Application: 20-09-
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Exhibit No.:
Date: September 30, 2020
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS

PREPARED TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS
PREPARED TESTIMONY

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CHAPTER 1
INTRODUCTION AND OVERVIEW

A. Introduction

Pacific Gas and Electric Company (PG&E or the Company) respectfully requests authorization from the California Public Utilities Commission (CPUC or Commission) to recover costs recorded in three wildfire mitigation memorandum accounts, in our Catastrophic Event Memorandum Account, (CEMA) and in certain other miscellaneous memorandum accounts. The work covered by this application mostly spans the years 2017-2019, although a relatively small portion of work dates back to 2012.

The wildfire mitigation memorandum accounts covered in this application are:

- **The Fire Hazard Protection Memorandum Account (FHPMA)**: We have performed the work recorded to this account in order to mitigate the risk of ignition and the severity of wildfires in the vicinity of the Company's electric distribution assets. In this application, we seek recovery for $292 million in costs recorded to this account, primarily for Vegetation Management (VM) activities from 2012-2019. This work responds to fire safety standards promulgated by the Commission in Rulemaking (R.) 08-11-005 and its successor, R.15-05-006.
- **The Fire Risk Management Memorandum Account (FRMMA) and the Wildfire Mitigation Plan Memorandum Account (WMPMA)**:[1] We have performed the work recorded to these accounts for proactive wildfire mitigation measures arising from, or related to, PG&E's 2019 Wildfire Mitigation Plan (WMP). In this application, we seek recovery for $1.31 billion in costs recorded to these accounts for activities conducted in 2019. This work reduces fire risk in California, improves the safety and reliability of PG&E's system, and protects our customers.

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1 Throughout this testimony, the FRMMA and WMPMA are also referred to in the singular as the WMPMA or as the FRMMA/WMPMA.

In addition to the wildfire mitigation work, this application also seeks recovery for costs resulting from PG&E's response to various catastrophic events. After adjustments, we seek recovery of costs recorded in the CEMA totaling $384 million. The majority of the CEMA costs in this application pertain to two events: the 2017 Tubbs Fire and the 2019 severe January/February winter storms.

Finally, this application includes a request for approximately $77 thousand concerning permitting activities recorded to the Land Conservation Plan Implementation Account (LCPIA), as well as a $3.7 million refund to customers from the Residential Rate Reform Memorandum Account (RRRMA).

B. Summary of Request

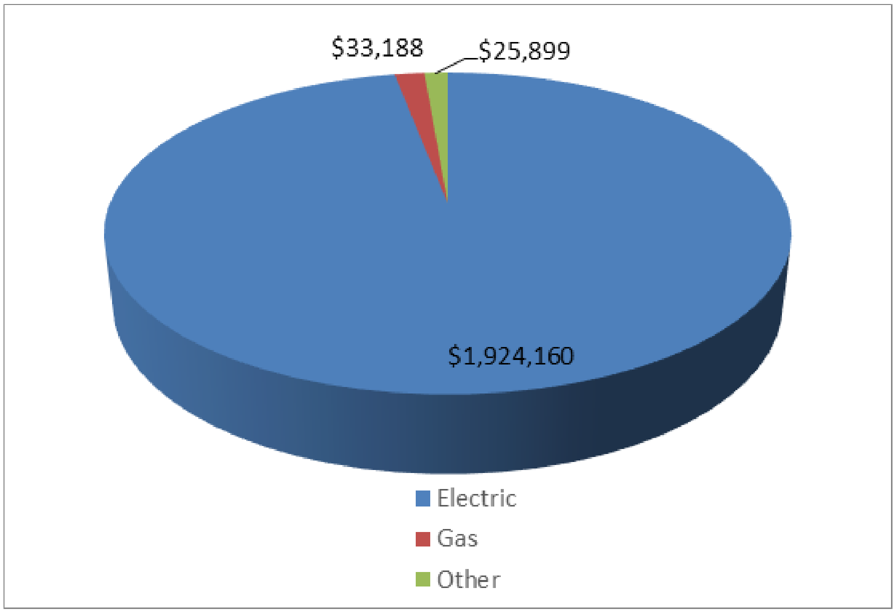
In this application, we seek recovery of costs related to the lines of businesses (LOB) and categories of work summarized in Table 1-1.

TABLE 1-1
SUMMARY OF REQUEST
(THOUSANDS OF DOLLARS)

Line No.	Chapter	Memo Accounts	Expense	Capital	Total
1	Chapter 2: ED – Wildfire Mitigation	FHPMA, FRMMA/WMPMA	$1,003,127	$573,998	$1,577,125
2	Chapter 3: ED – CEMA	CEMA	160,394	186,641	347,035
3	Chapter 4: Gas	CEMA	13,341	19,847	33,188
4	Chapter 5: Power Generation	WMPMA, CEMA, LCPIA	2,986	3,108	6,094
5	Chapter 6: Information Technology (IT)	WMPMA	5,900	17,643	23,543
6	Chapter 7: Customer Care	RRRMA	(3,738)	–	(3,738)
7	Grand Total		$1,182,010	$801,236	$1,983,246

As shown in Figure 1-1, the vast majority of our request stems from expenditures in electric operations.

FIGURE 1-1
SUMMARY OF REQUEST BY ORGANIZATION
(THOUSANDS OF DOLLARS)

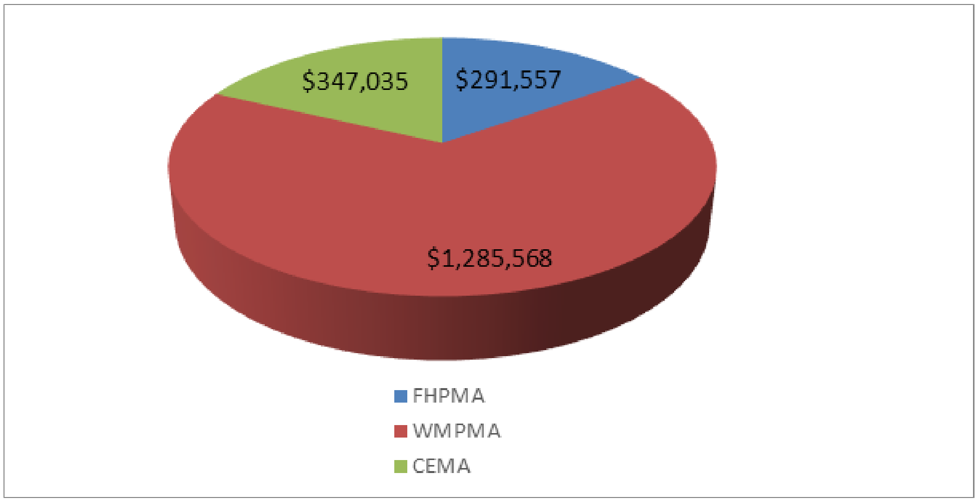


Line No.	Electric	Gas	Other	Total
1	$1,924,160	$33,188	$25,899	$1,983,246

Within electric operations, Figure 1-2 shows the breakdown amongst the various memorandum accounts.[2] One can see that costs booked to the FHPMA and WMPMA collectively comprise most of our request. These costs are described in Chapter 2 of this testimony and are summarized in more detail in Section C of this chapter.

[2] The costs presented in this application have been subjected to various adjustments, such as reductions to account for the Wildfire Order Instituting Investigation (OII) Decision, Investigation (I.) 19-06-015. The adjustments are described in more detail in Chapter 9.

FIGURE 1-2
ELECTRIC DISTRIBUTION REQUEST BY MEMORANDUM ACCOUNT
(THOUSANDS OF DOLLARS)

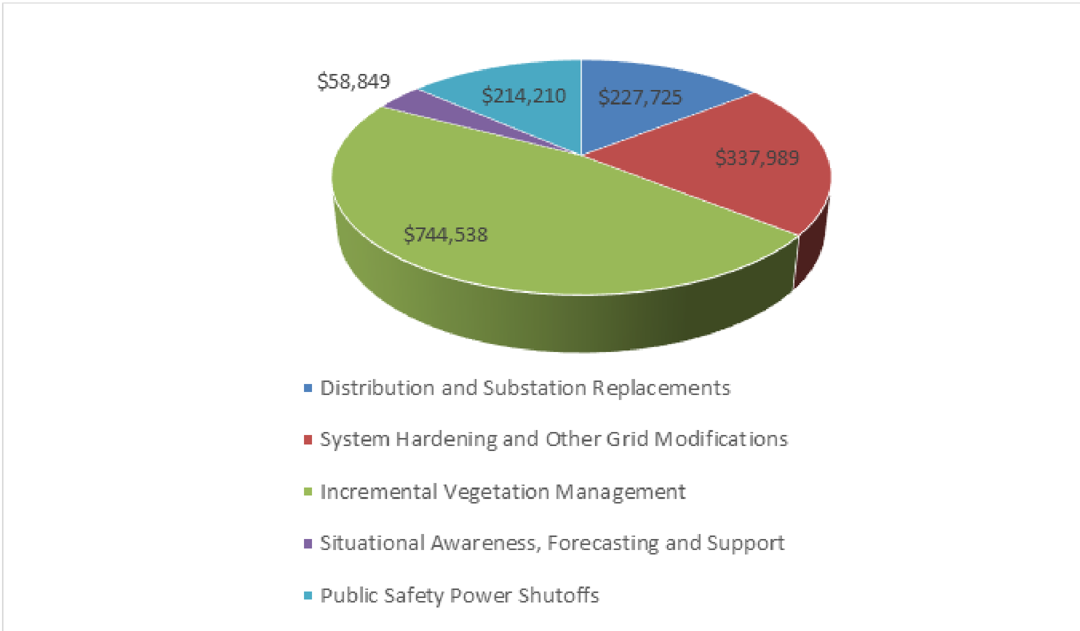


Line No.	FHPMA	WMPMA	CEMA	Total
1	$291,557	$1,285,568	$347,035	$1,924,160

Within our electric distribution costs booked to the WMPMA, Vegetation Management and System Hardening activities are the largest cost categories. The various wildfire mitigation costs for which we seek recovery are summarized in Figure 1-3 below.[3] Figure 1-4 shows the breakdown for expense. Figure 1-5 below shows the breakdown for capital.

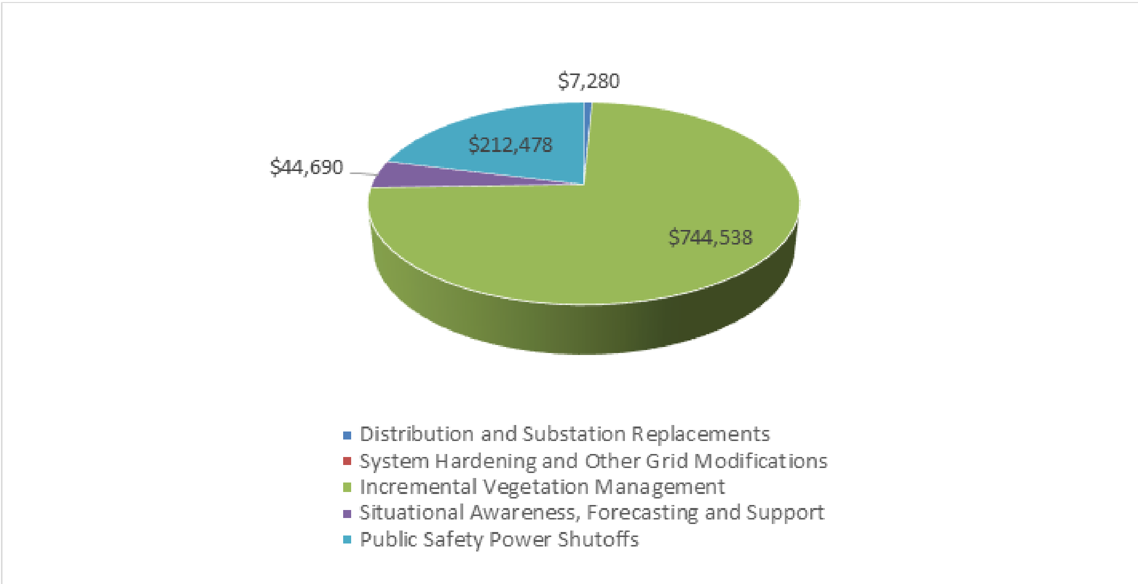
[3] The costs in Figure 1-3 are presented prior to the Ernst & Young reductions discussed below.

FIGURE 1-3
ELECTRIC DISTRIBUTION COSTS – FHPMA AND WMPMA
(THOUSANDS OF DOLLARS)



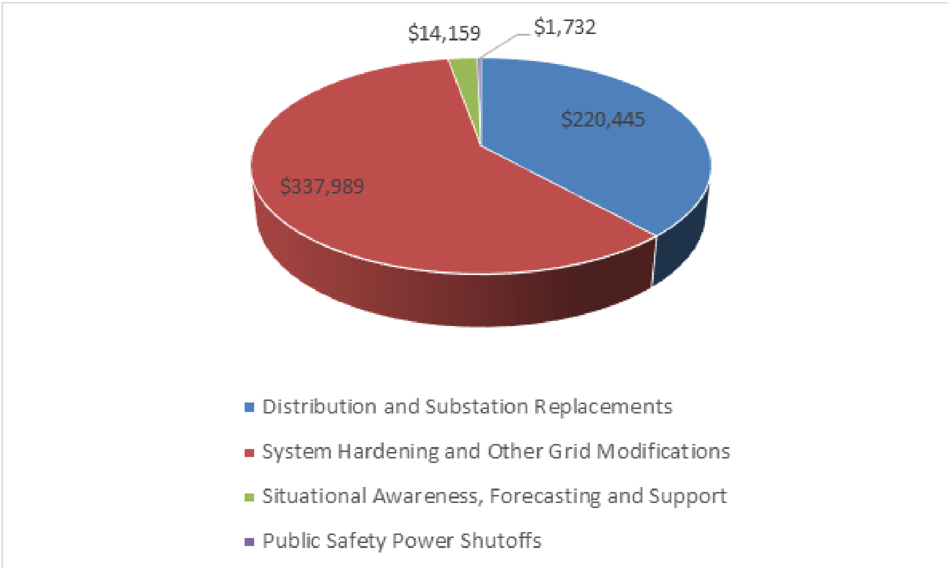
Line No.		Distribution and Substation Replacements	System Hardening and Other Grid Modifications	Incremental Vegetation Management	Situational Awareness, Forecasting, and Support	Public Safety Power Shutoffs (PSPS)	Total
1	Total	$227,725	$337,989	$744,538	$58,849	$214,210	$1,583,313

FIGURE 1-4
ELECTRIC DISTRIBUTION – FHPMA AND WMPMA
EXPENSE
(THOUSANDS OF DOLLARS)



Line No.		Distribution and Substation Replacements	System Hardening and Other Grid Modifications	Incremental Vegetation Management	Situational Awareness, Forecasting, and Support	PSPS	Total
1	Expense	$7,280	–	$744,538	$44,690	$212,478	$1,008,987

FIGURE 1-5
ELECTRIC DISTRIBUTION – FHPMA AND WMPMA
CAPITAL
(THOUSANDS OF DOLLARS)



Line No.		Distribution and Substation Replacements	System Hardening and Other Grid Modifications	Incremental Vegetation Management	Situational Awareness, Forecasting, and Support	PSPS	Total
1	Capital	$220,445	$337,989	–	$14,159	$1,732	$574,325

C. Activities, Costs and Reductions

The activities covered by this application fall into three general areas: (1) wildfire mitigation activities, (2) catastrophic event response, and (3) other. In subsection 1, we summarize the costs related to our request. In subsection 2, we describe the main exclusions and reductions we have made prior to calculating the revenue requirement, which is set forth in Chapter 10 along with our ratemaking proposal.

1. Recorded Costs

a. Wildfire Mitigation Activities

The wildfire mitigation activities underlying the costs in this application can be separated into two broad categories.

The first category, consisting of costs totaling $295 million, are those booked to the FHPMA, which was authorized by the CPUC pursuant to decisions in R.08-11-005 and R.15-05-006 for costs incurred to reduce fire hazards. The costs recorded to this account relate to PG&E's implementation of regulations and requirements adopted to protect the public from potential fire hazards associated with overhead power line facilities and nearby aerial communication facilities. PG&E no longer books costs to the FHPMA as of December 31, 2019, so the resolution of this application will close out this account. The total costs recorded for these activities booked to the FHPMA are summarized in Table 1-2 below.

TABLE 1-2
2012-2019 FHPMA-ELIGIBLE ELECTRIC DISTRIBUTION EXPENDITURES
DISTRIBUTION AND SUBSTATION REPLACEMENTS, INCREMENTAL VM
(THOUSANDS OF DOLLARS)

Line No.	Program	Expense	Capital	Total
1	Incremental Vegetation Management	$295,036	–	$295,036

The second category, consisting of costs totaling $1.31 billion, are those booked to the FRMMA/WMPMA for the electric distribution LOB. The 2019 WMP describes the enhanced, accelerated, and new programs that PG&E implemented to prevent wildfires in 2019 and beyond. We booked costs to the FRMMA before the CPUC approved our 2019 WMP. We booked costs to the WMPMA after the CPUC approved our 2019 WMP.[4]

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4 On March 12, 2019, the CPUC approved PG&E's FRMMA to track costs incurred beginning January 1, 2019, for fire risk mitigation activities that are not otherwise covered in revenue requirements. The FRMMA was authorized by Senate Bill (SB) 901 and Assembly Bill (AB) 1054 to capture mitigation costs of activities not included in a CPUC-approved WMP. We used this account to track wildfire mitigation costs contemplated by our WMP prior to the CPUC's approval of it.

On June 5, 2019, PG&E submitted an advice letter to establish the WMPMA effective May 30, 2019. The purpose of the WMPMA is to track costs incurred to implement the WMP, as required by Public Utilities Code (Pub. Util. Code) Sections 8386 et seq., as modified by SB 901 and subsequent bills, including AB 1054. The WMPMA is required to be established upon approval of a utility's WMP to track costs incurred to implement the plan. The CPUC approved the memorandum account on August 5, 2019, so we recorded any costs incurred in implementing our approved WMP as of the effective date, June 5, 2019.

The magnitude of these costs reflects the fact that we have approached the issue of wildfire mitigation with urgency. Our efforts include significant expansions in Vegetation Management, inspections of electric distribution facilities, system hardening, enhanced controls, the PSPS Program and its situational awareness capabilities, and other programs designed to make our customers and communities safer.

These activities and costs are summarized in the table below:

TABLE 1-3
2019 FRMMA/WMPMA-ELIGIBLE ELECTRIC DISTRIBUTION COSTS
WILDFIRE MITIGATIONS, PSPS, COMMUNITY, AND CUSTOMER SUPPORT
(THOUSANDS OF DOLLARS)

Line No.	Section	Chapter Long Name	Capital	Expense	Total
1	2.B.1	Distribution and Substation Replacements	$220,445	$7,280	$227,726
2	2.B.2	System Hardening and Other Grid Modifications	337,989	–	337,989
3	2.B.3	Incremental VM	–	449,502	449,502
4	2.B.4	Situational Awareness, Forecasting, and Support	14,159	44,690	58,849
5	2.B.5	PSPS	1,732	212,478	214,210
6		Grand Total	$575,325	$713,950	$1,288,276

b. CEMA Costs

PG&E's CEMA costs are recorded pursuant to Pub. Util. Code Section 454.9, which authorizes utilities to record costs of "restoring utility service to customers," "repairing, replacing, or restoring damaged utility facilities," and "complying with governmental agency orders" in connection with declared disasters. The CEMA work reflected in this application pertains to three 2017 fires (i.e., Tubbs, La Porte and Cherokee), as well as 2019 costs for various catastrophic events (i.e., January/February severe storms, the Ridgecrest earthquake, additional costs from the 2018 Carr fire, October wind event, and the Bethel, Camino, and Glencove fires). We recorded to CEMA costs for these events of approximately $218 million in expense and $220 million in capital, although we have reduced our request by $25 million to account for insurance proceeds and $29 million in other reductions.

TABLE 1-4
CEMA-ELIGIBLE EXPENDITURES
(THOUSAND OF DOLLARS)

Line No.	Event by Year	Electric Capital	Electric Expense	Gas Capital	Gas Expense	Power Gen Capital	Power Gen Expense
1	2017 Tubbs Fire	$93,929	$64,342	$17,856	$31,253	–	–
2	2017 La Porte Fire	804	61	–	–	–	–
3	2017 Cherokee Fire	130	90	–	–	–	–
4	2017 Subtotal	$94,864	$64,493	$17,856	$31,253	–	–
5	2018 CARR Fire	$1,228	$491	$307	$139	–	–
9	2018 Subtotal	$1,228	$491	$307	$139	–	–
10	2019 January February Severe Storms	$90,418	$109,327	$255	$819	$3,108	$696
11	2019 Ridgecrest Earthquakes	–	–	2,134	3,260	–	–
12	2019 October Wind	9,263	7,893	–	–	–	–
13	2019 Glencove Fire	200	–	–	–	–	–
14	2019 Bethel Island Fire	24	–	–	–	–	–
15	2019 Camino Fire	10	–	–	–	–	–
16	2019 Subtotal	$99,915	$117,220	$2,389	$4,079	$3,108	$696
17	Grand Total	$196,007	$182,204	$20,552	$35,471	$3,108	$696

c. Other Costs

This application also addresses two other memorandum accounts to which PG&E has recorded costs. First, in this application we seek approximately $80 thousand in permitting costs that our Power Generation organization has recorded to the LCPIA. This memorandum account was established in order to record a portion of the costs incurred by PG&E to process applications presented before the CPUC or Federal Energy Regulatory Commission to implement the Land Conservation Plan approved by the CPUC in Decision (D.) 03-12-035.

Finally, this application includes a $3.7 million refund to customers due to reduced spending in our RRRMA. The Commission already provided PG&E with a revenue requirement for this work. In this application, we seek approval to refund to customers the difference between our spending and the revenue requirement, and to address any questions regarding the spending in this account.

TABLE 1-5
OTHER ELIGIBLE EXPENDITURES
(THOUSANDS OF DOLLARS)

Line No.	Account	Expense	Capital	Total Spending
1	LCPIA	$77	–	$77
2	2017-2019 RRRMA	$(3,738)	–	$(3,738)

2. Exclusions and Reductions

In this application, we have reduced the recorded amounts in a variety of ways in calculating the revenue requirement we are requesting. For instance, as described above in the CEMA discussion, we have reduced the recorded costs to account for insurance proceeds. Other exclusions and reductions are described below.

a. Exclusions Due to the Wildfire OII Decision

On December 17, 2019, PG&E, the Safety and Enforcement Division, the Office of the Safety Advocate, and the Coalition of California Utility Employees jointly submitted to the CPUC a proposed settlement agreement in connection with the Wildfire OII Decision in I.19-06-015. The settlement agreement was approved, with modification in the Wildfire OII Decision. Pursuant to the settlement agreement, PG&E agreed, among other things, to not seek recovery of $36 million of wildfire-related expenses recorded in the FHPMA and of $236 million of wildfire-related expenses recorded in the WMPMA.[5] Amounts related to these disallowances have been excluded from the amounts sought to be recovered in this application.

b. AB 1054

AB 1054, passed by the California legislature in 2019, requires PG&E's shareholders to forego a return on equity on a total of $3.2 billion in certain capital investments. A reduction corresponding to a $2.8 billion portion of the total amount was reflected in PG&E's 2020 GRC settlement that is now pending before the Commission. The remaining capital not accounted for in the GRC—$0.4 billion—is

5 D.20-05-019.

accounted for in this application. The foregone return on equity of this $0.4 billion translates to a revenue requirement reduction of $18.7 million. This $18.7 million reduction, as well as a corresponding reduction to the Allowance for Funds Used During Construction, are removed from our request.

c. CEMA Reductions

Consistent with past practice in CEMA applications, this application reduces the total recorded CEMA costs by: (1) insurance proceeds received for damage to PG&E's facilities from the catastrophic events and (2) certain overhead reductions agreed to by PG&E in a prior CEMA settlement. Moreover, we expect to receive additional insurance proceeds in the future and intend to credit these proceeds to customers.

d. External Auditor Recommendations

PG&E engaged the firm of Ernst & Young to review the wildfire mitigation costs presented herein for accuracy. We did not engage Ernst & Young because of a legal requirement. Rather, we engaged Ernst & Young to validate the costs presented herein and to facilitate the Commission's and stakeholders' review of PG&E's costs.

