical distribution system present risks to public health and safety and could disrupt economic activity in California... Ensuring appropriate actions are taken to protect and secure vulnerable electrical distribution system assets from physical threats...are in the public interest.” Broad public disclosure here undercuts PG&E efforts to secure its system assets from threats. For these reasons, PG&E will provide all of the requested information to the CPUC under this Declaration, but does not agree to disclose to the public, information responsive to the Asset Disclosure for 115 kV or above facilities or information that is contained within paragraphs 1 through 8 below at any voltage level, because the potential for public detriment outweighs the public interest in its disclosure:

1. Information and data associated with PG&E’s operation and control of its critical bulk electric system (BES) facilities that are subject the North American Electric Reliability Corporation’s Critical Infrastructure Protection (“NERC CIP”) program and are confidential. These include, but are not limited to, information and data associated with PG&E’s:
 - a. BES cyber system facilities and assets,
 - b. BES cyber assets;
 - c. physical access control systems,
 - d. electronic access control and monitoring systems,
 - e. network topology diagrams, and

- f. physical security perimeter diagrams.
- 2. SCADA enabled devices
- 3. Synchrophasor measurement units
- 4. Protection equipment:
 - a. Reclosers,
 - b. Interrupters,
 - c. Sectionalizers, and
 - d. Fuses.
- 5. Switches
- 6. Voltage Regulating Equipment:
 - a. Regulators,
 - b. Boosters, and
 - c. Capacitors.
- 7. Disconnects
- 8. All substation equipment

The above equipment is either remotely operable, and/or responsible for real-time operation of the electric system and has not already been publicly disclosed. Therefore, providing specifications, GPS location, condition, model and age of such equipment provides essential information that a bad-actor would use to sabotage the electric grid. The aggregate of this information and some of the information singularly, will help identify potential weaknesses of specific facilities, the extent of capabilities and its security functions and potential vulnerabilities associated with PG&E's grid design or operation. The apparent risk of a bad actor using this information for sabotage of the electric system outweighs the benefit of the public in accessing such information. While PG&E understands the interest in permitting the public to access this information to review, analyze, and verify the components of the Wildfire Mitigation Plan and its effectiveness in reducing wildfire caused by utility facilities, such access must stop at the point of risking a compromise of the security and reliability of the electric system PG&E operates. Though it should be obvious, it is worth stating that any information that is disclosed publicly cannot be controlled or reigned in later. There is little to no benefit to making this information publicly available. Third parties do not need the asset characteristics of millions of PG&E's assets to evaluate the effectiveness of PG&E's 2020-2022 Wildfire Mitigation Plan. They do not need precise locations of system protection equipment, substations, and critical facilities. And they do not need it alongside other potentially sensitive information that could facilitate damaging attacks on PG&E's infrastructure. As such, the public interest in not disclosing this information far outweighs the public interest in disclosing it.

Malicious individuals and nation states already target PG&E, seeking bits and pieces of data to map its facilities and systems in order to identify possible and optimal attack vectors. The public disclosure of any single piece of information may not, on its own, provide everything needed to exploit a utility and attack the electric grid. But successive public disclosures of additional pieces of information (and particularly a bulk production of information) will increase the likelihood of a cyber or physical intrusion with a corresponding adverse effect on energy infrastructure. Each successive disclosure fills in some knowledge gaps of those planning to do harm, helping to complete the maps of entity systems. Therefore, it is important to examine,

evaluate and properly narrow the scope of the proposed disclosure to properly balance the public interest with the public risk.

Additionally, the proposed Asset Disclosure includes trade secret information or other intellectual property and protected market sensitive/competitive data, the disclosure of which would put PG&E at an unfair business disadvantage. Detailed public disclosure about each of the assets on the utility system would allow competitors, potential competitors or parties interested in acquiring PG&E facilities to evaluate and assess PG&E facilities for competitive or business purposes that go far beyond the purported and intended need for information to assess PG&E's WMP. PG&E is entitled to protection of its intellectual property, and PG&E does not believe the benefit to the public of receiving such information outweighs the risk of releasing such competitive data to the public and PG&E's competitors.

PG&E will provide to the CPUC GIS information responsive to the Asset Disclosure under this Declaration. However, for the above reasons, PG&E will not disclose to the public this information regarding 115 kV or above facilities or equipment of the types listed in 1-8 above. PG&E will require intervenors to execute a Nondisclosure Agreement and use a password to access remaining GIS information responsive to the Asset Disclosure.

In addition, PG&E will not provide to the public information responsive to the Table 9 request for "Number and location of critical facilities" as this constitutes customer confidential information. However, PG&E will provide this information to the CPUC under declaration. In addition, information responsive to Table 9 requests for "Number and location of customers," and "Number and location of customers belonging to access and functional needs populations" by "Point, GPS coordinate" or "Area, number of people, square mile resolution" are provided to the public so as to not disclose customer confidential information by redacting information showing customers of less than 150. PG&E will provide the unredacted information to the CPUC under this declaration.