In summary, Ernst & Young identified no errors or omissions that would materially affect the balances of the above-mentioned memorandum accounts. Further, Ernst & Young found no evidence to contradict our conclusions that the costs were: (1) incurred for activities within the scope of the relevant CPUC-approved memorandum account; (2) accurately recorded; and (3) incremental.

Ernst & Young's review entailed detailed sampling, analysis, and transaction testing. Ernst & Young identified approximately $5.9 million in expense and $328 thousand in capital expenditures as costs of concern. We have removed all of these costs from our request.

D. Accomplishments and Benefits from this Work

This application seeks recovery for costs we have incurred for unprecedented steps we have taken in response to extraordinary challenges in our service area. Wildfire risk and the rate of catastrophic wildfire events in PG&E's service area have increased suddenly and dramatically in recent years.

Prior to the October 2017 North Bay Fires, wildfire risk in California was thought to be primarily a Southern California issue. This prevailing view was reflected in the Commission's 2012 statement that:

> [t]here is no history of catastrophic power-line fires in Northern California, and Northern California does not experience Santa Ana winds that contribute significantly to the risk of catastrophic power-line fires in Southern California.[6]

This view no longer holds. In 2020, we are in the midst of the worst wildfire season in the state's history, with many of those fires occurring in PG&E's service territory. According to the United States Forest Service (USFS), 129 million trees have died in California since 2010—including 27 million from November 2016 to December 2017.[7]

Under the Commission's 2018 Fire-Threat Map, PG&E's service area now contains substantially more High Fire-Threat District (HFTD) areas than the service territories of the other two large investor-owned electric utilities combined. Our infrastructure spans more than 70,000 square miles. More than half of our service area is now recognized by the Commission as extreme or elevated-fire risk. Wildfire season may come to span more than half the calendar year and catastrophic fires have occurred with frightening regularity since 2017. These fundamentals are worsening as California and the West Coast continue to experience the impacts of climate change.

The challenges imposed by climate change on our operations are of a magnitude that we have never faced. The 2018 National Climate Assessment highlighted the confluence of rising temperatures, changing precipitation patterns, and the increase in the number of people living in forested areas as contributing to increased wildfire risk.[8] Perhaps nowhere in the country are these factors present to the degree that they are in PG&E's service area. We are committed to doing the work necessary to operate our system safely and reliably. Wildfire risk mitigation work is essential for promoting public safety and protecting PG&E's facilities in this rapidly changing environment.

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6 D.12-01-032, p. 74.

7 USFS, Dec. 12, 2017 News Release, https://www.fs.usda.gov/Internet/FSE_DOCUMENTS/fseprd566303.pdf.

8 U.S. Global Change Research Program, Fourth National Climate Assessment, Vol. 2.

The Legislature and the Commission, recognizing the need for bold and immediate action, have provided utilities with several mechanisms to facilitate urgent wildfire mitigation efforts. SB 901, enacted in September 2018, requires utilities to submit annual WMPs for approval by the CPUC as directed by the CPUC in R.18-10-007. The WMP must identify and prioritize wildfire risks and the drivers of those risks. It must also describe plans for VM, system hardening, preparation for and response to wildfire events, and protocols for disabling reclosers and deenergizing the electric system. Subsequent bills, including AB 1054, AB 111, SB 70, SB 167, SB 247, and SB 560, modified the WMP requirements, expanding the plan coverage to three years, adding requirements, and transferring review of the plans to a new Wildfire Safety Division.

Consistent with these policies, we are building a more climate-resilient energy network on timetables that would previously have been unimaginable. There are, and will continue to be, significant costs associated with these activities, as well as with our responses to catastrophic wildfire events that continue to demonstrate the urgency of this work.

1. Wildfire Mitigation

The wildfire mitigation work described in this application is part of a multi-year strategy, focused on three key goals: (1) to reduce the potential for fires to be started by electrical equipment; (2) to reduce the potential for fires to spread; and (3) to minimize the frequency, scope and duration of PSPS events. The primary PG&E programs directed to these goals include Enhanced Vegetation Management, system hardening, system automation, PG&E's Wildfire Safety Operations Center, the installation of additional situational awareness tools, and, as a last resort, the use of PSPS—the frequency, scope, and duration of which we are working to reduce.

2. FHPMA Work

These costs are associated primarily with Vegetation Management activities we conducted between 2012-2019, the significant categories of which are described below.

<u>Accelerated Vegetation Management Inspections</u>: D.17-12-024 increased the footprint of HFTD areas in PG&E's service territory, requiring us to accelerate our inspections and increase tree management work to

meet the vegetation clearance requirements in HFTD areas. The decision required compliance with the clearance requirements in Tier 3 HFTD areas by September of 2018. Tier 2 and Zone 1 had similar requirements with a due date of June 30, 2019.

Fuel Reduction: Our Fuel Reduction activities also responded to the expansion of HFTD areas by D.17-12-024 and in alignment with the Fire Prevention Plan. The Decision created expanded areas requiring greater conductor clearances in HFTD areas—those areas with the greatest risk for wildfires.

Accelerated Wildfire Risk Reduction: Like the Fuel Reduction Program, we performed Accelerated Wildfire Risk Reduction work in response to the expansion of HFTD areas in D.17-12-024 and in alignment with the Fire Prevention Plan. The Decision required the creation and implementation of a Fire Prevention Plan for overhead electric facilities in HFTD areas, which included strategies and programs "to reduce the risk of…electrical lines and equipment causing catastrophic wildfires." This Accelerated Wildfire Risk Reduction work was the successor to the Fuel Reduction Program, and served as a predecessor to our more sustainable Enhanced Vegetation Management Program under PG&E's WMP. The Accelerated Wildfire Risk Reduction work informed our understanding of the breadth of tree work needed in HFTD areas, the database support needed, and how to adjust to environmental and customer concerns while addressing fire risks.

3. FRMMA and WMPMA Work

The second category of wildfire mitigation work consists of costs booked to the FRMMA and WMPMA for work that we conducted in 2019. On October 25, 2018, the CPUC opened R.18-10-007 to implement the provisions of SB 901 related to electric utility WMPs. This proceeding provided guidance on the form and content of the initial WMPs, provided a venue for review of the initial plans, and developed and refined the content of and process for review and implementation of WMPs to be filed in future years. The CPUC determined, among other things, how to interpret and apply SB 901's list of required plan elements, as well as what additional elements beyond those required in SB 901 should be included in the WMPs.

SB 901 also requires that WMPs include preventive strategies and programs to minimize the risk of electrical lines and equipment causing catastrophic wildfires, including the consideration of dynamic climate change risks, plans for VM, and plans for inspections of electrical infrastructure. R.18-10-007 did not address utility recovery of costs related to WMPs; SB 901 requires these to be addressed in separate rate recovery applications, such as this one.

Our 2019 WMP outlined work and investments designed to reduce the potential for wildfire ignitions associated with PG&E's electrical equipment in high fire-threat areas. Our 2019 WMP includes measures taken in 2019, including work conducted as part of longer-term plans. The work included new monitoring and weather technologies, electric distribution repairs, incremental VM work, upgraded reclosers and circuit breakers, the installation of more resilient poles and covered power lines, undergrounding, and activities to support PSPS events as a measure of last resort.

On May 30, 2019, the CPUC adopted D.19-05-037 , which generally approved our 2019 WMP (as amended February 14, 2019), subject to certain reporting, data gathering, and other requirements.

In this application, the work booked to the FRMMA and WMPMA has been organized into the following activity categories:

Distribution and Substation Replacements, System Hardening, and Other Grid Modifications: Our Wildfire Safety Inspection Program (WSIP) evaluates the Company's electric infrastructure on an ongoing basis to find and fix potential risks to the safety and reliability of the system. We completed WSIP enhanced inspections of all approximately 685,000 poles in HFTD areas and conducted repairs and replaced overhead assets identified during the course of these inspections.

As part of the Company's investment in customer communities, we are upgrading and strengthening the electric system to help reduce the threat of wildfire. Electric system hardening work helps reduce the risk of wildfire due to environmental factors, enhances long-term safety, especially during periods of high fire-threat, and significantly improves reliability during winter weather. We hardened 171 distribution lines in HFTD areas, replaced 706 non-exempt fuses in HFTD areas, and installed 228 new Supervisory

Control and Data Acquisition (SCADA)-enabled sectionalizing devices, enabling line reclosers serving HFTD areas. SCADA-enabled sectionalizing devices can isolate parts of the electric grid to respond to outages or emergency situations quickly, or to create a zone for microgrid operations. We also set up a test pilot resilience zone in Napa County, which is an isolated area in a community that can be energized separately during a PSPS event, to enable critical facilities to continue to be serviced.

<u>Enhanced Vegetation Management</u>: Our Enhanced Vegetation Management Program further reduces the risk of trees, limbs, and branches coming into contact with power lines in high fire-threat areas—in a more sustainable, long-term approach. We conducted Enhanced Vegetation Management inspections and further trimmed and removed vegetation along 2,498 line-miles of distribution lines in HFTD areas.

<u>Situational Awareness, Forecasting, and Support</u>: We implemented state-of-the-art technology, such as weather stations and high-definition cameras, to improve our ability to predict, monitor, and respond to extreme wildfire danger. We installed 426 weather stations and 133 high-definition cameras, developed an automated satellite fire detection and alerting system tool, and deployed Enhanced Wired Down Detection functionality to over 4.5 million SmartMeters™.

<u>Public Safety Power Shutoffs</u>: High temperatures, extreme dryness, and record-high winds have created conditions in California where any spark at the wrong time and place can lead to a major wildfire. If severe weather threatens a portion of the electric system, it is sometimes necessary for PG&E to turn off electricity in the interest of public safety. The Company is working to improve the PSPS program by making events smaller in size, shorter in length, and smarter for our customers. In the meantime, this measure of last resort is implemented to mitigate risk during the most hazardous conditions.

Extremely hazardous weather conditions occurred with unusual frequency in 2019, necessitating nine PSPS events in PG&E's service territory. This category of work includes costs associated with supporting our ability to effectively manage PSPS events and outreach to customers regarding them. We improved communication with customers, first responders, Public Safety Partners, and critical services through notifications and event specific maps. Our pre-wildfire season outreach and engagement plans were also improved by notifications throughout the 2019 PSPS events.

4. CEMA

We have included in this application the costs associated with responding to 10 different catastrophic events. In terms of CEMA cost, the largest of these events were the 2019 January/February severe storms, which damaged 9,349 units of electric equipment and caused outages for 2.3 million customers.

The second largest of these events in terms of cost was the Tubbs fire in 2017, which damaged 3,676 units of electric equipment and 36,957 gas meters were damaged or destroyed. The Tubbs fire had not been included in our prior CEMA cases because of pending investigations and litigation concerning the fire. Thus, our costs associated with the Tubbs fire appear in this application for the first time.

E. Ratemaking and Customer Impacts

On February 7, 2020, PG&E filed Application 20-02-003, which sought—on an interim basis—rate relief corresponding to many of the same costs presented for reasonableness review in this application.[9] Specifically, this interim rate relief application sought $891 million in interim rates that would be subject to refund if PG&E was unable to prove the reasonableness of that revenue requirement in the later proceedings pertaining to such costs. PG&E's request for interim rates is pending before the Commission. On September 18, 2020, the Commission issued a proposed decision that, if approved, would grant PG&E $447 million in interim rates.

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[9] The interim rate relief application sought only 85 percent of the electric distribution costs recorded in certain wildfire and catastrophic event memorandum accounts. The current application includes all LOBs (not just electric distribution) and costs from additional memorandum accounts.

This current application seeks an additional $422 million that was not sought in the interim rate relief application.[10] Our ratemaking proposals are presented below in the alternative, depending on whether our interim rate relief request is granted.

1. Preferred Scenario

PG&E's preferred scenario assumes that PG&E's interim rate request of $891 million is approved, which would leave a remaining $422.5 million (including interest of $32.9 million) revenue requirement for recovery in this application.

In this preferred scenario, PG&E proposes to recover the remaining revenue requirement over a 12-month period, following the conclusion of interim rate relief recovery starting June 2022, or as soon as practicable following a final decision. This proposal would provide rate stability while reducing the financing costs to customers.

In this scenario, the typical residential electric customer would see his/her bill increase by approximately $3.55 per month over currently effective rates. This would result in a net decrease from the level that would be authorized in interim rates. The typical residential gas customer would see his/her bill increase by approximately $0.10 per month.

2. Alternative Scenario 1

As mentioned above, the CPUC's September 18, 2020 proposed decision would provide $447.1 million of rate recovery over a 17-month period from Jan 2021 to May 2022. If the Commission adopts this proposed decision, we would propose to collect the remaining $868.4 million of revenue requirement (including interest of $34.8 million) over a 12-month period from June 2022 to May 2023, after the conclusion of interim rate relief recovery.

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[10] In our interim rate relief application, we proposed that if the Commission's reasonableness review of the underlying costs in this application did not justify the level of revenue requirement authorized in interim rate relief, we would refund to customers any over-collections with interest at the 3-month commercial paper rate. Although we do not expect this to be the case, we renew here our commitment to provide such a refund.

In this scenario, the typical residential electric customer would see his/her bill increase by approximately $7.64 per month over currently effective rates. The typical residential gas customer would see his/her bill increase by approximately $0.10 per month.

3. Alternative Scenario 2

Our alternative Scenario 2 assumes that no interim rate relief is granted, notwithstanding our request and the CPUC's recent proposed decision. In this scenario, we would propose to recover the entire $1.28 billion revenue requirement (including interest of $39.4 million) over a 24-month period, starting January 2022, or as soon as practicable following a final decision in this proceeding.

In this scenario, the typical residential electric customer would see his/her bill increase by approximately $5.82 per month over currently effective rates. The typical residential gas customer would see his/her bill increase by approximately $0.05 per month.

4. Ratemaking Mechanics

We understand that these costs represent significant increases for our customers. The significance of these costs reflects the significance and magnitude of our work in responding to the changing climate and the need to make resilient our extensive infrastructure.

To mitigate the impacts on vulnerable customers, our low-income programs like Relief for Energy Assistance through Community Help and California Alternate Rates for Energy programs are available to qualifying customers, and we will do whatever we can to lessen the impact on the most vulnerable customers.

We propose to recover all approved incremental expenditures through the Distribution Revenue Adjustment Mechanism, Portfolio Allocation Balancing Account, Core Fixed Cost Account, and Noncore Customer Class Charge Account rate mechanisms as part of the Annual Electric True-Up (AET) and Annual Gas True-Up (AGT) advice letter filings on January 1, 2022, or the next available rate change after the effective date of the decision in this proceeding, and through the AET and AGT thereafter. Rates set to recover costs in this application will be determined in the same manner as rates set to recover other Electric Distribution, Power Generation, Gas Distribution, and Gas Transmission costs, using adopted methodologies for revenue allocation and rate design. The change in rates for approved recovery of recorded costs included in this application will affect total charges for bundled service customers and for customers who purchase energy from other suppliers (e.g., direct access and community choice aggregation customers).

F. Organization of Remainder of Testimony

The remainder of the testimony in support of this application is organized as follows:

- Chapter 2 – Presents PG&E's electric distribution wildfire mitigation work recorded to the FHPMA and the FRMMA/WMPMA.
- Chapter 3 – Presents electric distribution response and recovery work recorded to CEMA.
- Chapter 4 – Presents gas distribution response and recovery work recorded to CEMA.
- Chapter 5 – Presents power generation response and recovery work recorded to CEMA, as well as power generation's work recorded to the LCPIA.
- Chapter 6 – Presents IT and other support costs recorded to the FRMMA/WMPMA.
- Chapter 7 – Presents customer care costs recorded to the RRRMA.
- Chapter 8 – Explains that the costs included in this application are incremental and not recovered elsewhere in rates.
- Chapter 9 – Describes the adjustments made to remove costs not eligible for recovery in this application.
- Chapter 10 – Describes the proposed ratemaking for the costs included in this application.

G. Conclusion

The wildfire mitigation costs we present in this application are for activities that are critically necessary to improve the safety and reliability of our system, and are consistent with the policies underlying the establishment of the FHPMA, FRMMA, and WMPMA. The CEMA costs presented in this application are for our response and restoration efforts related to 10 catastrophic events and are consistent with the requirements of Pub. Util. Code Section 454.9.

We are proud of what our employees and contractors have accomplished with this work. It has made our service area more safe for the people that live and work here.

PACIFIC GAS AND ELECTRIC COMPANY

2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS

CHAPTER 2

ELECTRIC DISTRIBUTION: WILDFIRE MITIGATION ACTIVITIES

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS
CHAPTER 2
ELECTRIC DISTRIBUTION: WILDFIRE MITIGATION ACTIVITIES

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PACIFIC GAS AND ELECTRIC COMPANY
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CHAPTER 2
ELECTRIC DISTRIBUTION: WILDFIRE MITIGATION ACTIVITIES

A. Introduction to Electric Distribution: Wildfire Mitigation Activities

This testimony supports Pacific Gas and Electric Company's (PG&E) request for authorization to recover reasonable electric distribution costs incurred for our wildfire mitigation activities through 2019. The costs requested herein were not forecasted in the 2017 General Rate Case (GRC) Application 15-09-001 (2017 GRC), but became necessary because of unfolding risks, emerging legislation, and catastrophic events in California that impacted our electric distribution system.

California has entered a "new normal" of longer and more dangerous fire seasons. Following the devastating wildfires of 2017 and 2018, lawmakers acted swiftly to address the threat of wildfires on the state's residents, environment, and economic wellbeing. Senate Bill (SB) 901[1] directed electric utilities to submit annual Wildfire Mitigation Plans to the California Public Utilities Commission (CPUC or Commission) for review. Together with SB 901, Assembly Bill (AB) 1054[2] established the mechanisms for utilities to recover the costs of implementing those plans along with certain other costs related to catastrophic wildfires, among other changes.[3]

We support state policy and recognize our vital role in reducing wildfire risk and responding to catastrophic events. To that end, we implemented an unprecedented set of programs in 2019, not contemplated in the 2017 GRC, for which we now request recovery. These programs are reflected in our 2019 Wildfire Mitigation Plan (2019 WMP), which ushered in a new era of wildfire risk focus and set aggressive goals, frontloaded to increase safety before the 2019 wildfire season and continuing to this day. The majority of the wildfire mitigation

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1 SB 901, 2017-2018 Reg. Sess. (Cal. 2018), available at: https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB901.

2 AB 1054, 2019-2020 Reg. Sess. (Cal. 2019), available at: https://openstates.org/ca/bills/20192020/AB1054/.

3 See Public Utilities Code (Pub. Util. Code) § 8386.4(a), (b)(1) and (b)(2)-(4).

costs for which we seek recovery in this application were incurred to meet the goals of the 2019 WMP, as directed by the CPUC's decision, Decision (D.) 19-05-037, approving it (2019 WMP Decision). We also seek recovery of certain other wildfire mitigation costs incurred in connection with programs approved by the CPUC prior to 2019. The tables in the "Summary of Request" subsection below reflect the specific wildfire mitigation costs for which we seek recovery.

The testimony that follows describes the measures we have already taken to reduce the risk of catastrophic wildfires in Northern California while expanding partnerships with California fire protection and public safety agencies. Though these efforts are not all new, we have ramped up our mitigation efforts significantly as Northern California's wildfire problem has appreciably grown. The programs implemented in 2019 continue to evolve as our understanding of the wildfire threat further improves, and as we learn how to maximize the effectiveness and impact of our efforts. We are grateful for the community of state and local governments, regulators, and customers who support us and share our single-minded focus on the safety of the state and its residents. We are proud of our employees and contractor partners who have taken decisive action and who continue to work tirelessly to advance this shared goal.

1. Organization of this Testimony

a. Structure of Subsections

Chapter 2 describes our specific accomplishments and requests recovery of costs incurred to implement a range of wildfire mitigations. These costs were recorded in various memorandum accounts, the history of which are detailed in the section titled "Background of Wildfire Mitigation Programs in FHPMA and WMPMA." PG&E requests recovery of wildfire mitigation costs recorded to: (1) the Fire Hazard Prevention Memorandum Account (FHPMA) through 2019; (2) the Fire Risk Mitigation Memorandum Account (FRMMA) in 2019; and (3) the Wildfire Mitigation Plan Memorandum Account (WMPMA) in 2019. This introduction summarizes the request, describes the environmental, legislative, and regulatory backdrop to these costs and corresponding memorandum accounts, and previews the specific accomplishments that will be discussed in greater detail in the Wildfire Mitigation Activities and Costs section of this chapter.

The Chapter 2 Electric Distribution: Wildfire Mitigation Activities testimony is organized as follows:

- Section A – Introduction to Electric Distribution: Wildfire Mitigation
- Section B – Wildfire Mitigation Activities and Costs
- Section B.1 – Distribution and Substation Replacements[4]
- Section B.2 – System Hardening and Other Grid Modifications
- Section B.3 – Incremental Vegetation Management
- Section B.4 – Situational Awareness, Forecasting, and Support
- Section B.5 – Public Safety Power Shutoffs
- Section C – Conclusion

b. Presentation of Costs

Chapter 2 is organized by wildfire mitigation program. Costs of each program are presented with information about the associated memorandum account and the breakdown of capital and expense. The level of supporting detail provided depends upon the complexity of the program and the magnitude of the request. Because the wildfire mitigation programs implemented in 2019 were approved in the 2019 WMP, we use the term "WMPMA" in this chapter to refer to both the FRMMA and WMPMA. All chapter 2 costs tables are 2019 WMPMA costs unless otherwise noted. Additional program information, including planning order details for all costs, can be found in the workpapers supporting Electric Distribution.

On May 7, 2020, the Commission issued D.20-05-019 (Wildfire Order Instituting Investigation, Decision Approving Proposed Settlement Agreement with Modifications), referred to herein as the "Wildfire OII Decision," to resolve issues concerning the role of PG&E's electric facilities in igniting wildfires in our service territory in 2017 and 2018. The Wildfire OII Decision imposes penalties totaling $2.137 billion, of

4 Because of the Wildfire OII Decision, only replacement costs are being sought in what is otherwise recognized as our "Enhanced Inspections, Repairs, and Replacements" program; Section B.1 has been renamed to "Distribution and Substation Replacements" to reflect that our request is for replacement costs only.

which $1.823 billion is in disallowances for wildfire-related expenditures. As a result of the Wildfire OII Decision disallowances, the amount of costs we actually incurred for the activities described in this filing are greater than the amount of recovery requested.[5]

2. Summary of Request

In this chapter, PG&E requests authorization to recover the following amounts: $295 million in wildfire mitigation costs recorded to the FHPMA between 2012 and 2019; and $1,289 billion in wildfire mitigation costs recorded to the WMPMA in 2019. Tables 2-1 and 2-2 present these costs by mitigation program for the FHPMA and WMPMA, respectively, and reflect the Electric Distribution (which includes Shared Services and Corporate Services) portion of the costs and adjustments to the FHPMA and WMPMA in Table 9-1 less the Ernst & Young recommendations, Overhead Cost Variance adjustment, and AB 1054 adjustment.

TABLE 2-1
2012-2019 FHPMA-ELIGIBLE ELECTRIC DISTRIBUTION EXPENDITURES AND VEGETATION MANAGEMENT
(THOUSANDS OF DOLLARS)

Line No.	Program	Capital	Expense
1	Incremental Vegetation Management	–	$295,036

5 D.20-05-019, p. 35; $157 million disallowance for Distribution Safety Inspections Expense (excludes repairs) FRMMA/WMPMA; $79 million Distribution Safety Repairs Expense FRMMA/WMPMA; $36 million Accelerated Wildfire Risk Reduction Base Camp and Admin Expense FHPMA.

TABLE 2-2
2019 WMPMA-ELIGIBLE ELECTRIC DISTRIBUTION EXPENDITURES
WILDFIRE MITIGATION PROGRAMS
(THOUSANDS OF DOLLARS)

Line No.	Program	Capital	Expense	Total
1	Distribution and Substation Replacements	$220,445	$7,280	$227,726
2	System Hardening and Other Grid Modifications	337,989	–	337,989
3	Incremental Vegetation Management	–	449,502	449,502
4	Situational Awareness, Forecasting and Support	14,159	44,690	58,850
5	Public Safety Power Shutoffs	1,732	212,478	214,210
6	Total	$574,325	$713,950	$1,288,276

3. Background of Wildfire Mitigation Programs in FHPMA and WMPMA

a. Climate Change and Increased Catastrophic Wildfires

California has experienced dramatic environmental changes in recent years, including extremely strong wind events, unprecedented tree mortality, record rainfall, heat waves, and drought. As a result, the frequency and scope of wildfires in California has also increased substantially. In 2017 alone, California experienced five of the 20 most destructive fires in its history up to that point in time. In November 2018, California experienced two more devastating fires—the Camp Fire in Northern California and the Woolsey Fire in Southern California. The Camp Fire is now considered the most destructive wildfire in California history, with over 80 fatalities and extensive property destruction.

A number of climate-related factors have contributed to the increasing risk of wildfires. For example, bark beetles and drought have contributed to record numbers of dead trees that fuel and amplify wildfires.[6] According to the United States Forest Service (USFS), approximately 163 million trees have died in California since 2010.[7] Moreover, as air temperatures rise, forests and land are drying out,

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6 Assembly Floor Analysis, issued August 28, 2018, at p. 5, available at: http://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201720180SB901 (accessed October 2, 2018).

7 https://www.fs.fed.us/rm/pubs_journals/2019/rmrs_2019_axelson_j001.pdf.

increasing fire risks and creating weather conditions that readily facilitate the rapid expansion of fires.[8]

The Fourth National Climate Assessment was issued in November 2018 as mandated by the United States Congress in the Global Change Research Act of 1990. The Climate Science Special Report, issued as part of that assessment, found that "the incidence of large forest fires in the western United States and Alaska has increased since the early 1980s and is projected to further increase in those regions as the climate warms, with profound changes to certain ecosystems."[9]

The Fourth National Climate Assessment further concluded that,

> [W]ildfire trends in the western United States are influenced by rising temperatures and changing precipitation patterns, pest populations, and land management practices. As humans have moved closer to forestlands, increased fire suppression practices have reduced natural fires and led to denser vegetation, resulting in fires that are larger and more damaging when they do occur (Figures 1.5 and 1.2k) (Ch. 6: Forests, KM 1). Warmer winters have led to increased pest outbreaks and significant tree kills, with varying feedbacks on wildfire. Increased wildfire driven by climate change is projected to increase costs associated with health effects, loss of homes and other property, wildfire response, and fuel management.[10]

Similarly, the CPUC recognized in December 2019 that "California is experiencing an increase in wildfire events due to a number of factors, including an extended period of drought, upwards of 10 years, increased fuel for fires, and unprecedented conditions that are leading to extreme weather events."[11]

Former governor Jerry Brown has dubbed California's "new normal" with regard to the risk, magnitude, and devastating impact of wildfires as

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8 The Atlantic, Why the Wildfires of 2018 Have Been So Ferocious, (August 10, 2018).

9 United States (U.S.) Global Change Research Program, *Climate Science Special Report: Droughts, Floods, and Wildfire*, Chapter 8 (2017).

10 U.S. Global Change Research Program, Fourth National Climate Assessment, Volume 2.

11 Order *Instituting Rulemaking to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions*, R.18-12-005, p. 1 (Dec. 19, 2019).

a “new *abnormal*” that will continue over the next 20 years.[12] As part of this new abnormal, wildfire season—when the risk of wildfire is much greater—could span more than eight months of every year.

The 2020 wildfire season has already been unprecedented, with unusual weather patterns (like a summer dry lightning storm) driving record setting wildfires that had burned millions of acres before the start of September. On September 11, 2020, Governor Gavin Newsom declared that “We’re in the midst of a climate Emergency.”[13]

Yet, even as wildfire risks increase, they are not uniform throughout California. PG&E faces particular challenges in mitigating wildfires due to the size and geography of our service area. Our service area is approximately 70,000 square miles and contains substantially more High Fire-Threat District (HFTD) areas than the service territories of the two other large electric California Investor-Owned Utilities (IOU) combined. As shown in Figure 2-1 below, according to the United States Forest Service, the majority of high-density forest area in California is in Northern California.

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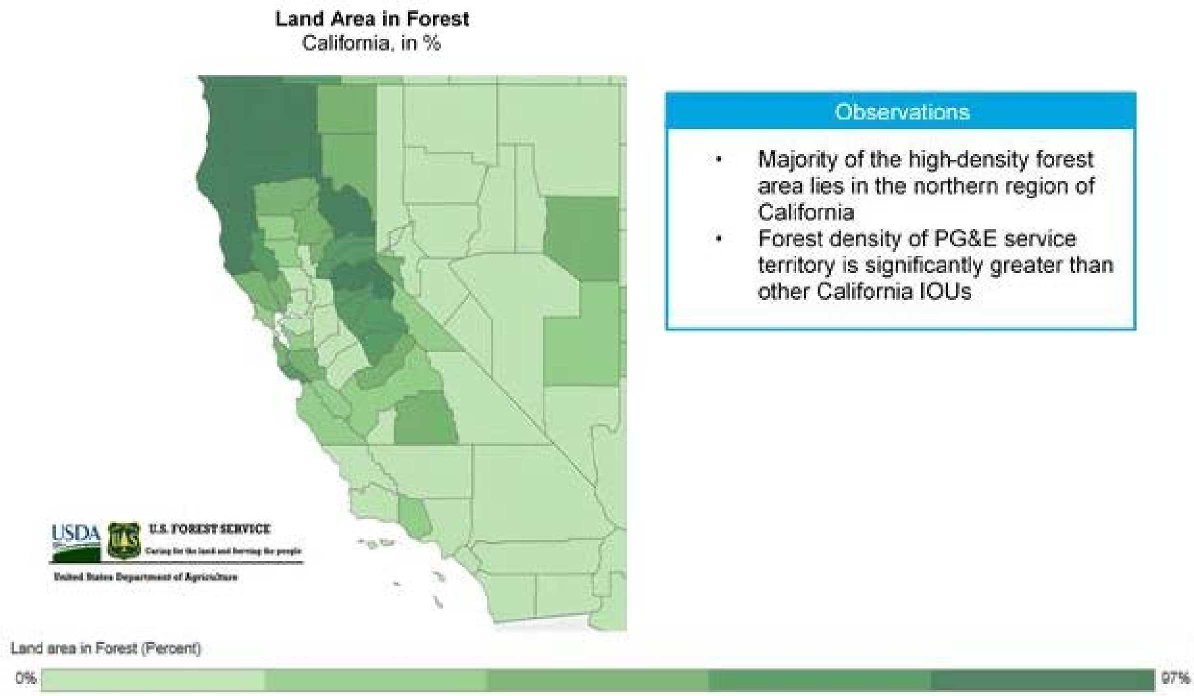
12 Los Angeles Times, Gov. Brown: Mega-fires ‘the new abnormal’ for California, (November 11, 2018).

13 The Sacramento Bee, September 11, 2020 available at: https://nam01.safelinks.protection.outlook.com/?url=https%3A%2F%2Fwww.sacbee.com%2Fnews%2Fpolitics-government%2Fcapitol-alert%2Farticle245667580.html&data=02%7C01%7Csgw1%40pge.com%7Cac671f04969f413e4d2408d8578ec433%7C44ae661aece641aabc967c2c85a08941%7C0%7C0%7C637355617998933665&sdata=0cbg3JsmK95KPWLC6nbF7cmXzv3TW2uxkkl0xsGds%2FM%3D&reserved=0.

FIGURE 2-1
HIGH DENSITY FOREST AREA IN NORTHERN CALIFORNIA



Note Source: USDA Forest Service, 2017 RPA data.

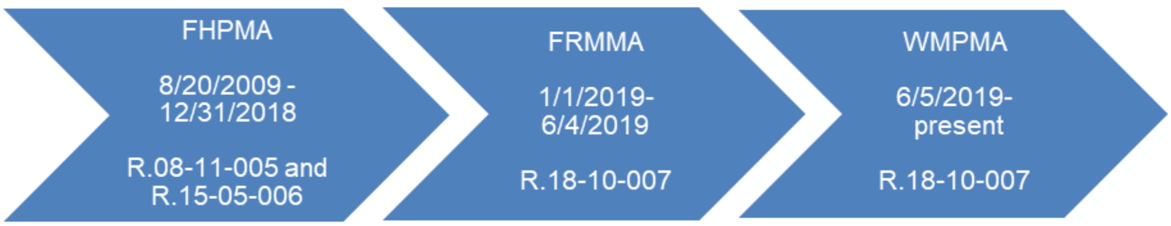
Our service area also has more overhead distribution circuit miles that traverse HFTD areas than the other two California IOUs combined. Approximately 65 percent of California IOUs' overhead distribution line-miles located in Tier 2 and Tier 3 HFTD areas are within our service area. We estimate that at least 100 million trees adjacent to our overhead power lines have the potential to either grow into, or fall into, the lines.

These extraordinary conditions have led to an era of unprecedented wildfire threats and events, requiring California's local and state governments, regulators, and utilities to take decisive action to mitigate wildfire risks related to electric utility infrastructure.

b. Regulatory and Legislative Background

The past decade has seen several legislative and regulatory actions aimed at reducing the risk of wildfire stemming from electric utility infrastructure. This subsection provides a summary of those actions significant to this request, along with the history of the FHPMA, FRMMA, and WMPMA memorandum accounts that track the costs for which recovery is sought herein. The effective periods and Orders Instituting Rulemaking (OIRs) for these memorandum accounts are reflected in Figure 2-2 below.

FIGURE 2-2
EFFECTIVE PERIODS AND OIRS FOR WILDFIRE MITIGATION MEMORANDUM ACCOUNTS



1) CPUC Decisions Establishing the FHPMA and HFTD Areas

In 2008, the CPUC issued Order Instituting Rulemaking (R.) 08-11-005 to revise and clarify Commission regulations relating to the safety of electric utility facilities. Beginning in 2009, the CPUC issued several decisions in that proceeding resulting in the adoption of dozens of new fire-safety regulations and the establishment of a memorandum account for electric utilities to record related costs.

In the Phase 1 Decision, D.09-08-026, the CPUC adopted measures to reduce fire hazards in California and established the FHPMA for electric utilities to record related costs. PG&E filed Advice Letter 3523-E on September 10, 2009 to establish the FHPMA in compliance with Ordering Paragraph 7 of D.09-08-029. The Advice Letter was approved on October 5, 2009, and the FHPMA became effective on August 20, 2009.

The Phase 2 Decision, D.12-01-032, modified General Order 95[14] and General Order 165,[15] and, along with other orders, directed utilities to put forth a Fire Prevention Plan. In D.14-01-010, the CPUC approved the development and use of fire hazard maps as a permanent replacement for several maps that had been adopted on an interim basis.

On May 7, 2015, the Commission opened R.15-05-006 to develop and adopt fire-threat maps and fire safety regulations, and closed R.08-11-005. The Commission reaffirmed in Ordering Paragraph 9 of the adopted order that electric IOUs shall continue to track and record their costs to implement the regulations adopted in R.15-05-006 in the FHPMA established pursuant to the Phase 1 Decision (D.09-08-026), and consistent with guidelines set forth in the Phase 2 Decision (D.12-01-032) of R.08-11-005.[16] PG&E filed Advice Letter 4669-E on July 16, 2015 to update the existing FHPMA in compliance with Ordering Paragraph 9 of R.15-05-006. The CPUC approved Advice Letter 4669-E on August 24, 2015, effective May 7, 2015.

Taken together, R.08-11-005 and R.15-05-006 allow PG&E to recover reasonable costs recorded to the FHPMA. The procedure for doing so is set forth in Ordering Paragraph 14 of the Phase 2 Decision (D.12-01-032), which provides that an electric IOU may, in its discretion, file one or more applications to recover the costs

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14 General Order 95 establishes requirements for the design, construction, and maintenance of overhead electric lines to ensure adequate service and safety to persons engaged in the construction, maintenance, operation and use of overhead lines and to the general public.

15 General Order 165 establishes requirements for inspections of electric distribution and transmission facilities to ensure safe and high-quality electric service.

16 Ordering Paragraph 9 of R.15-05-006 provides, “Electric IOUs may record their payments in their FHPMA that are described in D.12-01-032 at 153-156.”

recorded in its FHPMA.[17] With this application, PG&E is requesting recovery of the balance of costs recorded to the FHPMA between 2012 and 2019. Costs are no longer being recorded in the FHPMA, and the FHPMA will be closed following a decision in this proceeding.

In addition to affirming cost recovery mechanisms, the scope of R.15-05-006 included the development and adoption of a statewide fire-threat map delineating the boundaries of High Fire-Threat Districts, in which new and previously adopted fire-safety regulations would apply. On December 21, 2017, the CPUC issued D.17-12-024, which amended General Order 95 to include stricter fire-safety regulations applicable to HFTD areas. On January 19, 2018, the CPUC adopted the final CPUC Fire-Threat Map[18] via the Safety and Enforcement Division's disposition of a Tier 1 Advice Letter.[19] As shown in Figure 2-3 below, the CPUC Fire-Threat Map is the basis for the HFTD Map, where the stricter fire-safety regulations apply. The HFTD Map provides the initial geographic prioritization for the activities in PG&E's 2019 WMP, for which recovery of reasonable incremental costs is sought in this application.

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17 D.12-01-032 Ordering Paragraph 14: The electric IOU may continue to record authorized costs in its FHPMA until the first GRC that occurs after the close of the new proceeding (R.15-05-006) or subsequent successor proceedings, at which time the FHPMA shall be closed. The electric IOU may then use the GRC mechanism to request recovery of the costs it incurs from that point forward to comply with the regulations adopted in R.08-11-005, R.15-05-006, and any subsequent proceedings. The electric IOU may seek to recover the ending balance in its FHPMA, if any, by filing an application.

18 The CPUC Fire-Threat Map can be viewed here: ftp://ftp.cpuc.ca.gov/safety/fire-threat_map/2018/PrintablePDFs/8.5X11inch_PDF/CPUC_Fire-Threat_Map_final.pdf.

19 Advice Letter 5211-E/3172-E.

FIGURE 2-3
CPUC MAP EVOLUTION

Table 2-3 below summarizes the characteristics of the Tier 2, Tier 3, and Zone 1 areas included in the January 2018 HFTD Map:

TABLE 2-3
CPUC HFTD MAP TIER DEFINITIONS

Line No.	Tier Level	Definition	Distinctions
1	HFTD Tier 3 – Extreme Risk	Extreme risk (including likelihood and potential impacts of occurrence) for utility associated wildfires.	Tier 3 is distinguished from Tier 2 by having highest likelihood of fire initiation and growth that would impact people or property from utility associated fires, and where the most restrictive utility regulations are necessary to reduce utility fire risk.
2	HFTD Tier 2 – Elevated Risk	Elevated risk (including likelihood and potential impacts of occurrence) for utility associated wildfires.	Tier 2 is distinguished from Zone 1 and other areas outside the HFTD by having greater likelihood of fire initiation and growth that would impact people or property, from utility associated wildfires, and where enhanced utility regulation could be expected to reduce utility fire risk.
3	HFTD Zone 1 – High Hazard Zones	High Hazard Zones (HHZ) on the USFS CAL FIRE Joint Map of Tree Mortality HHZs, excluding areas in Tier 3 or Tier 2. These are areas where tree mortality directly coincides with critical infrastructure. They represent direct threats.	Zone 1 is defined as a Tree Mortality HHZ (as determined by California's Tree Mortality Task Force), a subset of Tier 1 of the CPUC HFTD Map. Zone 1 excludes areas in the Elevated Risk of Tier Level 2, and the Extreme Risk of Tier Level 3 risk areas but is included in the HFTD due to specific hazards to utilities.

In accordance with D.12-01-032, PG&E requests recovery of $295 million recorded to the FHPMA between 2012 and 2019. These costs reflect new wildfire mitigation programs, developed at the direction of the CPUC, that exceed the scope of the 2011, 2014, and 2017 GRCs.

1) SB 901
2) AB 1054
3) FRMMA
4) WMPMA

Following multiple catastrophic wildfires in 2017 and 2018, California enacted SB 901 on September 21, 2018. Effective January 1, 2019, the bill set in motion a series of activities to strengthen California's ability to prevent and recover from catastrophic wildfires. Among other measures, SB 901 mandated additional requirements for utility operations, maintenance, and infrastructure, including a requirement that electric IOUs with lines or equipment in HFTD areas annually submit a comprehensive Wildfire Mitigation Plan (WMP) to the CPUC. SB 901 prescribed specific requirements for these annual plans, including the timing and process for cost recovery.[20] The bill also established two memorandum accounts for electric utilities to record costs incurred to implement their plans. One such memorandum account, the FRMMA, is intended to "track costs incurred for fire risk mitigation that are not otherwise covered in the electrical corporation's revenue requirement."[21] The second memorandum account, the WMPMA, is established upon approval of a utility's WMP and used "to track costs incurred to implement the plan."

The Commission opened R.18-10-007 on October 25, 2018 to implement the provisions of SB 901. On November 1, 2018, PG&E submitted Advice Letter 5419-E to establish the FRMMA to track costs incurred for fire risk reduction that are not otherwise encompassed in our revenue requirement. The Commission approved Advice Letter 5419-E on March 12, 2019, effective January 1, 2019.

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20 Pub. Util. Code § 8386 (c) (effective Jan. 1, 2019).

21 Pub. Util. Code § 8386 (j) (effective Jan. 1, 2019).

We submitted our first ever WMP on February 6, 2019 (the 2019 WMP), which the Commission approved on May 30, 2019 in D.19-05-037. In Ordering Paragraph 21, D.19-05-037 authorized PG&E to open the WMPMA to track incremental wildfire-related costs incurred while implementing approved programs within the 2019 WMP. On June 5, 2019, we submitted Advice Letter 5555-E to establish the WMPMA. The Advice Letter was approved by the Commission on August 8, 2019 with an effective date of June 5, 2019.

Accordingly, costs PG&E incurred prior to June 5, 2019 to implement activities approved in D.19-05-037 are tracked in the FRMMA, while costs incurred as of June 5, 2019 are tracked in the WMPMA. Because the intent of both memorandum accounts is the same—to record 2019 costs incremental to the GRC, we use "WMPMA" throughout this chapter for costs recorded to either the FRMMA or WMPMA, regardless of when in 2019 the cost was incurred.

AB 1054, enacted July 12, 2019, established mechanisms for electric utilities to recover the costs of implementing their wildfire mitigation plans. The bill requires the Commission to authorize cost recovery if the costs and expenses are determined to reflect just and reasonable conduct by the electric corporation. AB 1054 also established a "Wildfire Fund" available to IOUs that satisfy certain requirements and created the Wildfire Safety Advisory Board and Wildfire Safety Division within the CPUC.

In accordance with SB 901 and AB 1054, by way of this application, PG&E requests recovery of $1.289 billion recorded to the WMPMA in 2019. These costs are associated with existing programs that were expanded in the 2019 WMP and therefore exceed the scope of the 2017 GRC, as well as new programs that were first presented in the 2019 WMP.

4. Accomplishments

Our primary responsibility is ensuring the safety of the customers and communities we serve by providing safe and reliable natural gas and electricity. We responded to the devastation of Northern California's 2017 and 2018 wildfire seasons by implementing a nationally unprecedented wildfire safety program, which was approved by the CPUC. The 2019 WMP set aggressive goals for inspecting, repairing, hardening, and modernizing PG&E's electric distribution system on an accelerated basis to decrease wildfire risks and increase safety in advance of the 2019 wildfire season.

Due to the urgency and sheer scope of the 2019 WMP, significant national outreach was necessary to mobilize enough human resources to complete the work across Northern California. To meet commitments, we had to quickly obtain resources like tree trimmers, inspectors, and linemen on an extraordinary scale in 2019. Likewise, high demand for certain materials in advance of the 2019 wildfire season challenged traditional utility supply chains. The weather in 2019 added to the challenges, including a record nine events that met conditions calling for PSPS in PG&E's service territory. As PG&E and other utilities worked toward unparalleled wildfire mitigation goals, regulators and lawmakers, applying lessons learned throughout the state, made adjustments and guided course corrections to benefit all of California. Taken together, the challenges of sourcing the wildfire mitigation efforts, standing up new programs in real time, and responding to changing policy, provide the backdrop for how PG&E's wildfire mitigation efforts unfolded in 2019.

Despite the challenges, we met and even exceeded the goals of the 2019 WMP in partnership with state and local governments, regulators, contractors, and customers. We tested and deployed new technologies, expanded our vegetation management programs, enhanced our operational practices, and upgraded our situational awareness capabilities, among other accomplishments. A summary of high-level accomplishments is provided in Table 2-4, followed by an overview of the major initiatives. The summary and overview include accomplishments that we have excluded from our recovery request on account of the Wildfire OII Decision. Accordingly, the units described here may differ from those presented in the "Wildfire Mitigation Activities and Costs" section of this chapter.

TABLE 2-4
SUMMARY OF ACCOMPLISHMENTS
2019 WMPMA AND WILDFIRE MITIGATION ACTIVITIES

2019 Incremental WF Mitigation Program Accomplishments		
Activity	**Accomplishments**	**Notes**
Enhanced Wildfire Inspections and Repairs (Section B.1, Distribution and Substation Replacements)		
Asset Inspection and Repair/Replacements	Distribution – 694,250 poles	Identify and repair actual and potential equipment problems that could contribute to a failure or wildfire ignition. All structures in HFTD inspected in 2019 and late 2018
	Substations – 222	
	Distribution – repaired 4,881 A&B tags	Repaired all A tags and 94 percent of B tags identified through 2019 inspections.
	Substations – repaired 745 A&B tags	
	Substation Defensible Space Clearing – 186	Assessed the area around substations in HFTD areas to ensure a safe distance, or defensible space, between trees and/or vegetation and critical infrastructure.
	Substation Animal Abatement Replacements – 19	Install new equipment or retrofit existing equipment with protection measures intended to reduce animal contacts.
System Hardening and Other Grid Modifications (Section B.2)		
Miles Hardened	171 line-miles	Replace or eliminate overhead distribution lines in high-risk areas with stronger, more resilient equipment. 'Hardening includes replacing bare overhead conductor by (1) eliminating the line entirely, (2) undergrounding or (3) replacing with covered conductor and stronger poles.
Reclosers	Supervisory Control and Data Acquisition (SCADA)-enabled all remaining (287) manual reclosers	SCADA-enabled recloser allows remote control to prevent a line from reenergizing after a fault
Automated Sectionalization	298 devices	Enable remote control and automated operation of field equipment to more precisely deenergize sections of the grid when fire risk is high. Sectionalization devices enable separating the distribution grid into smaller sections for greater operational flexibility.
Distributed Generation and Microgrids	Completed 1 temporary microgrid pilot. Operated 3 additional temporary microgrids during 2019 PSPS events.	Operating temporary microgrids also referred to as resilience zones, can reduce the number of customers de energized during a PSPS event, as well as energize shared community resources.
Incremental Vegetation Management (Section B.3)		
Enhanced VM (EVM)	2,498 line-miles	VM and tree clearing reduce fire risk by reducing potential vegetation contacts with utility equipment. EVM activities are in addition to PG&E's routine VM practices.
Situational Awareness, Forecasting, and Support Programs (Section B.4)		
Weather Stations	426 installed	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. These tools enable better real-time monitoring of high-risk fire areas and conditions; all data feeds are shared publicly at pge.com/weather.
High-Def Cameras	133 installed	
Wildfire Risk Identification	Implemented 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.	Leverage better situational awareness and analytical capability to identify and respond to fire threats more effectively
Faster Power Restoration	PSPS Restoration target of 24 daylight hours from weather "all clear" to power restored, generally achieved	Shorter outages, through increased operational tools and improved processes, will reduce burden of PSPS events on customers and communities. Faster power restoration to reduce the degree of customer and community disruption from an outage.
Meteorology	Weather forecasted at 3 km X 3 km resolution. Updated weather impact models, datasets & improved meteorology computing power.	Tighter geographic understanding of weather and fire risk allows more accurate design of PSPS need and scope. 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.

TABLE 2-4
SUMMARY OF ACCOMPLISHMENTS
2019 WMPMA AND WILDFIRE MITIGATION ACTIVITIES
(CONTINUED)

2019 Incremental WF Mitigation Program Accomplishments		
Activity	**Accomplishments**	**Notes**
Public Safety Power Shutoffs (Section B.5)		
PSPS Events	9 PSPS outages lasting from ~14 to 55 hours (on average for all affected customers)	Shutting off power in high-risk fire areas under high-risk weather conditions prevents utility equipment from igniting a potentially catastrophic fire. Particularly working to reduce PSPS impacts on communities forecast to be most frequently affected by PSPS events.
Community Resource Centers (CRC)	Established 70+ temporary CRCs during a single late October / early November 2019 PSPS event	Lessen the Burden of PSPS Outages by Increasing Customer and Community Coordination, Information, Preparation and Services Before and During Outages
Communication and Outreach	Community outreach program included hosting 23 open houses plus 3 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	
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	

Note: Table 2-4 provides a sample of PG&E's 2019 accomplishments. Further details are found in the section titled "Wildfire Mitigation Activities and Costs."

a. Distribution and Substation Replacements

In the 2019 WMP, we created the Wildfire Safety Inspection Program (WSIP) to enhance and prioritize inspections of electrical equipment located in HFTD areas. In 2019, as part of the WSIP, we inspected 694,250 poles in HFTD areas to identify and replace poles and equipment that were damaged, degraded, or posed a risk of failing and causing a fire. Common maintenance conditions requiring replacement or removal include broken and/or damaged conductor, connectors, crossarms, insulators, and deteriorated, damaged, or deformed poles. In 2019, PG&E completed repair and replacement work on 4,881 priority A & B "Electric Corrective" (EC) tags. The distribution line system replacement work is an integral part of ensuring that pole and equipment weaknesses identified during WSIP inspections are addressed in a timely and efficient manner. Preventing the failure of HFTD overhead assets is essential for reducing the chances of wildfire ignition.

In addition to the enhanced inspections and replacements on the distribution system, we completed inspections of 222 distribution substation locations and performed several mitigation activities, including defensible space, animal abatement, and “just-in-time” replacements. In 2019, we conducted defensible space clearing of vegetation and other combustible material around 186 distribution substations within HFTD areas. In addition, we performed animal abatement replacements on 19 substations in 2019, which involved installing new equipment or retrofitting existing equipment with protection measures intended to reduce animal contacts. Finally, in 2019, we performed equipment replacements for four substation assets that were analyzed and determined to be deteriorated to a point where repairs were no longer economically feasible, referred to as just-in-time replacement.

Costs associated with our 2019 distribution line system and substation replacement work are recorded to the WMPMA and described further in the section titled “Distribution and Substation Replacements.”

b. System Hardening and Other Grid Modifications

System hardening entails eliminating certain overhead distribution lines in HFTD areas or replacing them 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, undergrounding lines, or completely eliminating overhead assets. In 2019, we completed hardening for 171 distribution line miles in HFTD areas.

We also created a program to replace non-exempt fuses and cutouts with exempt equipment that is “non-expulsion,” meaning it does not generate arcs or sparks during normal operation. In 2019, we replaced 706 non-exempt fuses in HFTD areas, exceeding the 2019 WP target by 81 fuses.

System automation is another important tool to prevent and mitigate fires associated with utility equipment. We use Supervisory Control and Data Acquisition (SCADA) enabled reclosers and sectionalization devices to allow operators to keep lines out of service to prevent ignitions under hazardous conditions. These devices enable de-energization and reenergization of smaller, more precise sections of the grid with higher speed, enabled by remote operation and automation. SCADA-enabled reclosers have been installed in place of manual devices to allow system operators to remotely prevent a line from automatically re-energizing (reclosing) after a fault.

In 2019, we installed 298 automated sectionalization devices including 228 new SCADA enabled sectionalizing devices to SCADA enable 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.

The installation of microgrids, also referred to as resilience zones, can reduce the number of customers de-energized during a PSPS event, as well as provide additional impact mitigation by energizing shared community resources that support the surrounding population. In 2019, we operationalized one resilience zone[22] to evaluate its performance and effectiveness and incorporate lessons learned into future resilience zones.

Additional details about our System Hardening and Other Grid Modifications activities are provided in the section titled “System Hardening and Other Grid Modifications.”

c. Incremental Vegetation Management

When vegetation comes into contact with electrical equipment, the equipment can spark and cause fires. Trimming vegetation and removing dead trees also reduces the amount of fuel that can start or spread a fire, regardless of the cause of the ignition. In addition to our Routine Vegetation Management work,[23] we have initiated several Incremental Vegetation Management programs to reduce wildfire risks from vegetation interacting with powerlines. In 2019, PG&E’s Enhanced

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[22] Angwin Resilience Zone in Napa County.

[23] PG&E’s Routine Vegetation Management program is funded through the General Rate Case and 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.

Vegetation Management Program inspected and further trimmed or removed vegetation along 2,498 line-miles (approximately 10 percent) of distribution lines within HFTD areas. These measures reduce the likelihood of future ignitions caused by contact between vegetation and lines, as well as the amount of fuel available to spread a fire. Costs associated with the Incremental Vegetation Management programs are recorded to the FHPMA and WMPMA and described further in the section titled "Incremental Vegetation Management."

d. Situational Awareness, Forecasting, and Support Programs

To increase situational awareness, we are installing a number of weather and fire monitoring devices throughout 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.

We implemented a variety of situational awareness tools in the HFTD areas in 2019. For example, we:

- Installed and operationalized 426 weather stations;
- Installed 133 high-definition cameras;
- Deployed SmartMeter™ Partial Voltage Detection functionality to approximately 4.5 million SmartMeters;
- Deployed an automated satellite fire detection and alerting system tool; and
- Configured access to multiple external real-time weather service feeds.

Each of these technologies is used to track real-time fire conditions and create highly localized weather and fire risk forecasts, which can flag high-risk locations and system conditions. We share this information with government agencies and first responders and use it internally to inform decisions to activate field crews and operational measures necessary to prevent outages and respond to incidents.

We also operated a Wildfire Safety Operations Center (WSOC) to monitor, assess, and direct wildfire prevention and response efforts, and the Community Wildfire Safety Program (CWISP) Program Management

Office (PMO) to coordinate and track implementation of wildfire mitigation activities. Costs to implement enhanced Situational Awareness, Forecasting, and Support Programs are recorded to the WMPMA and described further in the section titled “Situational Awareness, Forecasting and Support.”

e. Public Safety Power Shutoffs

In 2018, the CPUC ordered utilities to present plans and protocols to deenergize portions of their electric distribution systems in the interest of public safely.[24] Significant wildfires are most likely to occur under the highest-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 our distribution and transmission assets are located. Under extremely high-risk conditions, it is necessary to deenergize some transmission or distribution lines to reduce the risk of equipment failures or vegetation or other items contacting live wires.

Extremely hazardous weather conditions were particularly frequent during the 2019 fire season, forcing PG&E to conduct nine PSPS events. In 2019, we improved strategies to minimize the extent of PSPS disruption, including back-up generation and Community Resource Centers. We identified areas of low wildfire risk that could be isolated from adjacent Tier 2 and Tier 3 areas and began implementing system hardening and sectionalizing strategies to reduce the impact to customers in those areas.

During the 2019 PSPS events, we implemented enhanced notifications and event-specific maps to communicate with customers, first responders, public safety partners, and critical services. Proactive, pre-wildfire season outreach and engagement plans helped prepare customers and communities for PSPS events.

Costs to implement PSPS are recorded to the WMPMA and described further in the section titled “Public Safety Power Shutoffs.”

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24 R.18-10-007, December 17, 2018; Assigned Commissioner’s Scoping Memo and Ruling, Appendix A (6).

B. Wildfire Mitigation Activities and Costs

1. Distribution and Substation Replacements

As part of the Wildfire Safety Inspection Program (WSIP), we inspected 694,250 poles and 222 substations in HFTD areas within our service territory to identify and replace distribution and substation equipment that were damaged, degraded, or posed a risk of failing and causing a fire. In 2019, we began the replacement and substation mitigation work to address these issues to mitigate potential wildfire risk.

This section discusses two activities, Distribution Line System Replacements and Substation System Mitigations, as shown in Table 2-5 below.

TABLE 2-5
SUMMARY OF DISTRIBUTION AND SUBSTATION REPLACEMENTS COSTS
(THOUSANDS OF DOLLARS)

Line No.	Activity	MAT	Capital	Expense
1	Distribution Line System Replacements	07D, 07O 17B, 2AA, 2AB, 2AF	$211,029	–
2	Substation System Mitigations	59F, IG#	9,416	7,278
3	Total – Distribution and Substation Replacements	–	$220,445	$7,278

Each of these activities is discussed in detail below.

a. Distribution Line System Replacements

TABLE 2-6
SUMMARY OF DISTRIBUTION LINE SYSTEM REPLACEMENTS 2019 COSTS
(THOUSANDS OF DOLLARS)

Line No.	Activity	MAT	Capital	Expense
1	Overhead Non-Pole Replacement	2AA	$107,192	–
2	Deteriorated Pole Replacements	07D, 07O	99,107	–
3	Routine Emergency Replacement	17B	3,788	–
4	Idle Facilities Removal	2AB, 2AF	942	–
5	Total – Distribution Replacements	–	$211,029	–

1) Background – Wildfire Safety Inspection Program (WSIP) Inspection and Repairs (Excluded from Request)

As a part of our routine preventative maintenance, we regularly inspect distribution line equipment to identify safety issues and potential areas of deterioration that could create unsafe situations or cause outages. Among the mitigation measures implemented as part of our 2019 WMP, the Wildfire Safety Inspection Program (WSIP) called for enhanced inspections in newly-defined HFTD areas to proactively identify and address potential equipment deficiencies. We began conducting these inspections on an accelerated basis in 2019 to mitigate the ignition risk posed by our equipment in advance of the wildfire season.

In contrast to our routine inspection program, which continued for non-HFTD areas, the enhanced inspection program was developed using a risk-informed approach to proactively identify and address threats to safety and reliability. We created an enhanced inspection checklist for the WSIP that focused on wildfire specific elements. In addition, due to the importance of the WSIP inspections, we expanded documentation requirements to reflect the current status of all equipment conditions observed in the field, as opposed to only those conditions determined to be sub-standard. The enhanced inspection documentation included over 50 checklist items such as the following:

1. *Is Crossarm damaged, broken, burnt, decayed, rotten, loose, missing hardware, or showing signs of bent bolts/brackets, gun shots, insect damage, woodpecker damage or splitting that compromises integrity of the crossarm; and*
2. *Has dead or dying trees/vines made contact with the pole, equipment, and its associated spans and/or could make contact with the pole, equipment, and its associated spans?*

We completed a total of 694,250 WSIP inspections and 11,829 distribution line equipment repairs in the first year of the program. Repair work included overhead repairs for equipment that was broken, damaged, or decayed, and routine emergency repairs for equipment whose condition posed an imminent risk of failure.

Pursuant to the settlement agreement submitted in connection with the Wildfire OII Decision, I.19-06-015 (the Wildfire OII Decision), we are not seeking recovery of costs associated with the 2019 WSIP inspections or repair work in this application. We only seek recovery of 2019 costs associated with WSIP equipment replacement work, which is described in the remainder of this section.

2) Nature of Activity

When a WSIP inspector identified a condition requiring corrective action under GO 95 and GO 165 (as those standards were amended by the 2017 High Fire-Threat District (HFTD) Fire Safety Decision D.17-12-024), the inspector recorded the deficiency and completed an initial Electric Corrective (EC) notification/tag indicating the urgency of the condition. Common maintenance conditions requiring replacement or removal include broken and/or damaged conductor, connectors, crossarms, insulators, and deteriorated, damaged, or deformed poles.

The corrective work performed in 2019 for which we seek recovery in this application included the following:

a) Overhead Non-Pole Replacement

Overhead non-pole replacement refers to the identification and replacement of broken, damaged, or decayed overhead distribution equipment. The main types of overhead equipment replaced during our 2019 WSIP were conductors, connectors, crossarms, insulators, and transformers.

FIGURE 2-4
PRIMARY CONDUCTOR DAMAGE
(CONDUCTOR TEARING APART)

FIGURE 2-5
BURNT CONDUCTOR

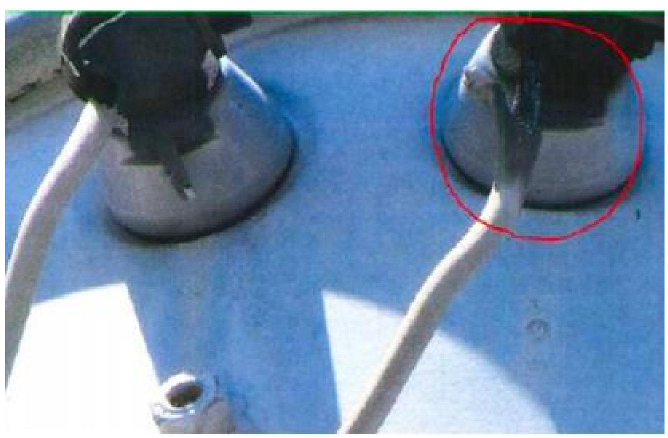

FIGURE 2-6
DAMAGED INSULATOR

b) Deteriorated Pole Replacement

Deteriorated pole replacement refers to the identification and replacement of deteriorated wood distribution poles. Deteriorated poles include poles that are damaged, burnt, decayed, or rotten and are at risk of failing and causing an ignition event.

FIGURE 2-7
DETERIORATED POLE

FIGURE 2-8
POLE SPLIT AT COMMUNICATION LEVEL

i) Routine Emergency Replacement

"Routine emergency" replacement refers to the replacement of equipment corresponding to the highest priority tags (the Priority A tags, as defined in *Scope and Prioritization* below) identified during the WSIP inspections. Routine emergency replacement work was conducted on equipment whose condition posed an imminent risk of failure.

ii) Idle Facilities Removal

Idle facilities removal refers to the removal of distribution facilities no longer in use to mitigate wildfire risks.

The replacement and removal activities described above were managed through the EC Tag process (described in *Scope & Prioritization* below) so that the work could be completed holistically based on tag priority and risk assessment, regardless of the type of work performed.

We verify inspection, maintenance, and construction work to ensure that it is completed in accordance with applicable standards and regulations. PG&E supervisors are responsible for implementing established procedures for work verification, including post-job checks and/or field monitoring of work by supervisors. In addition, Electric Operations has a dedicated Quality Control group that reviews a representative sample of completed inspection and maintenance work to determine whether it has been completed in accordance with the Commission's GOs and PG&E's construction standards.

3) Reason for Activity

The 2017 HFTD Fire Safety Decision made significant updates to GO 95 and GO 165 that impacted PG&E's distribution maintenance operations. The decision amended GO 95 to add reference to HFTD areas and to prioritize correction of safety hazards based, in part, on whether the hazard is in an HFTD area. The decision amended GO 165 to require annual patrols of overhead electric utility distribution facilities in HFTD areas. In addition, on August 31, 2018, the California Legislature passed SB (SB) 901, which required all publicly owned California utilities to construct, maintain, and operate their electrical lines and equipment in a manner that minimizes the risk of catastrophic wildfire posed by those electrical lines and equipment. As a result of SB 901, we established our WMP in 2019 (2019 WMP) to lay out PG&E's approach to mitigating wildfire risk caused by our electrical equipment.

In our 2019 WMP, we created the Wildfire Safety Inspection Program (WSIP) to enhance and prioritize inspections of electrical equipment located in HFTD areas. The distribution line system replacement work is an integral part of ensuring that pole and equipment weaknesses identified during WSIP inspections would be addressed. Preventing the failure of our HFTD overhead assets is essential for reducing the chances of wildfire ignition.

By prioritizing the replacement work in order of highest risk, we were able to address nearly all the highest risk corrective notifications (A and B tags) identified during the WSIP. In addition, by leveraging the System Hardening program through the EC

Optimization process, we were able to flag lower priority E and F tags to be addressed in future system hardening work.

4) Scope and Prioritization

EC tags are assigned a priority depending on the severity and urgency of the maintenance condition. Priority A tags are items identified in the field that require immediate correction. Tags that do not require immediate correction are submitted to PG&E's centralized review team. This team approves and prioritizes each corrective notification tag in the SAP Work Management system to initiate, assign, plan, execute, and close out repairs or replacements to facilities. The centralized review process is designed to result in consistent application of the priority classification of EC tags based on the risk posed by a given condition and the urgency of the necessary replacements. Table 2-7 below describes the priority tag classifications PG&E uses to comply with General Order (GO) 95, Rule 18.

TABLE 2-7
WSIP TAG PRIORITY CLASSIFICATION

Line No.	Tag Priority	Description
1	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").
2	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.
3	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).
4	F	The condition is of low potential impact to safety or reliability (corrective actions for distribution facilities is recommended to be addressed within 5 years from the date the condition is identified).
5	H	H priority tags refer to E and/or F tags that were re-assigned to a planned or existing System Hardening project.

Given the volume of identified EC tags in 2019, we used the following risk-informed approach to prioritize the highest risk issues on our facilities:

1) Address Priority A tags immediately;
2) Address Priority B tags prior to May but no later than 3-months after identification; and
3) Prioritize the execution of Priority E and F tags based on ignition risk circuit prioritization from the EC Optimization described below.

The largest volume of identified corrective actions from the 2019 WSIP were the Priority E and F tags. To address identified Priority E tags efficiently, while also mitigating the most risk system-wide, we conducted a holistic systematic review, or “EC Optimization,” of these identified “E” tags (and also reviewed “F” tags) on a circuit-by-circuit basis, prioritizing those distribution circuits that posed the highest risk of wildfire ignition. To leverage planned system hardening work, the EC Optimization process also resulted in the addition of an “H” priority tag. The H tag was created so that certain E and F tags identified from the WSIP inspections could be integrated with planned or existing system hardening projects, which helped to optimize completion of corrective tag work. These H priority tags were either assigned to a new or existing system hardening project or were part of a system hardening removal project.

5) Execution of Work

As a result of the enhanced and accelerated WSIP inspections in 2019, we identified a substantial amount of replacement work to be completed. The four types of WSIP replacement work were managed through the EC Optimization process so that the work could be completed holistically based on tag priority and risk assessment, regardless of type of work performed. Table 2-8 summarizes the WSIP replacement work we completed in 2019.

TABLE 2-8
SUMMARY OF WSIP DISTRIBUTION REPLACEMENT TAGS COMPLETED IN 2019

Line No.	Tags Completed by Priority A	B	E	F	H	Total
1	340	2,150	8,489	126	548	11,653

As described above, one of the outcomes of completing so many inspections in such a short period of time was a comparatively larger number of EC tags. Due to the accelerated nature of the WSIP Program and the high number of tags identified, we experienced an increase in the cost of the WSIP corrective action work as compared to routine replacement work. Primary drivers of this cost increase are described below.

- Expanded Workforce: In order to complete as many of the high priority A and B tags prior to fire season as possible, we had to significantly expand our workforce in a short period of time. To mitigate initial planning costs, we first looked to use internal labor from outside of Electric Operations, which included employees from Gas and Nuclear, to assist with the significant project management efforts required. After leveraging personnel internally to help with project management efforts, we began hiring in-state contractors (using the standard procurement process) to obtain the crews needed to perform the required maintenance in the given time frame. Due to the large number of contracting crews needed for the replacement work, the high demand of these in-state contracting crews from other California utilities ahead of the high-fire season, and the increased demand for contracting crews to assist with the larger inspection volume, we had to reach beyond the normal contractor pool and bring in crews from out of state to meet resource needs. As it was imperative that we complete this critical work ahead of the fire season, we prioritized selecting a contracting partner that was able to provide the necessary resources to complete the work in time. For these reasons, the external contractors who completed the majority of the 2019

WSIP replacement work were more expensive than external contractors in prior years.

- Overtime Premiums to Complete Work Before Fire Season: Due to the expedited nature of the WSIP and the limited availability of external contractor crews, we incurred significant contractor overtime costs in order to complete the high priority tag work before the high-fire season. We focused primarily on contracting on a 6/12 schedule to complete the work as efficiently as possible.

Below is a summary of the distribution replacement work completed in 2019 by type of work performed.

TABLE 2-9
SUMMARY OF WSIP REPLACEMENT TAGS COMPLETED IN 2019
BY TYPE OF WORK PERFORMED

Line No.	Type of Work	Tags Completed by Priority A	B	E	F	H	Total
1	Overhead Non-Pole Replacement	–	818	7,589	124	520	9,051
2	Deteriorated Pole Replacement	–	1,311	864	–	28	2,203
3	Routine Emergency Replacement	340	–	–	–	–	340
4	Idle Facilities Removal	–	21	36	2	–	59

b. Substation System Mitigations

TABLE 2-10
SUMMARY OF SUBSTATION SYSTEM MITIGATIONS 2019 COSTS
(THOUSANDS OF DOLLARS)

Line No.	Activity	MAT	Capital	Expense
1	Substation Defensible Space	IG#	–	$7,278
2	Substation Animal Abatement and Equipment Replacement	59F	$9,416	–
3	Total – Substation Mitigations		$9,416	$7,278

1) Background – WSIP Substation Inspections and Repairs (Excluded from Request)

As a part of routine preventative maintenance, we regularly inspect our substations to identify safety issues and potential areas of deterioration that could create unsafe situations or cause outages. Our enhanced Wildfire Safety Inspection Program (WSIP), introduced in the 2019 WMP, supplemented these routine substation inspections in HFTD areas to proactively identify and address deficiencies in substation equipment that could pose risk of ignition. We began performing enhanced substation inspections in 2019 as part of the WSIP, and thereby identified substations assets in HFTD areas needing repair or replacement.

Pursuant to the Wildfire OII Decision, we are not seeking recovery of costs associated with 2019 WSIP substation inspections or repair work in this application. We are only seeking recovery of costs associated with substation defensible space, substation animal abatement, and equipment replacement work identified as part of the WSIP in 2019.[25] These activities are discussed in the remainder of this subsection.

2) Nature of Activity

a) Substation Defensible Space

To mitigate wildfire risk, we assessed the area around substations in HFTD areas to ensure a safe distance, or defensible space, between trees and/or vegetation and critical infrastructure. Per CAL FIRE recommendations and state guidelines, we assessed the area within 100 feet of each substation and removed or thinned out trees and brush as necessary.

The 100-foot area around a substation is divided into two different zones. Zone 1 is referred to as the “Clean Zone,” and covers the 30-foot circumference around the substation (as measured from all outermost buildings or equipment). The Clean Zone creates a firebreak by removing all vegetation and combustibles within this 30-foot area. Combustible materials

[25] We also seek recovery of costs associated with distribution system replacement work performed in connection with WSIP inspections, discussed in *Section 1 – Distribution Line Replacement*s above.

may include logs, wood poles, woody debris, pallets, trash, and other combustible material.

The area that extends out from the 30-foot Clean Zone to 100 feet away from the outermost building or equipment is Zone 2, which is referred to as the "Reduced Fuel Zone." This area is designed to have a reduced fuel load to inhibit the progression and reduce the risk of a fire moving through the zone. Creating a Reduced Fuel Zone requires the following:

- Ensure that no combustible materials are left within the Reduced Fuel zone;
- Ensure that no loose surface litter exceeds a depth of 3 inches;
- Ensure that annual grass does not exceed a maximum height of 4 inches;
- Space trees 10 feet apart and prune branches at least 6 feet from the ground; and
- Space shrubs at a distance equal to twice the height of the shrub.

FIGURE 2-9
DEFENSIBLE SPACE ZONE

b) Substation Animal Abatement and Emergency Equipment Replacement

Substation replacement work performed in 2019 included animal abatement replacements and just-in-time equipment replacements. Animal contact is one of the leading causes of arc flash events which could lead to fire ignition. To mitigate this risk, we performed animal abatement upgrades by installing new or retrofitting existing animal abatement measures with the latest materials intended to reduce animal contacts. We performed these animal abatement upgrades as a result of the enhanced WSIP inspections to provide further mitigation against animal contacts.

Examples of substation animal abatement techniques include the following:

- Bait traps;
- Climbing guards (40-mil plastic sheet material with slick surface used on wood or steel poles to prevent squirrels from climbing poles to reach energized conductors); and
- Insulating Tape, Barriers, and Covers.

In addition, we performed equipment replacements for substation assets that were analyzed and determined to be deteriorated to a point where repairs were no longer economically feasible, referred to as just-in-time replacement. Addressing these assets was necessary to prevent imminent failure and potential ignition risk. Examples of just-in-time equipment replacements include circuit breakers, insulators, and switches.

3) Reason for Activity

As described above, SB 901 required all publicly-owned California utilities to submit WMPs to establish a plan for mitigating wildfire risk caused by their respective electric equipment. As part of our 2019 WMP, we defined the WSIP to enhance and prioritize inspections of substation equipment located in HFTD areas. The substation system defensible space, animal abatement and just-in-time replacement work were integral to ensuring that weaknesses identified during WSIP inspections were addressed in a timely and efficient manner.

a) Substation Defensible Space

We follow the guidelines set forth in California Public Resources Code Section 4291 (under the CA Department of Forestry and Fire Protection) for 100 feet defensible space in and around company-owned electric substations located in Tier 2 and Tier 3 areas.

b) Substation Animal Abatement and Emergency Equipment Replacement

Per PG&E's Standard TD-3350P-10, the substation animal abatement program was designed to improve reliability by mitigating outages due to animal contacts within substations. Additional requirements were implemented following the enhanced WSIP inspections to provide more mitigation against animal contacts. For substations located in HFTD areas, when defensible space could not be achieved due to geographical constraints, an expanded standard called for 24-inches of additional cover for feeder disconnect switches and buswork conductor, which runs from the feeder disconnect switches towards the main bus(es).

In addition, the just-in-time equipment replacement work was critical for ensuring that substation assets deemed beyond repair were replaced in a timely manner to reduce wildfire ignition risk.

4) Scope and Prioritization

In 2019, we performed defensible space clearance work for 186 out of 195 PG&E-owned distribution substations located in the HFTD areas. Defensible space work for the remaining nine substations is in progress and planned to be completed by the end of 2020.

In 2019, 55 substations were identified as needing animal abatement replacements, and these upgrades were completed at 19 sites. Animal abatement for the remaining 36 substations are in progress and are planned to be completed by the end of 2020.

In 2019, 16 substation assets were identified as needing just-in-time replacements, and four were completed. The remaining 12 substation asset replacements are currently in progress and are planned to be completed by the end of 2020.

5) Execution of Work

a) Substation Defensible Space

In 2019, we spent a total of $7.3 million to conduct defensible space clearing of vegetation and other combustible material around distribution substations within HFTD areas. In 2019, we cleared vegetation and other combustible materials surrounding 186 distribution substations.

TABLE 2-11
SUMMARY OF SUBSTATION DISTRIBUTION DEFENSIBLE SPACE 2019 PERFORMANCE

Line No.	Wildfire Mitigation Activity	2019 Performance	Units
1	Substation Defensible Space Clearing Completed	186	Substations
2	In Progress	9	Substations

b) Substation Animal Abatement and Emergency Equipment Replacement

Of the $9.4 million Capital expenditure, $7.3 million was spent on animal abatements and $2.1 million was spent for the just-in-time replacements. In 2019, animal abatement upgrades were completed at 19 sites.

TABLE 2-12
SUMMARY OF SUBSTATION ANIMAL ABATEMENTS 2019 PERFORMANCE

Line No.	Wildfire Mitigation Activity	2019 Performance	Units
1	Substation Animal Abatement Replacements	19	Substations

In 2019, four substation assets requiring just-in-time replacement were replaced.

TABLE 2-13
SUMMARY OF SUBSTATION JUST-IN-TIME REPLACEMENTS 2019 PERFORMANCE

Line No.	Wildfire Mitigation Activity	2019 Performance	Units
1	Substation Just-In-Time Replacements	4	Substation Assets

2. System Hardening and Other Grid Modifications

System hardening involves replacing distribution lines with equipment that is less likely to start a fire and more likely to survive one or, if possible, eliminating certain distribution lines in HFTD areas. In addition, system automation is another important tool we use to prevent and mitigate fires associated with utility equipment. In 2019, we began work to harden and automate our distribution system in response to the increased wildfire risk.

This section discusses three activities: (1) System Hardening Program, (2) Granular Sectionalizing (PSPS) & Automation and Protection (SCADA), and (3) Non-Exempt Equipment and Resilience Zones, as shown in Table 2-14 below.

TABLE 2-14
SUMMARY OF SYSTEM HARDENING AND OTHER GRID MODIFICATIONS 2019 COSTS
(THOUSANDS OF DOLLARS)

Line No.	Activity	MAT	Capital	Expense
1	System Hardening Program	08W, 23C, 23#	$270,059	–
2	Granular Sectionalizing (PSPS) and Automation and Protection (SCADA)	49H, 09A	56,145	–
3	Non-Exempt Equipment and Resilience Zones	2AP, 49M	11,785	–
4	Total – System Hardening and Other Grid Modifications	–	$337,989	–

Each of these activities is discussed in detail below.

a. System Hardening Program

TABLE 2-15
SUMMARY OF SYSTEM HARDENING PROGRAM 2019 COSTS
(THOUSANDS OF DOLLARS)

Line No.	Activity	MAT Code	Capital	Expense
1	Completed Projects	08W	$217,824	–
2	In Progress Projects	08W, 23C, 23#	36,134	–
3	In Progress Projects – Butte Rebuild	08W	16,100	–
4	Total – System Hardening Program		$270,059	–

1) Nature of Activity

PG&E's System Hardening Program is an ongoing, long-term capital investment program to rebuild portions of our overhead electric distribution system to reduce the risk of potential ignitions associated with our facilities and equipment. This involves the elimination, rerouting, and rebuilding of sections of specific distribution circuits with the highest fire risk in HFTD areas.

Hardening methods include:

- Replacing existing wood poles with newer more resilient poles to improve fire resistance and support the additional weight of covered conductor, which replaced primary and secondary conductor to prevent ignitions caused by contact with falling trees or tree limbs, or by bare wires contacting each other in high winds;
- Conversion of overhead distribution lines to underground cable where feasible and prudent; and
- Removal of overhead lines.

Additional details about the types of hardening methods we used in 2019 are provided below.

a) Overhead System Hardening

There are two components for hardening overhead lines: pole replacement and covered conductor.

i) Pole Replacement

In 2019, the PG&E distribution standard for overhead construction was open conductor and wood poles. This system was designed and constructed in accordance with GO 95, and the overhead system was engineered and built with electrical, structural, and mechanical considerations in mind. The poles are designed by PG&E experts utilizing an industry standard tool to calculate structural integrity (vertical and transverse loading). The conductors are sized appropriately for the electrical loading as well as mechanical integrity in sag and tension. All variables used in our engineering analysis are consistent with or exceed those set by the CPUC.

Under the System Hardening program, our enhanced pole loading model parameters and variables to address various environmental factors (e.g., wind speed). Sizing for new and replacement distribution pole installations considered historical peak wind speeds in areas where they exceeded the GO 95-assumed wind speeds. In order to maximize the likelihood that poles were strong enough to withstand higher wind speeds, a pole loading calculation was performed both at the loading conditions assumed by GO 95 conditions (load case) and at a summer peak wind load case. Due to the replacement of bare wire with heavier covered conductor, as well as the increased stringency of pole loading requirements, we needed to replace most existing poles in locations where System Hardening occurred. In 2019, we installed approximately 3,700 new wood poles as part of system hardening projects.

ii) Covered Conductor

The replacement of bare conductors with larger covered conductors further reduces the likelihood of faults due to trees, branches, animals, or birds contacting lines, and further reduces situations where bare wires slap together in high winds, which can generate sparks or molten metal. The HFTD areas within our territory have a high volume of vegetation with large overhangs and ground fuels where the covered conductor is an effective risk mitigation. Thus, installation of covered conductors can be effective in providing fire reduction and reliability improvements from contact outages in heavily treed areas. We replaced bare overhead distribution primary (high voltage) and secondary 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.

The primary covered conductor coating we used was abrasion resistant crosslinked thermoset polyethylene. Crosslinked thermoset polyethylene covering is a new standard, which is an improvement over PG&E's prior standard, non-crosslinked thermoplastic polyethylene covering, because of its:

- Superior temperature resistance due to its higher softening point and cable used for a higher covering rating of 90°C versus 75°C;
- Increased chemical resistance at ambient and elevated temperatures; and
- Higher tensile strength, rigidity and hardness.

FIGURE 2-10
COVERED CONDUCTOR (TREE WIRE)

b) Undergrounding

As we conducted reviews of portions of circuits planned for system hardening, we identified circuits, or portions of circuits, in HFTD areas where it may be prudent and feasible to underground the overhead distribution lines. These circuits were typically in locations along main egress routes that needed to remain clear for first responders and evacuations, where a rebuilt overhead circuit could still have posed a threat of burned or downed poles blocking access in the event of a wildfire. Other circuits where undergrounding was prudent involved areas with dense vegetation that posed an elevated risk of a tree falling onto an overhead line. We have determined that, in these instances, undergrounding of portions of circuits is reasonable and prudent and increases the safety of our customers and the communities we serve.

We evaluated opportunities to underground overhead circuits wherever it was operationally feasible, taking into account that undergrounding is more expensive, takes longer, and requires additional land rights and permits compared to the hardening of overhead circuits. As with all system hardening work, we began the identification of potential circuits to be undergrounded by utilizing the risk informed prioritization approach (see *Scope and Prioritization* below for more details) to identify those circuits with the highest wildfire risk. Based on the risk ranking, we conducted estimates of the feasibility for undergrounding a particular circuit based on a number of criteria, including: (1) if the circuit contained long stretches of lines without large amounts of overhead equipment installed; (2) if the circuit, based on its location, had potential land rights issues; and (3) if the circuit was located in an area that would make it practical and expedient to obtain the appropriate permits.

Only a relatively small proportion of the circuit miles included in the System Hardening Program was undergrounded in 2019. Of the 171 miles of total System Hardening work completed in 2019, approximately 7 miles was undergrounding work. The balance between overhead hardening and underground was determined as the projects were scoped. We used the same procedures and equipment to underground facilities as part of the System Hardening Program as we did for other undergrounding projects.

c) Removal of Overhead Lines

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. In 2019, we completed approximately 33 miles of line removal as part of the System Hardening Program, of which approximately 12 miles is included in Major Work Category (MWC) 08.

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. Based on our experience of recent wildfires in our service area, study of other utilities, and our analysis of CPUC reportable ignitions on its system, we 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 the primary system hardening methods described in this section, our System Hardening Program includes other system hardening activities such as: bird/animal guards that are installed where necessary to help prevent electrical contacts and outages, and the replacement of existing primary line equipment, such as fuses and cutouts, with equipment that has been certified by CAL FIRE as lower fire risk and therefore exempt from vegetation clearance requirements (see *Section e. – Non-Exempt Equipment*).

2) Reason for Activity

As described above, SB 901 required all publicly-owned California utilities to submit WMPs to establish a plan for mitigating wildfire risk caused by their respective electric equipment. As part of our 2019 WMP, we introduced the System Hardening Program. Our investment in the System Hardening Program has resulted in an enhancement of the overhead distribution system through the replacement and upgrade of aging or high-risk assets with the use of more advanced materials and technologies. Through continued system hardening activities, we increase the overall strength of the distribution system and reduce risk from external factors, such as vegetation contacting lines, ignition events caused by flammable materials, and equipment failure in aging overhead assets.

3) Scope and Prioritization

In 2019, we completed hardening of 125.3 circuit miles for which we seek recovery in this filing. The System Hardening Program is a multi-year program, and we plan to upgrade approximately 7,100 circuit miles in Tier 2 and Tier 3 HFTD areas over the next 12 to 14 years.

We leveraged a risk informed approach[26] to scope the system hardening work, which is composed of several key factors, including the following:

- Likelihood of ignition, which was determined based on a regression analysis predicting ignitions at the circuit level;

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[26] For more information on the risk informed approach for scoping system hardening work reference PG&E's 2019 WMP (R.18-10-007).

- Likelihood of spread, which was determined based on a study conducted by PG&E and a third party;
- Consequence considerations, which focused on the potential impact of a wildfire; and
- Egress analysis, which assessed the difficulty to access or evacuate communities.

The precise scope of hardening work was site-specific and dependent on local conditions, and the risk informed approach factored in additional operational constraints that would impact the ability to perform the work, such as land/environment considerations, safety considerations, geographic access considerations, etc. Not every measure was effective or necessary at every location. As we implemented the System Hardening program, evaluations of the design took place, including considerations of local conditions to optimize the appropriate solution for that location. For example, as described above, we performed undergrounding of select overhead lines where appropriate.

Another factor that influenced the prioritization of System Hardening projects was an analysis of the resulting Electric Corrective (EC) tags identified in the course of the WSIP (see EC Optimization description in *Section a. –" Distribution Line System Replacements"*). We determined that there are locations where a high density of EC tags coincide with areas that also scored highly in the System Hardening risk ranking. To drive efficiency, reduce cost, and reduce resource demands, we created System Hardening projects in these areas, even if they are not the highest scoring areas in the risk ranking. As described in the "Distribution Line System Replacements" – "Reason for Activity" subsection, after an internal review/analysis, these EC tags were assigned a priority "H" tag status to designate that they would be addressed as part of an existing or planned System Hardening project.

4) Execution of Work

For each of the three system hardening methods (overhead, underground, or removal) described above, we collectively managed the status and executed the work of each project according to the following categories:

- Completed Projects: Projects that were completed or partially completed in 2019 and passed all quality assurance criteria.
- In Progress Projects: Projects that were initiated and/or worked on in 2019 but were not completed in 2019

For System Hardening projects specifically, a new class of quality checks were created in 2019 to inspect for "fire safety risks" along with adherence to hardening standards, not just general work procedures or administrative errors. We used our internal QC team to conduct reviews of System Hardening work in order to deem it complete. In the QC process, initial reviews were performed during construction and full assessments were done post-construction. In addition, the QC team was present during wire pulls to ensure all potential fire risks were addressed immediately. Reviews included specific pass/fail entries for each span/location of a given project.

In 2019, we completed 125.3 circuit miles for which we seek recovery in this filing.

For MWC 08W, we are seeking recovery for:

- Completed Projects for MWC 08W – 125.3 miles of System Hardening work, of which 12.1 miles is removal of idle facilities not included in MWC 08W costs; and
- In Progress Projects for MWC 08W.

The incremental costs associated with the System Hardening Program activities described in this section are recorded to the WMPMA and are summarized below.

a) Completed Projects

In 2019, we completed 125.3 miles across 99 projects at a total cost of $217.8M. The 2019 completed work was comprised of:

- 108 miles of overhead equipment replacement, resulting in 2,805 poles retired and 3,766 new poles that were installed;
- 3.4 miles of undergrounding work; and
- 1.8 miles of line removal.

The completed project work resulted in a 2019 unit cost of $1.7 million per completed mile. Several factors contributed to the unit cost, including:

- Higher equipment costs for the overhead hardening methods, such as fire-resistant poles and covered conductors;
- Increased contractor costs;
- In order to complete hardening work in densely forested areas that were difficult to access, approximately $36 million of costs related to providing construction access and safety clearance were incurred in order to safely perform construction; and
- $12.8 million spent to complete the 3.4 miles of underground work. Undergrounding work is typically more expensive as it involves more digging and trenching for the cable.

b) In Progress Projects

In 2019, we also performed $36.1 million of work for projects that were not completed during the calendar year. These projects vary between projects that were newly initiated and in the engineering phase to projects that had completed portions of their scope of work for system hardening but had not yet reached the point of completion and been verified through the quality assurance process. It is anticipated that these in progress projects will progress to completed projects in future years.

Given the long timespan of the System Hardening program, the timing of projects may be adjusted based on events on the ground, such as storms or wildfires. These shifts reflect a change in timing of when the work is completed, and not a change in the scope of the System Hardening program. For example, included in the in progress projects is $16.1 million of system hardening work to harden portions of the electric distribution system that were destroyed as part of the 2018 Camp Fire in Butte County. Butte County was included in the original scope for the System Hardening program and the timing was accelerated to best serve the needs of the customers in the area.

b. Granular Sectionalizing (PSPS) and Automation and Protection (SCADA)

TABLE 2-16
SUMMARY OF GRANULAR SECTIONALIZING (PSPS) & AUTOMATION AND PROTECTION (SCADA) 2019 COSTS
(THOUSANDS OF DOLLARS)

Line No.	Activity	MAT	Capital	Expense
1	Granular Sectionalizing (PSPS)	49H	$49,489	–
2	Automation and Protection (SCADA)	09A	6,656	–
3	Total – Sectionalization and Automation		$56,145	–

1) Nature of Activity

In 2018, the CPUC issued Resolution ESRB-8 which confirmed the need for all California utilities to use PSPS (Public Safety Power Shutoff) as a means 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 our distribution assets are located. Under extremely high-risk conditions, it is necessary to deenergize some distribution lines to reduce the risk of vegetation or other flammable items contacting live wires and starting wildfires.

In 2019, we conducted nine PSPS events, mostly during October and November, that caused outages affecting hundreds of thousands of customers. While the PSPS events were successful in that utility equipment caused fewer overall ignitions within HFTD areas and no fatal wildfires occurred in 2019, those events caused severe disruptions for the communities and customers we serve. The following costs relate to our efforts to minimize the impact of PSPS events.[27]

a) Granular Sectionalizing (PSPS)

Granular Sectionalizing entails upgrading specific devices 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, and to allow for increased targeting of the PSPS program. Sectionalization devices 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.

b) Automation and Protection (SCADA)

In addition to Granular Sectionalizing, we created system Automation and Protection in HFTD areas by deploying SCADA-enabled reclosers (shown in the figure below) which allow PG&E to remotely disable reclosing devices during elevated wildfire conditions. Under normal conditions, reclosing devices are used to maintain customer power. However, during extreme fire conditions this practice could increase fire risk. Therefore, being able to disable reclosing devices during fire conditions is an important mitigation factor to reducing wildfire risk.

PG&E internal standards establish precautions for wildfire risks associated with recloser protection functions. Reclosing devices such as circuit breakers and reclosers are used to quickly and safely de-energize lines when a problem is detected and automatically re-energize lines when the problem is cleared. Reclosing devices that are not SCADA-enabled must

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27 Refer to the section titled “Public Safety Power Shutoffs” for costs related to our 2019 PSPS events.

be turned on or off manually, which requires sending personnel out to the field. While manual switches help us minimize PSPS events by isolating customers, the need to send personnel out to control them make them more difficult to operate in the midst of a PSPS event. By automating all switches with SCADA capability, we can more effectively prevent PSPS outages for customers and avert the danger of manually operating reclosers during a high fire threat season or event.

FIGURE 2-11
SCADA RECLOSER INSTALLED ON POLE

Using analyses provided by CAL FIRE officials and PG&E's Meteorology team regarding each year's fire season timeline and exposure, we make an informed decision on when to disable automated reclosing during elevated fire conditions in HFTD areas. 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, all automated reclosing devices for distribution lines are disabled during the determined utility fire risk season for protection zones that intersect HFTD areas. This practice reduces potential ignitions from sustained faults.

2) Reason for Activity

In its 2018 Resolution ESRB-8, the CPUC confirmed the need for all California utilities to use PSPS (Public Safety Power Shutoffs) as a means to prevent catastrophic wildfires. Following the 2019 wildfire season and the active use of PSPS due to numerous dangerous weather events, the Governor requested that California utilities add PSPS impact mitigation to its prioritization exercises. The CPUC incorporated the Governor's request into the 2020 WMP requirements.

Our investment in Granular Sectionalizing is customer-focused and enables us to more precisely control and limit the size and sections of circuits that have to be taken out of service in a PSPS event. By making those PSPS areas smaller, we reduce the number of customers affected by an outage event and decrease the restoration time for customers that are within the de-energization area by minimizing the amount of overhead facilities that need to be patrolled for safety.

Our investment in SCADA Automation and Protection enables us to handle faults in a contained manner by allowing system operators in our control room to remotely prevent lines from automatically re-energizing ("reclosing") after a fault. This ensures 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 our personnel can verify that it is safe to put the line back in operation.

Together, the Granular Sectionalizing and SCADA Automation and Protection activities described in this section mitigate the risk of wildfires and lessen customer impact by upgrading our distribution equipment to prevent potential faults or failures and automating vital processes to enable a more proactive response and faster restoration.

3) Scope and Prioritization

a) Granular Sectionalizing (PSPS)

In analyzing a distribution circuit for possible PSPS sectionalization, we identify those overhead line segments which extend into the HFTD areas and are within the de-energization scope. By isolating the lines closer to the border of the HFTD area, fewer customers are impacted and fewer lines need to be de-energized. Each line segment is then traced upstream towards the substation until a sectionalizing device located outside of potential de-energization scope or HFTD area is identified. This process is completed for all branches of the entire circuit. When a sectionalizing device is identified, the circuit can be sectionalized with segments downstream (i.e., away from the substation) of the device being deenergized while allowing segments upstream of the device to remain energized.

b) Automation and Protection (SCADA)

With respect to automated recloser operations, in 2019 we SCADA-enabled 289 line reclosers in Tier 2 and Tier 3 HFTD areas.

4) Execution of Work

a) Granular Sectionalizing (PSPS)

In 2019, we performed work on 298 sectionalization devices and were able to commission 232 devices. Once a sectionalization device is installed, the device is “commissioned” once the distribution system operators, line technicians, and data specialists perform testing and get the device communications operational so the device can be operated remotely. We prioritized completing work for Mainline devices ahead of Tapline devices and were able to commission 180 Mainline and 52 Tapline devices. The remaining 66 devices not commissioned in 2019 are anticipated to be commissioned in future years.

We used four different types of sectionalizing devices for the manual switch upgrades: reclosers, CAL FIRE exempt "Motorized Switch Operator" (MSO) switches, fuse-savers, and underground SCADA switches. Of the 298 devices where work was performed in 2019, the work consisted of 160 reclosers, 134 CAL FIRE exempt MSO switches, 3 fuse-savers, and 1 underground SCADA switch.

TABLE 2-17
SUMMARY OF 2019 GRANULAR SECTIONALIZING DEVICES (PSPS)

Line No.	Wildfire Mitigation Activity	Category	Devices Installed	Devices Commissioned
1	Distribution Sectionalization	Mainline	187	180
2		Tapline	111	52
3		Total	298	232

Our 2019 average unit cost for installing the sectionalization devices was approximately $125,000. Primary drivers of this unit cost included: (1) adding bypass switches to the devices; (2) pre-purchasing MSO switches; and (3) performing the work using external contracting crews. Each of these items is discussed below.

a) Adding bypass switches to the sectionalization devices allowed PG&E to avoid customer outages by taking the new equipment out of service when conducting maintenance.

b) In order to expedite the completion of the work, in 2019 we pre-purchased all of the CAL FIRE exempt MSO switches in preparation for current and future work.

c) All of the sectionalization devices were installed by external contracting crews. As PG&E prioritized the Mainline devices, contractors completing this work were brought on first using a competitive bid agreement. For the Tapline work, due to the lack of available crews, PG&E hired contractors at a more expensive "daily crew rate."

Our total spend for installing and commissioning sectionalization devices in 2019 was $52.7 million.

b) Automation and Protection (SCADA)

In 2019, we completed SCADA-enabling 289 reclosers serving HFTD areas.

TABLE 2-18
SUMMARY OF 2019 AUTOMATION AND PROTECTION (SCADA)

Line No.	Wildfire Mitigation Activity	2019 Performance
1	Automation and Protection (SCADA)	289 Line Reclosers

Our total spend for automating line reclosers with SCADA in 2019 was $6.7 million.

c. Non-Exempt Equipment and Resilience Zones

TABLE 2-19
SUMMARY OF NON-EXEMPT EQUIPMENT AND RESILIENCE ZONES 2019 COSTS (THOUSANDS OF DOLLARS)

Line No.	Activity	MAT	Capital	Expense
1	Replacement of Non Exempt Fuses	2AP	$8,517	–
2	Resilience Zones/Microgrids	49M	3,268	–
3	Total – Non Exempt Equipment and Resilience Zones		$11,785	–

1) Nature of Activity

In addition to the PSPS sectionalization and Automation efforts described in Section 2.C.5, our wildfire mitigation efforts included other Grid Modification efforts: the replacement of Non-Exempt Equipment and the development of Resilience Zones.

a) Replacement of Non-Exempt Fuses

Replacement of Non-Exempt Equipment refers to the replacement of existing primary line equipment such as fuses and cutouts with equipment that has been certified by CAL FIRE as low fire risk and therefore exempt from vegetation clearance. This replacement work eliminates overhead line equipment and devices that may generate exposed electrical arcs, sparks, or hot material during their operation.

b) Resilience Zones/Microgrids

PG&E uses the term "Resilience Zones" to describe projects that allow us to safely provide electricity to central community resources when PSPS is activated. Customers near Resilience Zones benefit from the ability to access services, such as grocery stores and gas stations while the wider grid is de-energized for safety. Host sites for Resilience Zones are selected in full coordination with the System Hardening Program for safe operation. This coordination between the programs includes aligning around common criteria that define an area as safe to energize during PSPS events. We select sites that feature primarily underground infrastructure or are in the System Hardening scope for undergrounding. In the instances that a site requires additional undergrounding or vegetation management to function as a Resilience Zone, the work is coordinated with our Asset Strategy group to ensure it does not conflict with future System Hardening plans.

Resilience Zones are enabled by pre-configured segments of the distribution system that can be quickly isolated from the broader grid when a PSPS is initiated. Using pre-installed interconnection hubs (PIH), we are able quickly and safely to connect temporary mobile generation to energize the isolated Resilience Zone. Generally, PIHs consist of a transformer and associated interconnection equipment, ground grid, and grid isolation and protection devices such as reclosers and switches.

Resilience Zone PIHs evolve into Resilience Zone "Microgrids" over time, as preferred resource combinations begin to meet technical requirements, and as our capability to operate these systems matures. The ability to disconnect completely from the centralized grid at key times can allow for sustained backup generation to critical facilities in communities working to respond and recover from wildfires and other natural disasters.

2) Reason for Activity

a) Replacement of Non-Exempt Fuses

With increasing wildfire risks caused by changing climate conditions, as described in our 2019 WMP, this program was created to replace non-exempt fuses and cutouts in HFTD areas to further reduce fire risk. The replacement of non-exempt equipment with exempt equipment further reduces fire risk since this equipment is non-expulsion and does not generate arcs/sparks during normal operation. Due to these characteristics, CAL FIRE Public Resource Code (PRC) Section 4292[28] 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 safe to use.

b) Resilience Zones/Microgrids

Our investment in Resilience Zones helps achieve 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.

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28 PRC 4292 is administered by CAL FIRE, and requires that PG&E maintain a firebreak of at least 10 feet in radius of a utility pole, with tree limbs within the 10-foot radius of thee pole being removed up to eight feet above ground. From eight feet to conductor height requires removal of dead, diseased or dying limbs and foliage. This applies in the State Responsibility Area during designated fire season.

3) Scope and Prioritization

a) Replacement of Non-Exempt Fuses

We estimate that PG&E has 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 poses a potential fire risk, and we plan to replace these units in future years.

b) Resilience Zones/Microgrids

In our 2019 WMP, we described our 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. Angwin is a town situated within the Tier 3 HFTD area in Napa County (Fire Index Area 175). We worked with Pacific Union College to align the operation of the Resilience Zone with the college's privately-owned cogeneration plant to collaboratively increase resilience for the town of Angwin. The presence of the Resilience Zone allows us safely to energize facilities such as the fire station, gas station, Brookside Apartments, and portions of the Angwin Plaza not already served by the local college's on-campus generation.

4) Execution of Work

a) Replacement of Non-Exempt Fuses

In 2019 we replaced 708 fuses/cutouts located in Tier 2 or Tier 3 HFTD areas.

TABLE 2-20
SUMMARY OF NON-EXEMPT FUSE REPLACEMENT WORK PERFORMED IN 2019

Line No.	Wildfire Mitigation Activity	2019 Performance
1	Replacing Non-Exempt Fuses	708 Fuses/Cutouts

b) Resilience Zones/Microgrids

In 2019 we successfully used temporary generation at our pilot mid-feeder microgrid site. We temporarily stood up and operated three additional microgrids in Calistoga, Placerville, and Grass Valley during the October and November 2019 PSPS events, though costs associated with those activities were not charged to MAT 49M and we do not seek to recover them in this chapter.

TABLE 2-21
SUMMARY OF 2019 RESILIENCE ZONE/MICROGRID WORK PERFORMED

Line No.	Wildfire Mitigation Activity	2019 Actual Units
1	Temporary Microgrids (MAT Code 49M)	One Completed Pilot Resilience Zone + Work on Future Sites

The map in Figure 2-12 below represents the approximate area served by PG&E's temporary microgrid in Angwin.

FIGURE 2-12
ANGWIN TEMPORARY MICROGRID MAP

Of the $3.3 million spent in 2019, $733,000 was incurred to cover capital costs for the pilot Resilience Zone completed in Angwin, including site design, major equipment, and construction. The remaining $2.57 million covered overall program management costs ($1.5 million), as well as capital costs for additional microgrids that began development in 2019 but will not be operational until a future date. This includes land, major equipment (e.g., transformers, reclosers, camlock boxes), and engineering costs for sites including but not limited to Calistoga ($224,000), Georgetown ($340,000), Shingletown ($165,000), and Pollock Pines ($140,000), which we are working to complete in 2020.

3. Incremental Vegetation Management

a. Introduction

This section describes PG&E's incremental Vegetation Management activities to reduce the risk of wildfires. The incremental activities described herein augment our routine and drought response Vegetation Management work and make our system safer by:

- Reducing the likelihood of a wildfire ignition due to vegetation and powerline interaction;
- Mitigating the intensity and spread of a wildfire, were one to start;
- Assisting first responders in their response to fires adjacent to or under powerlines;
- Reducing wire down events; and
- Improving electric reliability through the reduction of vegetation-caused power outages.

In response to Southern California wildfires in 2007, the CPUC initiated R.08-11-005 to adopt regulations to protect the public from potential fire hazards associated with overhead power lines. Beginning in 2009, the CPUC issued several decisions in R.08-11-005 that created new fire-safety regulations, including the requirement that PG&E annually create a Fire Prevention Plan. Several of the fire-safety regulations adopted in R.08-11-005 create new safety standards for "high fire-threat areas;" which, among other things, increased vegetation clearances required year-round from high voltage lines in the HFTD areas. In a parallel track to the rulemaking process, the CPUC worked with Communication Infrastructure Providers, California's electric utilities, and CAL FIRE to develop the maps that established the HFTD areas.

The incremental fire risk reduction activities and associated costs we describe below are driven largely by the expansion of the areas within PG&E's territory that became designated as high fire threat areas, the stricter fire-safety regulations that apply to them, and the requirement to develop a Fire Prevention Plan to further reduce fire risk. Previous fire threat maps designated only a small portion of PG&E's service area in Santa Barbara County as high fire threat area. By 2018, the HFTD Map encompassed about 32 percent of PG&E's overhead distribution line miles. Furthermore, approximately 65 percent of California IOUs' overhead distribution circuits located in HFTD areas are within PG&E's service area.[29]

Figures 2-13 and 2-14 illustrate the expansion of designated high fire threat areas.

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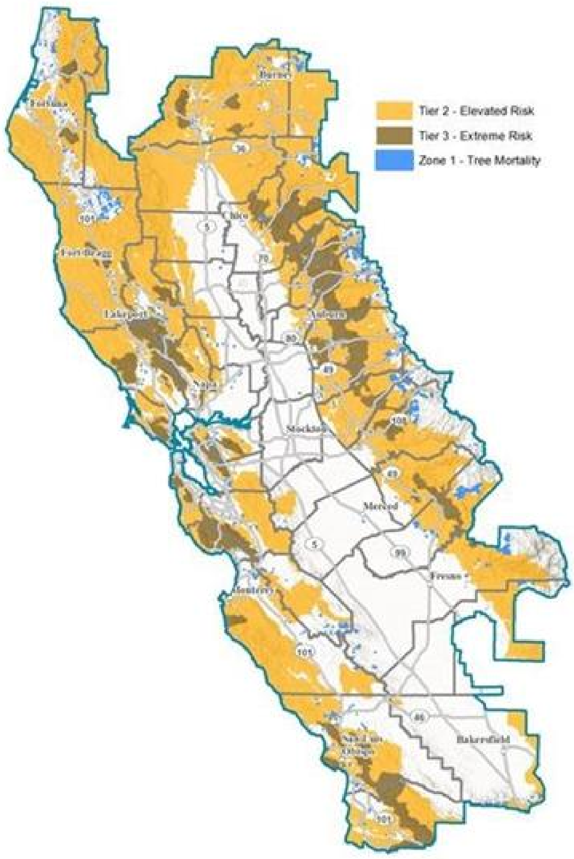
29 See D.12-01-032 (January 18, 2012), at 262–63, available at: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/157605.PDF (showing Reax Map for Northern California and FRAP Map for Santa Barbara County).

FIGURE 2-13
OLD HFTD AREAS

FIGURE 2-14
NEW HFTD AREAS



Associated incremental costs for the Vegetation Management activities discussed below are accounted for in the FHPMA and the FRMMA/WMPMA.

This testimony organizes the Vegetation Management programs and activities within those accounts as follows: (1) PG&E's Fire Prevention Plan, (2) increased inspections and associated tree work in HFTD areas, (3) Fuel Reduction, (4) Accelerated Wildfire Risk Reduction (AWRR), and (5) Enhanced Vegetation Management.

Recorded costs for 2012 through 2019 for these incremental Vegetation Management activities are shown in the Table 2-22 below. Pursuant to the settlement of the Wildfire OII, I.19-06-015 (Wildfire OII Decision), we are not seeking recovery of some costs associated with Vegetation Management programs in this application. The costs that we have omitted from this request in accordance with the Wildfire OII Decision are reflected in Table 2-22.

TABLE 2-22
INCREMENTAL VEGETATION MANAGEMENT REQUEST
(THOUSANDS OF DOLLARS)

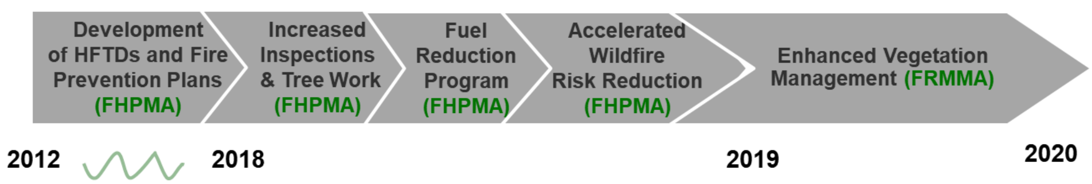
Line No.	Activity	Account	MAT Code	2012-2016 Expense	2017 Expense	2018 Expense	2019 Expense	2019 FHPMA Wildfire OII Decision	Total WMCE Request
1	Fire Prevention Plan	FHPMA	IG#	$388	$404	$(167)[a]	–	–	$625
2	Increased Inspections and Tree Work in HFTD areas	FHPMA	IG#	–	–	1,763	2	–	1,765
3	Fuel Reduction	FHPMA	IG#	–	–	35,634	1,975	–	37,609
4	Accelerated Wildfire Risk Reduction	FHPMA	IG#	–	–	269,015	20,708	(34,686)	255,037
5	Enhanced Vegetation Management	WMPMA	IG#	–	–	–	449,502	–	449,502
6	Totals			$388	$404	$306,245	$472,187	$(34,686)	$744,538

(a) An accounting credit was applied in 2018.

The testimony below is generally organized in chronological order and describes the development of PG&E's initial Fire Prevention Plan and the evolution and expansion of PG&E's Vegetation Management programmatic activities. From 2012 through 2017, we worked with the Commission and stakeholders to develop the fire maps and Fire Prevention Plans.[30] Subsequent to the adoption of the CPUC's HFTD Map in January 2018, we established and began implementation of our Fuel Reduction Program. In September 2018, we expanded the scope, scale, and pace of the program and implemented a short-term Accelerated Wildfire Risk Reduction approach. Finally, in December 2018, we refined this wildfire risk reduction approach to Vegetation Management and created the current, and more sustainable, Enhanced Vegetation Management Program.

The timeline for these incremental vegetation management activities is illustrated in Figure 2-15.

FIGURE 2-15
TIMELINE OF VEGETATION MANAGEMENT ACTIVITIES



b. Fire Prevention Plan

From 2012-2018, PG&E, Communication Infrastructure Providers, CAL FIRE, and the other California IOUs worked with the Commission to develop the fire maps and develop Fire Prevention Plans. Recorded costs for 2012 through 2018 reflecting our contribution to the development of the CPUC's HFTD Map and associated activities is shown in Table 2-23 below.

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30 The term "Fire Prevention Plans" are used to describe the earlier versions of PG&E's current version for the Wildfire Mitigation Plan filed with the Commission on an annual basis. Decision 12-01-032 (January 12, 2012) updated CPUC General Order 166, which required the development of fire prevention plans by investor owned utilities.

TABLE 2-23
FIRE PREVENTION PLAN EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Activity	MAT	2012-2016 Expense	2017 Expense	2018 Expense
1	Geographic Information Systems (GIS)	IG#	$252	$400	$(168)[(a)]
2	Climatology	IG#	68	4	–
3	REAX Engineering	IG#	68	–	–
4	Total - Fire Prevention Plan		$388	$404	$(168)

(a) An accounting credit was applied in 2018.

1) Nature of Activity

We worked with the CPUC, Communication Infrastructure Providers, other California electric utilities and CAL FIRE to develop the maps that ultimately established the HFTD areas. SCE, SDG&E, and PG&E provided proportional funding for contractor support throughout the development process that resulted in Fire Map 1, adopted by the CPUC in May 2015. This map was one of the first in the state to incorporate robust climatological analysis to define the conditions that fire spread modeling could use.

Building off Fire Map 1, we contributed to a Map 2 development workplan through a series of workshops from 2015 through 2016 at the CPUC with other stakeholders. The CPUC workplan defined the process to develop Fire Map 2, a three tiered, statewide map to identify areas where enhanced fire-safety regulations would apply. The Administrative Law Judge assigned PG&E to Co-Lead the mapping effort with SDG&E and REAX Engineering. Our employees worked with stakeholders in the incremental and iterative process to refine areas of increased risk of wildfires caused by utility equipment.

Our contribution to this multi-party[31] effort and the associated incremental costs are discussed below.

31 The primary responsibility for the development of the CPUC Fire-Threat Map lay with a small group of utility personnel and consultants, known as the Peer Development Panel.

a) **Climatology**

Between 2012 and 2017,[32] our meteorology staff supported development of the PG&E Operational Mesoscale Modeling System (POMMS). This modeling system provided more granular and accurate weather forecasting input to our storm damage and fire danger prediction model, and to other of our forecasting applications. Our meteorology team developed the system to support our Fire Potential Index using high-resolution weather and fuels climatology.[33]

Our meteorology staff participated in Fire OIR workshops and supported the development of proceeding documents, which included the continued development of Fire Prevention Plan situational awareness content. We also coordinated the wind exceedance studies mandated by revision to GO 166 and evaluated fire spread modeling.

b) **Geographic Information Systems**

Our GIS analysts provided analysis and processing of map products incorporating utility asset data to inform proceeding documents and recommendations. We also supported the OIR mandated ignition reporting and contributed to the development of the “Wind Exceedance Map” for the Fire Prevention Plan.

This work included development and impact analysis for the interim Fire Map 1. Our GIS team also played a significant role in the development, review and refinement of Fire Map 2.

c) **REAX Engineering**

From 2014-2018, PG&E, with other California Utilities and the Communication Infrastructure Providers, contracted with REAX Engineering to support wildland fire risk modeling, mapping and computational analytics. REAX Engineering

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32 An accounting credit was applied in 2018.

33 The early development work of our FPI using the POMMS model is discussed in detail in PG&E’s EPIC 1.05 project report: https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.05.pdf.

supported Fire OIR efforts and acted as a co-lead (with SDG&E and PG&E) to develop Map 2, which resulted in Commission adoption of the statewide HFTD Map in 2018. Costs accrued for this activity reflect our payments made directly to REAX Engineering.

2) Reason for Activity

Our contributions to the development of the statewide fire map were made as part of a process established by the CPUC in R.08-11-005, and continued in its successor, R.15-05-006. These proceedings addressed: (1) the development and adoption of a statewide fire-threat map that delineates the boundaries of HFTD areas where the new regulations will apply; (2) the assessment of the need for additional fire-safety regulations in the HFTD areas; and (3) the revision of GO 95 to define HFTD areas and impose new fire-safety regulations.

c. Increased Inspections and Associated Tree Work in "HFTD Areas"

D.17-12-024 required increased vegetation clearances from high voltage lines in Tier 3 areas by September 1, 2018 and in Tier 2 and Zone 1 by June 30, 2019. The activities described below were those necessary to comply timely with these standards. Future continued compliance costs are captured in our Routine Vegetation Management Program described in the GRC and are separate from this request.

1) Nature of Activity

In 2018 and 2019, we spent approximately $1.8 million on contractor costs for inspection and tree work to comply with General Order 95, Rule 35 (revised in Dec 2017) in the newly-established HFTD areas. Contractor costs associated with an accelerated schedule and the tree work to implement the new requirements are shown in Table 2-24.

TABLE 2-24
INCREASED INSPECTIONS AND ASSOCIATED TREE WORK EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Activity	Account	MAT	2018 Expense	2019 Expense
1	Increased Inspections and Tree Work	FHPMA	IG#	$1,763	$2

By 2018, the HFTD Map encompassed about 30 percent of PG&E's overhead distribution line miles, greatly expanding PG&E territory requiring increased clearances. General Order 95, Rule 35 (revised in December 2017) expanded the tree clearance requirements in these designated areas from 18 inches to 48 inches. Prior to this expansion, we maintained the 48-inch tree clearance requirement in State Responsibility Areas[34] and in Santa Barbara County per Public Resources Code 4293 and GO 95, Rule 35.

2) Reason for Activity

The new HFTD areas resulted in one-time incremental costs necessary to comply in the expanded areas with the revised General Order 95, Rule 35. D.17-12-024 increased clearance requirements in newly defined HFTD areas. We implemented an accelerated schedule of inspections and increased tree work to meet the increased clearance requirements. The Decision required compliance in Tier 3 by September 1, 2018, and in Tier 2 and Zone 1 by June 30, 2019.

3) Location and Timing of Activity

We conducted inspection and associated tree work as described above in HFTD areas in 2018 and 2019. We completed the necessary work on or ahead of the dates required for compliance.

4) Personnel and Contractor Costs

PG&E employees spent approximately 470 hours to support this inspection and associated tree work to comply with D.17-12-024.

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[34] State Responsibility Areas are defined in the California Public Resources Code 4125.

To facilitate the increased inspections and tree work, we retained additional pre-inspectors and tree crews from contracted companies, and sourced new contracts. We also incurred costs for overtime compensation to tree crews, needed because of the limited vegetation management resources available in California. Overtime was incurred for a portion of the work to ensure timely compliance with the new regulations.

d. Fuel Reduction, Accelerated Wildfire Risk Reduction, and Enhanced Vegetation Management Programs

After 2017, due to increased wildfire risk in PG&E's service territory, we increased our wildfire risk mitigation efforts, bearing in mind what we had learned about climate change in recent years and from the 2017 Northern California fires. We augmented the scope of our tree work and prioritized work in high wildfire risk locations. The added work generally focused on removing branches overhanging the conductors, and evaluation and removal of trees near and within striking distance of the overhead distribution facilities.

This work went well beyond our Routine Vegetation Management activities, which focused on performing tree work on all circuits to assure clearance requirements were met and dead or dying trees were addressed, or the CEMA drought response program, in which we worked dead or dying trees (due to the drought) in fire prone areas. The work discussed herein is incremental to the more than one million trees our Routine Vegetation Management programs historically have worked or removed annually, and those charged to the CEMA Program.

The incremental risk reduction work, which we performed as part of Fuel Reduction Program, then through Accelerated Wildfire Risk Reduction, and finally as the Enhanced Vegetation Management Program, often exceeded compliance requirements.

The recorded incremental costs for these programs are presented in Table 2-25 below.

TABLE 2-25
VEGETATION MANAGEMENT PROGRAM EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Program	Account	MAT	2018 Expense	2019 Expense
1	Fuel Reduction Program	FHPMA	IG#	$35,634	$1,975
2	Accelerated Wildfire Risk Reduction	FHPMA	IG#	269,015	26,058
3	Enhanced Vegetation Management	WMPMA	IG#		449,502
4	Total Programs			$304,649	$477,535

1) Reason for Activities

D.17-12-024 greatly expanded the geographic areas defined as HFTD areas in PG&E's service territory. These areas, particularly Tier 3 areas, require greater conductor clearances. The Decision further required the creation and implementation of a Fire Prevention Plan for an electric IOU's overhead electric facilities in the HFTD areas. The Fire Prevention Plan must include a description of "the electric corporation's strategies and programs to reduce the risk of its electrical lines and equipment causing catastrophic wildfires."[35]

To further the Fire Prevention Plan, we created the Fuel Reduction Program, which evolved into its successor, our Accelerated Wildfire Risk Reduction approach. Our Accelerated Wildfire Risk Reduction work then evolved into the Enhanced Vegetation Management Program, the scope of which was informed by knowledge we gained during the Fuel Reduction Program and Accelerated Wildfire Risk Reduction approach regarding the breadth of tree work needed in the HFTD areas, the database support needed, and environmental and customer concerns—as well as the need to continue to address fire risks in HFTD areas.

We initiated the first of these programs—the Fuel Reduction Program—to support our Fire Prevention Plan and in response to the Commission's modification of GO 95, Rule 35 in D.17-12-024. Accelerated Wildfire Risk Reduction likewise supported the Fire

35 D.17-12-024, p. 27.

Prevention Plan, as well as the anticipated WMP, and addressed the expanded definition of HFTD areas in D.17-12-024.

Subsequently, on August 31, 2018, the California Legislature passed SB 901. Among other measures, SB 901 mandated that electric IOUs with lines or equipment in HFTD areas annually submit a comprehensive WMP to the CPUC. SB 901 laid out specific requirements for an annual WMP, including the timing and process for cost recovery for work conducted pursuant to a WMP.

We submitted our first WMP on February 6, 2019, which the CPUC approved on May 30, 2019 in D.19-05-037. This Decision authorized PG&E to track incremental wildfire-related costs incurred while implementing approved programs under the WMP. The Enhanced Vegetation Management Program activities discussed below reflect the implementation of work proposed in PG&E's 2019 WMP and approved in in D.19-05-037.

Separately, R.18-10-007 required PG&E to modify its approach to mitigating the wildfire risk posed by healthy trees with the potential to fall into conductors. We responded to 18-10-007 by proceeding with the increased clearance and overhang removal components of the Enhanced Vegetation Management Program scope, but suspended removal of healthy trees based on species alone. Tree evaluations expanded to a detailed inspection of all trees tall enough to strike using a previously-established Hazard Tree Rating System.

2) Fuel Reduction

a) Nature of Activity

The Fuel Reduction Program focused on reducing all vegetative fuels in the area at a horizontal distance of 15 feet on either side of the line between two poles, with the intention of reducing wildfire risk in the highest risk areas. One can analogize to the work we perform on many of PG&E's transmission rights-of-way (ROW): that is, the Fuel Reduction

Program goal was to clear all vegetation growing around distribution facilities in the highest risk HFTD areas.

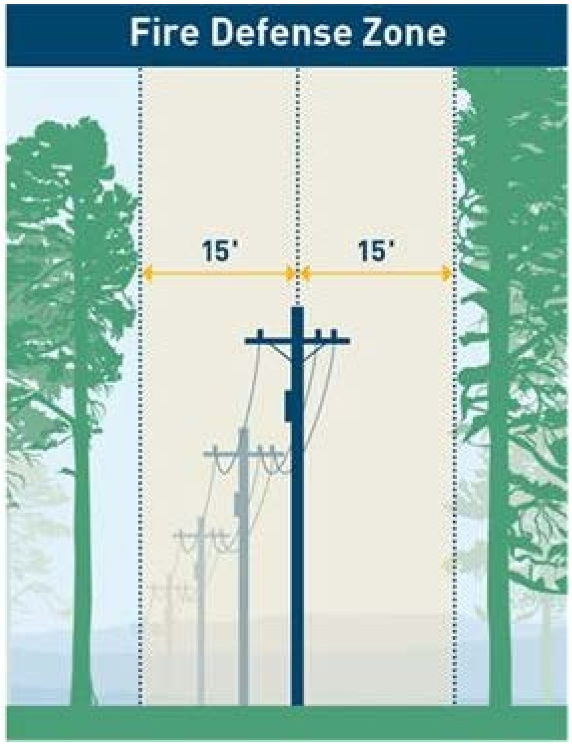
This effort was well beyond anything that had ever been done on the distribution system on a large scale. In our Routine Vegetation Management Program, typical distribution line work involves pruning or removing only those trees that would present a compliance concern within the coming year. The Fuel Reduction Program greatly expanded the scope of distribution line work to include all trees near the lines, not just those that were a near-term compliance concern.

This work created “Fire Defense Zones” that:

- Create safe space between power lines and trees and brush that can act as fuel for wildfires;
- Help to slow the spread of fires and improve access for first responders in the event of a wildfire; and
- Enhance defensible space around homes, businesses, and properties, thereby improving safety.

See Figure 2-16 for an illustration of the program activity scope.

FIGURE 2-16
FUEL REDUCTION PROGRAM SCOPE



b) Location and Timing of Activity

We began the Fuel Reduction Program in HFTD areas in March 2018 and concluded it in August 2018, subject to a relatively small amount of work in 2018 that was paid to contractors in 2019. The work involved clearing vegetation near the power lines in Tier 3 areas. We conducted the work in five of the six regions of PG&E's service territory.

Table 2-26 illustrates the number of cleared miles by PG&E Division.

TABLE 2-26
MILES CLEARED TO FUEL REDUCTION PROGRAM SCOPE

Line No.	Division	Miles
1	Bay	15
2	Central Coast	–
3	Central Valley	95
4	North Coast	6
5	North Valley	19
6	Sierra	5
7	Total	140

c) Personnel and Contractor Costs

PG&E employees worked approximately 10,200 hours as part of the Fuel Reduction activities performed in 2018 and 2019. The cost per mile was about $271 thousand.

The Company hired contractors to work as pre-inspectors responsible for inspecting electric facilities and identifying the vegetation to be mitigated as part of the Fuel Reduction Program. During the peak of the program, PG&E used about 200 pre-inspectors to mark the vegetation to be mitigated, record data, and communicate with customers. Because of the limited vegetation management resources available in California at the time, PG&E incurred overtime for a portion of the work to achieve timely compliance with the new regulations and program scope.

PG&E also engaged contractors to complete the tree work identified by pre-inspectors. PG&E used approximately 400 tree crew personnel, along with a variety of mechanical equipment, during the peak of the Fuel Reduction Program.

In 2018 and 2019,[36] PG&E spent approximately $38 million on these Fuel Reduction Program activities as shown in Table 2-27 below.

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[36] Even though pre-inspection work stopped in August of 2018, work continued to be completed and contractors issued invoices into 2019.

TABLE 2-27
FUEL REDUCTION PROGRAM EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Activity	Account	MAT	2018 Expense	2019 Expense
1	Fuel Reduction	FHPMA	IGJ	$35,634	$1,975

3) Accelerated Wildfire Risk Reduction

In September 2018, we transitioned from the Fuel Reduction Program into the Accelerated Wildfire Risk Reduction emergency response effort. Accelerated Wildfire Risk Reduction efforts also mainly focused on Tier 3 HFTD areas, but the program scope required greater radial clearances around conductors and removed vegetation above and beneath conductors (ground to sky clearance).

Our Accelerated Wildfire Risk Reduction activities included:

- Mitigation of hazardous trees with potential to strike PG&E facilities, including: (1) danger trees; (2) trees with poor taper; (3) trees with poor height to crown ratio; and (4) suppressed trees, in accordance with GO 95, Rule 35 and PRC 4293; inspection of the trees in right of way or targeting overhead conductors and mitigation of trees requiring work; and reduction of the potential for overhanging branches to fail and contact primary voltage lines.
- Reduction of fuel underneath and adjacent to high voltage lines (with property owner cooperation).
- Wood Management: To help avoid costly delays and ensure timely mitigation of trees with potential to impact PG&E facilities, Accelerated Wildfire Risk Reduction included wood removal for customers free of charge.[37]

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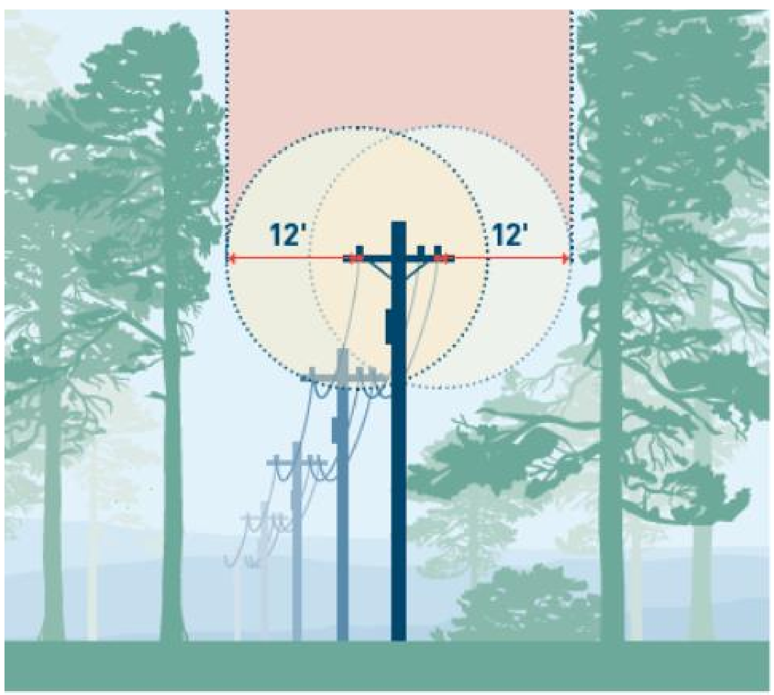
[37] Some customers objected to tree removal unless the entire tree was removed from their property. Others preferred to keep the wood for personal use. The rest received a Request for Wood Management form at the time of inspection, which was also available online at pge.com/enhanced veg. When PG&E received a request form, it scheduled the wood debris for removal from the property after completing the tree work.

- LiDAR (Light Detection And Ranging[38]): PG&E gathered LiDAR data in HFTD areas to identify trees within strike distance of the electric lines. PG&E also used this data to identify accurately the scope of tree work needed in HFTD areas.
- Safety oversight: We increased the safety oversight of the contractors that performed the tree work. Safety inspectors audited work in progress to help ensure safe working conditions and adherence to safety protocols.
- Other Support: Our other support activities included the establishment of the Incident Command Center and base camps, onboarding and training of contractors, customer communications in association with tree work on customer property and wood removal.

FIGURE 2-17
ACCELERATED WILDFIRE RISK REDUCTION PROGRAM SCOPE



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38 LiDAR is a remote sensing method that uses light in the form of a pulsed laser to measure ranges (variable distances) to the Earth. These light pulses—combined with other data recorded by the airborne system—generate precise, three-dimensional information about the shape of objects and distances from each other.

a) Timing and Location

Accelerated Wildfire Risk Reduction was a short-term approach implemented primarily from September to December 2018, with some work moving into 2019 for various reasons. As part of this work, we brought on additional contractors to address quickly fire risks in the HFTD areas. Table 2-28 reflects the number of miles completed during our Accelerated Wildfire Risk Reduction work.

TABLE 2-28
MILES COMPLETED TO ACCELERATED WILDFIRE RISK REDUCTION SCOPE

Line No.	Division	Miles
1	Bay	110
2	Central Coast	48
3	Central Valley	225
4	North Coast	134
5	North Valley	38
6	Sierra	66
7	Total	621

b) Personnel and Contractor Costs

PG&E personnel across multiple lines of business spent a total of approximately 103,200 hours in support of Accelerated Wildfire Risk Reduction activities. The work cost approximately $556 thousand per mile.

PG&E used contractors as pre-inspectors for electric facilities in order to identify issues within the scope of Accelerated Wildfire Risk Reduction parameters. During the peak of the work, PG&E tasked over 370 pre-inspectors with marking the vegetation to be mitigated, recording data, and communicating with customers.

We used tree crew contractors to complete the tree work identified by pre-inspectors. During the peak of the program, we dedicated over 1,760 tree crew personnel, along with a variety of mechanical equipment, to Accelerated Wildfire Risk Reduction projects.

PG&E implemented this work from a command center in San Ramon, CA and managed it with an Incident Command System structure with base camps throughout the HFTD areas. After we sourced contractors and put initial procedures in place, we decentralized the program though the local Vegetation Management Program and coordinated it locally under the Enhanced Vegetation Management Program, which was the next, and more permanent stage in the evolution of our Vegetation Management work dedicated to wildfire mitigation in HFTD areas.

We spent $295 million for Accelerated Wildfire Risk Reduction activities and tree work completed in 2018 and 2019, as shown below in Table 2-29.

TABLE 2-29
ACCELERATED WILDFIRE RISK REDUCTION EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Activity	Account	MAT	2018 Expense	2019 Expense
1	Inspection and Tree Work			$180,029	$7,061
2	Wood Management			28,858	4,922
3	LiDAR			2,620	560
4	Safety			16,728	8,870
5	Other Support			40,780	4,646
6	Total – Accelerated Wildfire Risk Reduction	FHPMA	IGJ	$269,015	$26,058

4) Enhanced Vegetation Management

We created the Enhanced Vegetation Management Program in December 2018 as an expansion of, and more sustainable replacement for, our short-term and urgent Accelerated Wildfire Risk Reduction work. We defined the parameters of this program based on what we learned from the Fuel Reduction Program and our Accelerated Wildfire Risk Reduction work. Our Enhanced Vegetation Management Program includes a long-term plan to address all high voltage lines in the HFTD areas, which refines the scope of work adjacent to and within striking distance of conductors.

We also modified our approach so that we evaluated all trees with the potential to strike the conductors, not just removal of the top 10 species with a historical tendency to do so.

a) Nature of Activity

Our Enhanced Vegetation Management Program refined the scope and approach of our Accelerated Wildfire Risk Reduction work (with respect to radial clearance zone, targeted tree species, LiDAR, wood management, safety oversight and other support work) and, in order to achieve effective mitigation criteria, exceeded regulatory requirements in some respects. The following describes aspects of the program:

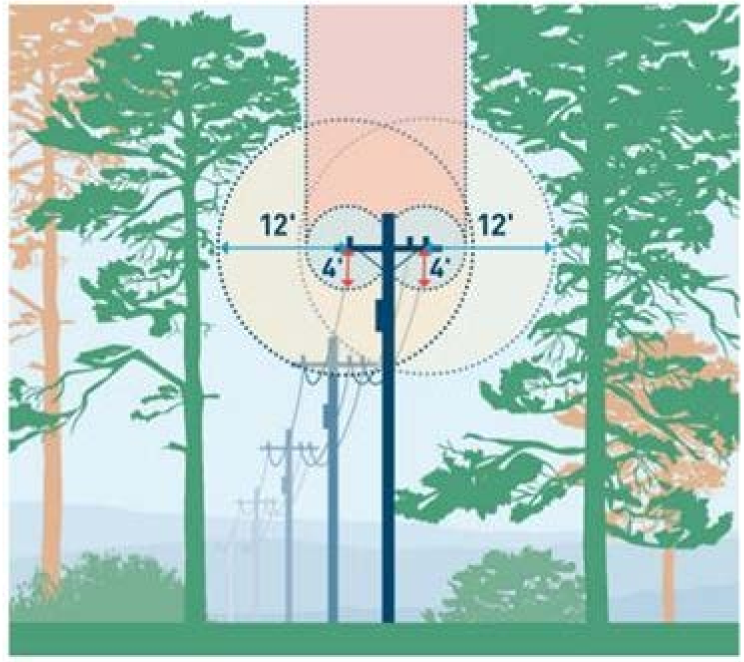
- Overhang Clearing: We removed overhanging branches and limbs directly above but *beyond* the radial clearance zone around electric power lines required by regulatory requirements in order to further reduce the possibility of wildfire ignitions or downed wires due to vegetation-conductor contact from tree limbs.
- Targeted Tree Work: We evaluated and trimmed or removed specific tree species within the fall or strike zone of power lines that are more likely to fail, and addressed dead or dying trees. We modified this work in mid-2019 to include an evaluation of *all* trees with the ability to strike the electric facilities, rather than just targeted tree species.
- Magnitude: The scale (approximately 25,200 distribution circuit miles in HFTD areas), scope, and complexity of this work necessitated a multi-year program.
- Other Support: Our other support activities included base camp siting and development for tree workers and pre-inspectors in the field, and coordination with and strategic partnerships with local, state, and federal land managers.

Initially, our Enhanced Vegetation Management Program continued our focus on the removal or trimming of the top 10 high risk species of trees with high failure rates that could fall into the lines. But our analysis determined that other tree species were also showing signs of weakness and decay. This led us to expand the Enhanced Vegetation Management Program inspections to include all trees that are tall enough to strike overhead distribution facilities, have a clear path to strike, and exhibit other potential risk factors, such as leaning toward a line.

As a result, our Enhanced Vegetation Management Program assessed all trees tall enough to strike a line and removed all branches above that line. These changes expanded the scope of vegetation management work we performed in HFTD areas. Trees often exceed 150 feet in height, so this greatly expanded the population of trees subject to detailed review by the pre-inspectors.

Figure 2-18 below illustrates the scope of the Enhanced Vegetation Management Program in 2019 (and today). The healthy branches in the pink area above the lines would not have required work under the Routine program but are now being addressed by the Enhanced Vegetation Management Program. Also, the tall trees to the sides of the lines that are now evaluated by the Enhanced Vegetation Management Program would not have been evaluated under the Fuel Reduction Program or our Advanced Wildfire Risk Reduction work.

FIGURE 2-18
ENHANCED VEGETATION MANAGEMENT PROGRAM SCOPE



In 2019, we further trimmed or removed vegetation along 2,498 distribution line-miles within HFTD areas as part of the Enhanced Vegetation Management Program. In addition, we trimmed or removed approximately 202,000 trees.

PG&E also performed these Enhanced Vegetation Management activities in United States Forest Service (USFS) territory. In 2019, PG&E and USFS developed a roadmap—the Programmatic Operations and Maintenance Plan (O&M Plan)—to describe the facilities and vegetation management work required to address potential wildfire hazards in Tier 2 and Tier 3 areas on USFS land within PG&E's service territory. The O&M Plan defines the environmental review and protection process and establishes the activity review process and communication and monitoring protocols for future Vegetation Management mitigation work on USFS land. Once the plan was agreed upon, we entered into a strategic partnership with the USFS to perform fire risk reduction work in eleven USFS forests within PG&E's territory. In 2019, USFS staff reduced fuel loads in areas adjacent to and around our facilities in Tier 2 and Tier 3 areas within four USFS forests.

b) Location and Timing of Activity

We created the Enhanced Vegetation Management Program in December 2018 as an expansion of, and more permanent replacement for, our Accelerated Wildfire Risk Reduction work.

We removed or trimmed approximately 202,000 trees in 2019 as part of the Enhanced Vegetation Management Program. See Table 2-30 for the number of distribution line-miles we completed to Enhanced Vegetation Management scope within HFTD areas.

TABLE 2-30
MILES COMPLETED TO ENHANCED VEGETATION MANAGEMENT SCOPE

Line No.	Division	Miles
1	Bay	232
2	Central Coast	360
3	Central Valley	630
4	North Coast	584
5	North Valley	398
6	Sierra	295
7	Total	2,498

c) Personnel and Contractor Costs

PG&E contractors spent a total of approximately 84,200 hours in support of the Enhanced Vegetation Management Program in 2019.

The tables below illustrate the tree crew staffing levels, as well as pre-inspection staffing levels during the peak of the program.

FIGURE 2-19
2019 ENHANCED VEGETATION MANAGEMENT TREE CREW STAFFING

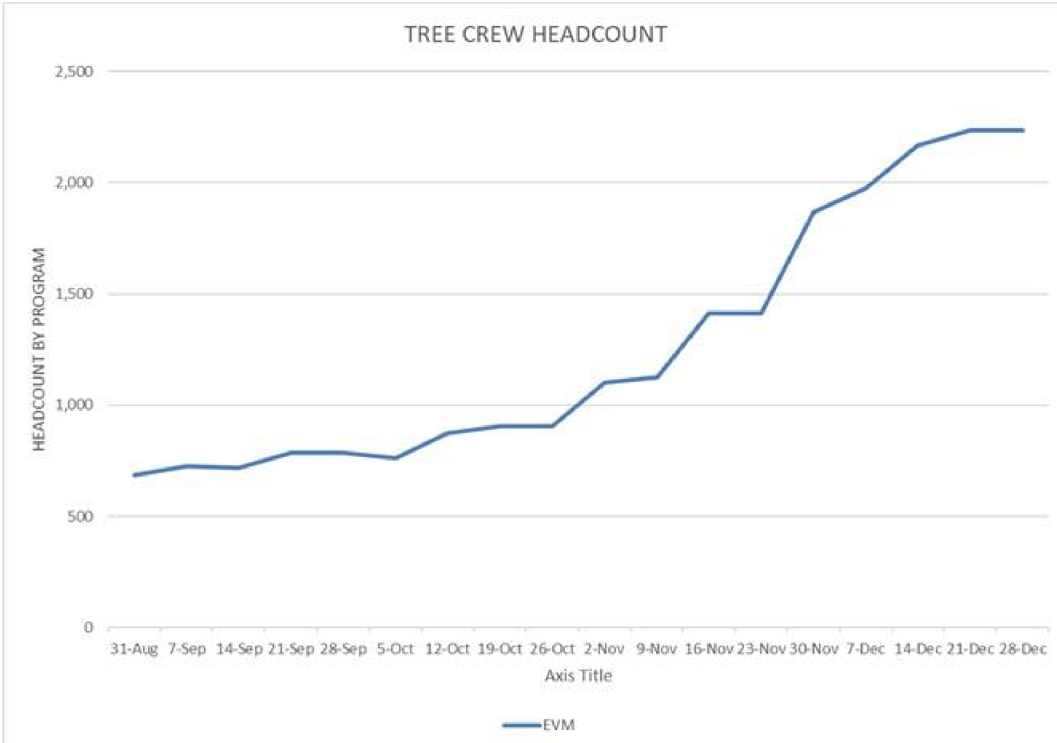
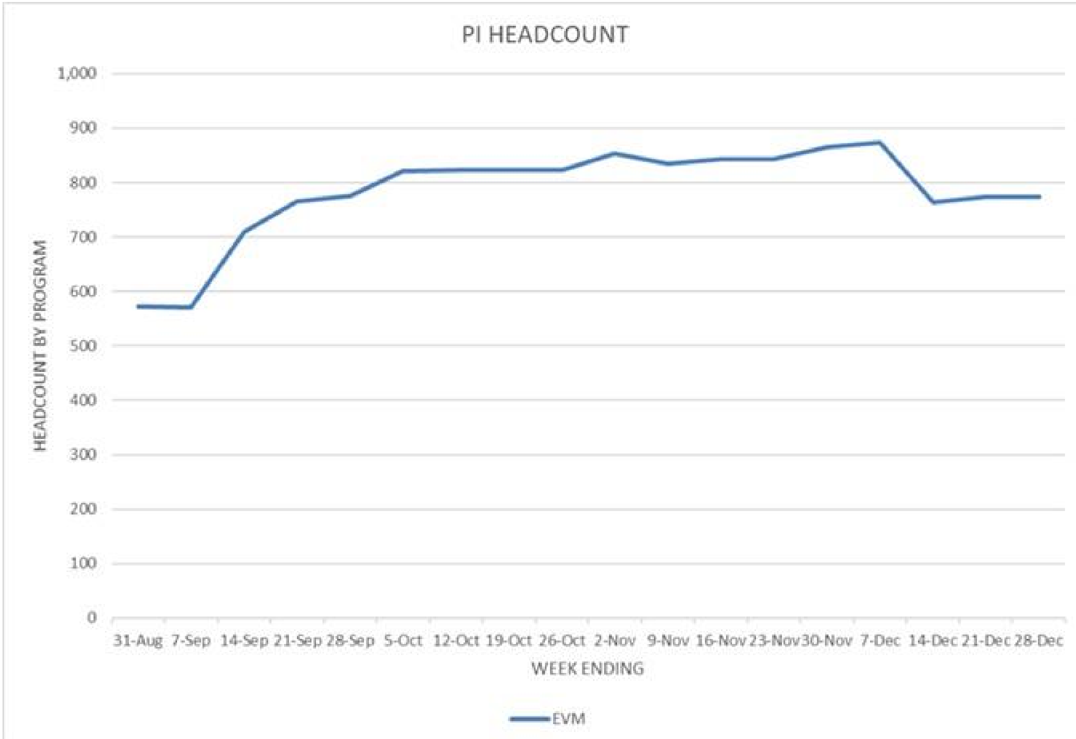


FIGURE 2-20
2019 ENHANCED VEGETATION MANAGEMENT PRE-INSPECTION STAFFING



The cost per mile to complete Enhanced Vegetation Management Program work for 2019 was approximately $177 thousand per mile. This reflected the dense tree conditions in Northern California in the HFTD areas and our adjustment to the program scope based on lessons learned from the Fuel Reduction Program and our Accelerated Wildfire Risk Reduction work.

We experienced increases in contractor costs at a rate higher than normal in 2019. In addition to normal inflationary increases, contractors passed on increased insurance costs due to the fire dangers in California. Costs also increased because of a shortage of supply created by the depleted contractor pool in the state. At the same time, the volume of difficult work increased because the scope and difficulty of the Vegetation Management work occurring our territory and in the state. Contractors passed these increased costs to us through the rates they charged.

We spent approximately $443.9 million on Enhanced Vegetation Management Program activities in 2019 as shown in Table 2-31.

TABLE 2-31
ENHANCED VEGETATION MANAGEMENT EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Activity	Account	MAT	2019 Expense
1	Inspection and Tree Work			$284,555
2	Wood Management			63,487
3	LiDAR			26,487
4	Safety			31,083
5	Other Support			43,889
6	Total Enhanced Vegetation Management	WMPMA	IGJ	$443,914

4. Situational Awareness, Forecasting, and Support

The nine Situational Awareness, Forecasting, and Support activities addressed in this section are grouped into five general categories, as shown in the table below.

TABLE 2-32
SITUATIONAL AWARENESS, FORECASTING, SUPPORT ACTIVITIES
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	Community Wildfire Safety Program (CWSP) Program Management Office (PMO)	$33,092	$92
2	Expanded Weather Station Deployment; Wildfire Cameras; Sensor IQ	2,721	6,932
3	Advanced Fire Modeling; Wind Loading	4,169	3,828
4	Wildfire Safety Operations Center (WSOC)	4,708	2,290
5	Safety and Infrastructure Protection; SmartMeter Partial Voltage Detection	0	1,018
6	Total	$44,690	$14,160

Each activity is discussed in more detail below.

a. Community Wildfire Safety Program – Program Management Office

TABLE 2-33
COMMUNITY WILDFIRE SAFETY PROGRAM
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	Community Wildfire Safety Program – Program Management Office	$33,092	$92

1) Nature of Activity

In 2019, we spent $33.2 million to set up the Program Management Office (PMO) for our newly-established Community Wildfire Safety Program (CWSP). The CWSP is responsible for implementing the mitigation initiatives outlined in our 2019 WMP. The PMO leads and facilitates the overall CWSP, developing and optimizing mitigation programs in conjunction with external resources, establishing metrics to track wildfire mitigation efforts, and coordinating implementation across multiple lines of business.

The PMO's responsibilities also include monitoring progress, handling resourcing needs, and directing workstreams as issues arise. With the unprecedented ramp up in 2019 of new programs designed to address wildfire risk, we deployed substantial resources through the PMO to establish quality monitoring programs, data and metric tracking, program documentation, and other programmatic activities.

To address the significant impact of the CWSP, and its new mitigation programs, on our customers, the PMO also supports internal and external engagement efforts, including public affairs and government relations support, local customer outreach support, and marketing and communications for the program overall. In 2019, our external outreach for the CWSP program included open houses, webinars, and meetings with local councilmembers to educate customers about wildfire risks, PG&E's wildfire risk mitigation activities, and PSPS events.[39]

In the wake of previous utility-caused wildfires, the external oversight and interest in PG&E's wildfire mitigation activities was, understandably, considerable in 2019. The CWSP PMO facilitated and led the reporting, updates, and engagement with outside parties. The PMO led these external reporting and engagement activities to allow the operational leaders of the CWSP workstreams to focus, to the maximum extent possible, on the actual wildfire risk mitigation activities they were tasked with leading.

Our 2019 spending for the CWSP PMO represents start-up costs associated with establishing an ongoing PMO, developing processes for CWSP workstreams, and engaging third party resources to support and analyze potential mitigation initiatives and facilitate external engagement efforts. The cost of our 2019 PMO activities (over $30 million) represents an investment of less than 2 percent of the total CWSP spend (over $1,500 million) in the governance, tracking, coordination, education, and communication activities needed to help ensure the effective deployment of the wildfire risk mitigation programs within the CWSP.

2) Reason for Activity

SB 901 required each publicly-owned California utility to submit an annual WMP to establish the utility's approach to mitigating wildfire risk caused by its electric equipment. The comprehensive CWSP delivers on the key facets of our 2019 WMP. The PMO, in turn, is a foundational support, tracking, and governance structure needed to effectively start-up, execute, and manage the CWSP across multiple work streams.

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39 The PSPS customer outreach costs described here are distinct from the similar costs described in the PSPS section of this chapter and were tracked separately. The CWSP PMO performed high-level wildfire outreach that included general information about PSPS. In contrast, the outreach described in the PSPS section was primarily focused on preparing customers for PSPS events.

In 2019, the CWSP PMO supported the accelerated implementation of CWSP workstreams ramping up to unprecedented levels of activity by providing programmatic support and flexible resources across multiple workstreams. Other overall benefits of the CWSP PMO include:

- Improved oversight via a centralized entity that oversees strategy and execution;
- Alignment of work tracking, quality management, documentation and other processes through a centralized team;
- Improved accountability through dedicated resources focused solely on the wildfire program;
- Improved external outreach, coordination, and engagement of stakeholders and customers on the full suite of our wildfire risk mitigation activities; and
- Improved change management and coordination due to the cross-functional nature of the wildfire program, which incorporates many lines of business across PG&E and multiple functional groups within Electric Operations.

3) Location and Timing of Activity

The PMO supports wildfire mitigation activities throughout PG&E's service territory, primarily in HFTD areas. The PMO coordinates with state lawmakers and regulators and performs community outreach throughout the State.

We created the CWSP PMO in August 2018 to develop and implement mitigation initiatives within our 2019 WMP. Costs associated with standing-up the PMO and the CWSP mitigation programs were largely borne in 2019.[40] The PMO supported a diverse collection of tasks and activities in 2019, as our first WMP was developed, submitted, and implemented through the CWSP. The growing information about, and awareness of, the magnitude and complexity of the wildfire risk facing PG&E and the state, including as reflected in legislative changes, drove the rapid

40 This application only seeks recovery for costs incurred in 2019.

implementation of the wildfire risk mitigation programs and, accordingly, the PMO structure and processes needed to facilitate that work in 2019. While the PMO will continue to manage and oversee the CWSP going forward, we anticipate significantly lower costs in future years, as the start-up costs have largely been incurred for both the PMO and the individual wildfire risk mitigation workstreams within the CWSP.

4) Personnel and Staffing of Work

The PMO is made up of a combination of internal and contract resources. In 2019, one PG&E employee was dedicated to overseeing the overall PMO delivery, with additional employees assisting as needed. In standing up the PMO, and the CWSP workstreams, we supplemented internal resources with outside vendors for three primary reasons: (1) to leverage the broad knowledge and skills of outside resources; (2) to enable the swift action required to reduce wildfire risks in the near term; and (3) in recognition of the fact that a sizeable permanent staff was not needed, and a sustainable, long-term staffing level could be determined after start-up activities were complete. As noted above, we anticipate significantly lower costs for a primarily internally-staffed PMO to continue to manage, govern, and support the CWSP workstreams going forward.

In 2019, we worked with four vendors in different capacities. The first vendor supported stakeholder engagement activities including community open houses, customers, and stakeholder awareness materials; supported program documentation for internal and external users; facilitated cross-functional meetings, alignment, and work activities; and supported weekly work tracking of CWSP workstreams for reporting out with PG&E leadership.

Another vendor supported workstream start-up activities in multiple programs including the Wildfire Safety Inspection Program (WSIP) and incremental Vegetation Management activities; established work tracking and governance tools for specific workstreams like the WSIP as the workstreams ramped up in real-time; and developed dashboards for ongoing tracking of workstream progress and quality performance.

A third vendor supported risk analysis and quantification processes to inform decision-making and prioritization of multiple workstreams, including System Hardening and Vegetation Management; and supported documentation of CWSP programs, including for GRC filings related to wildfire risk mitigation programs and the 2019 WMP.

Finally, the fourth vendor supported the drafting and submission of the 2019 WMP, as well as the discovery phase of that proceeding; facilitated overall CWSP program development, including governance processes and tracking and reporting tools; and contributed to the development of program materials for internal and external information sharing, decision making, and communication.

b. Weather Stations, Cameras, and Sensors

This category of work embraces three types of activities, shown in the table below: (1) Expanded Weather Station Deployment; (2) Wildfire Cameras; and (3) Sensor IQ.

TABLE 2-34
WEATHER STATIONS, CAMERAS, SENSORS
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	Expanded Weather Station Deployment	$606	$6,932
2	Wildfire Cameras	2,063	–
3	Sensor IQ	53	0
4	Total	$2,722	$6,932

Each activity is discussed in more detail below.

1) Expanded Weather Station Deployment

Our 2019 costs for Expanded Weather Station Deployment are shown in the table below.

TABLE 2-35
WEATHER STATIONS
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	Expanded Weather Station Deployment	$606	$6,932

a) Nature of Activity

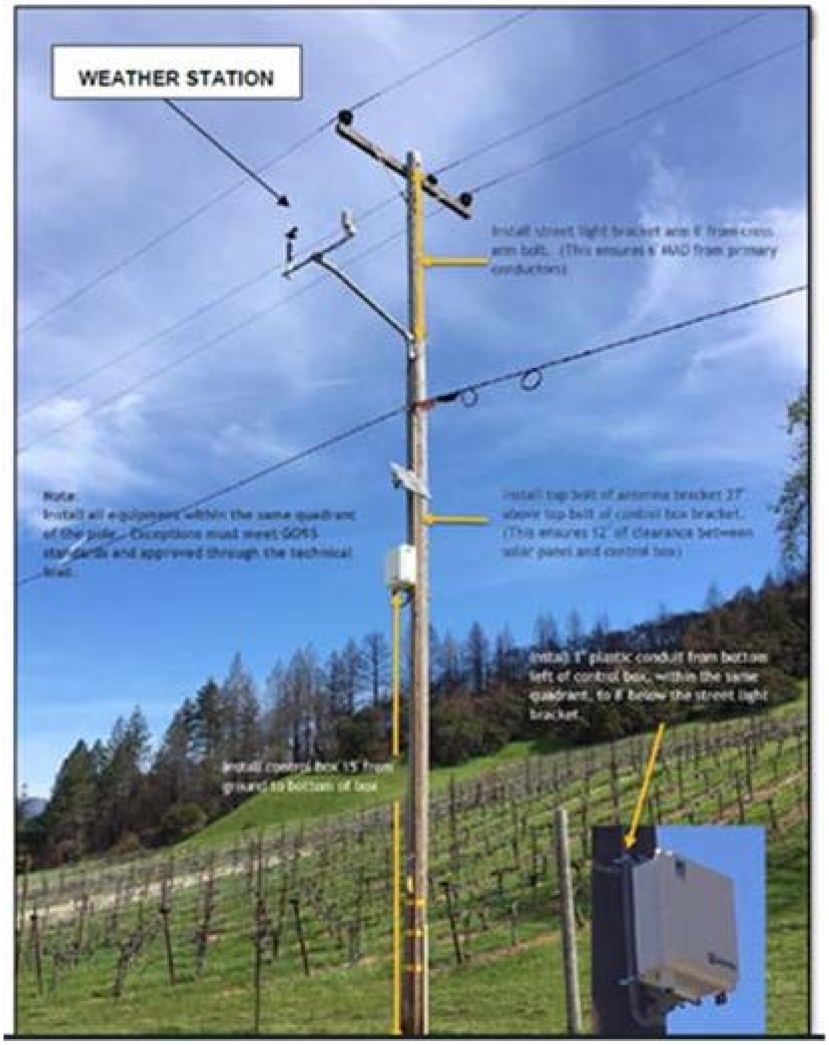
We spent $7.5 million in 2019 to install 426 new weather stations and maintain our existing 200, which together comprise the largest utility-owned and operated weather station network in the world.

Each PG&E weather station includes a suite of instruments to measure temperature, wind speed, and humidity, the three most important fire weather parameters. The weather stations also include a Data Collection Platform/Remote Terminal Unit, battery, and solar panel. The devices must be calibrated regularly beginning one year after installation.

The weather stations record and report meteorological data every 10 minutes. The public can access the data in real-time through the National Weather Service (NWS) weather and hazards data viewer, Mesowest, the National Center for Environmental Prediction Meteorological Assimilation Data Ingest System, and at www.pge.com/weather.

The unit cost per weather station in 2019 was $16,272, comprised of materials and hardware, design engineering, site selection and inspection, pole load calculations, installation, and project management. Related 2019 costs included labor, a vendor data contract, communications line leases, and other contract and material costs.

FIGURE 2-21
PG&E WEATHER STATION AND ASSOCIATED INSTALLATION DETAIL



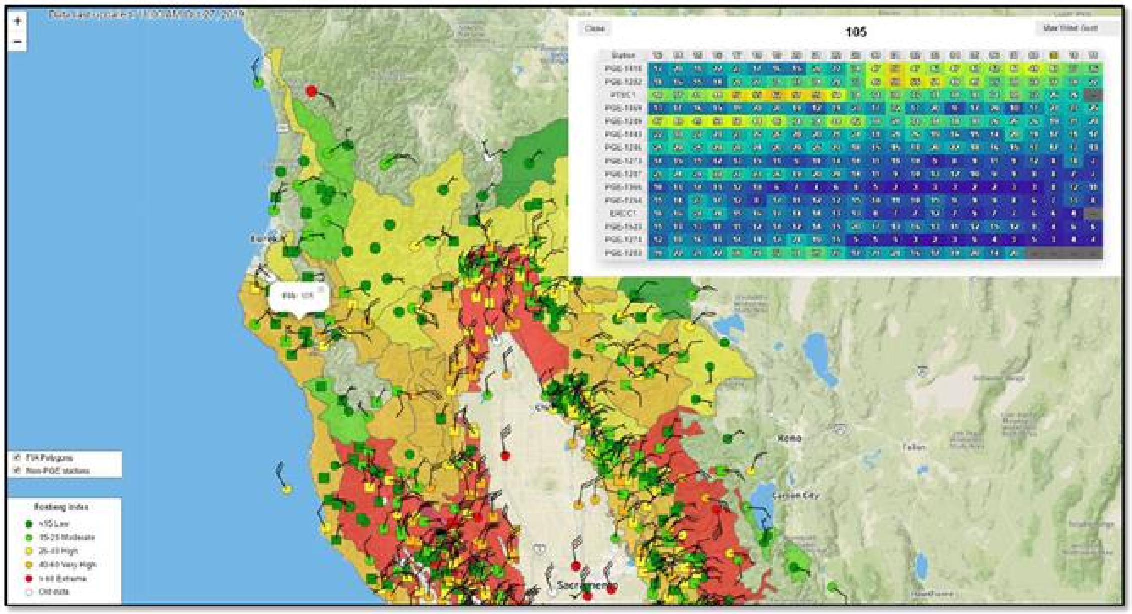
b) Reason for Activity

Our robust weather station network provides continuous, localized weather information that facilitates improved understanding, modeling, and prediction, and real-time awareness of wildfire danger. Weather station data facilitates operational decision-making within the organization, supports the safe operation of our facilities, and informs other mitigations, such as Reclose Blocking and PSPS, that rely on accurate and detailed weather information.

The staff of our Meteorology department uses data from the weather stations to model and monitor real-time weather and fire danger conditions. For example, the weather stations provide data to, and are a key component of, our Advanced Fire Modeling system. We also used the weather stations to help validate and select the best model configuration of our next generation high resolution (2 kilometers (km)) weather model (POMMS).

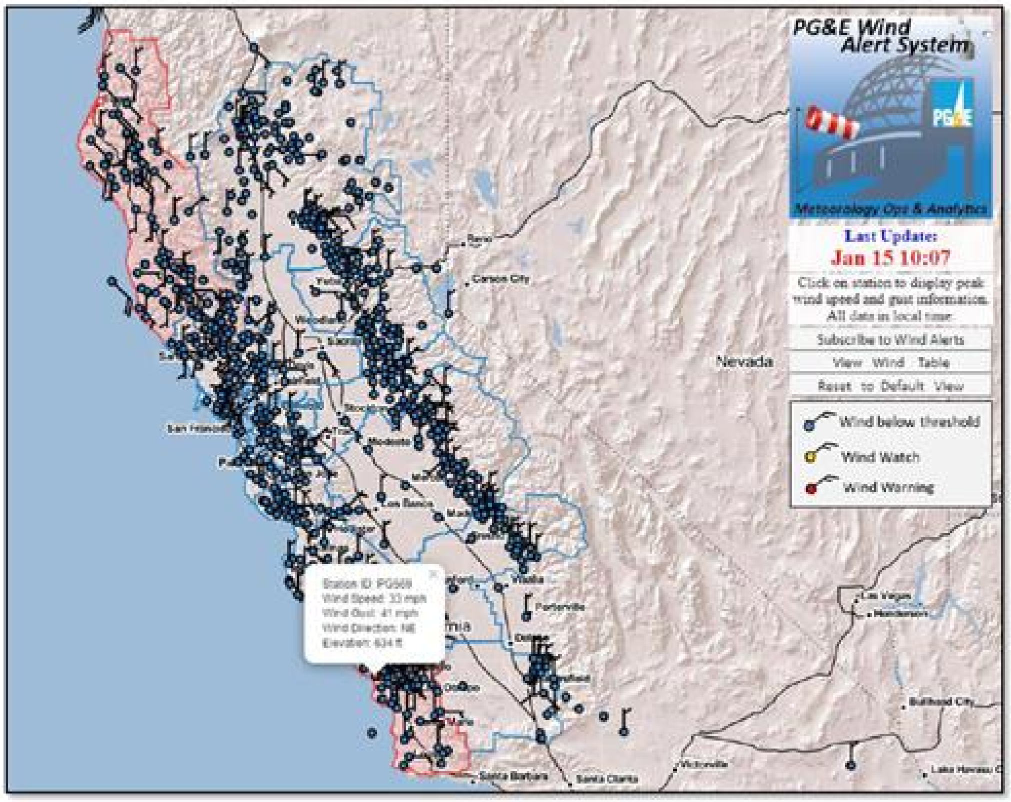
From 2018 into 2019, we developed an internal web application that presents real-time weather station data from multiple networks (PG&E, NWS, Removal Action Work (RAWS)) and color codes the observation based on the Fosberg Fire Weather Index (FFWI) being observed (see Figures 2-22 and 2-23 below). The FFWI is an evaluation of fire weather conditions based on wind speed, temperature, and relative humidity. 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. This real-time information is crucial to determining when the ‘all clear’ can begin following PSPS patrol and restoration.

FIGURE 2-22
INTERNAL WEB APPLICATION DEVELOPED BY PG&E THAT SHOWS REAL-TIME WEATHER STATION DATA FROM MULTIPLE NETWORKS (PG&E, NWS, RAWS)



We also developed the PG&E Wind Alert System, which displays and disseminates alerts when real-time data collected from PG&E, RAWS, and NWS weather stations approach or exceed defined wind criteria. Users can customize the areas for which they receive alerts.

FIGURE 2-23
PG&E WIND ALERT SYSTEM



Note: Displays and disseminates alerts when wind speeds exceed thresholds. Users can customize alerts to only receive alerts for the area(s) needed.

The weather stations also support public agency partners, such as CAL FIRE, NWS, and California Governor's Office of Emergency Services by providing them with critical, real-time fire weather data.

c) Location and Timing of Activity

The weather stations we installed in 2019 are located in Tier 2 and three areas of the CPUC's HFTD Map. Selection criteria included:

- Locations generally above 500' elevation (above 1000' in the Sierras);
- South facing slope or ridge top;
- Good exposure, lack of local vegetation, good "wind fetch";
- Suitable pole, i.e., Class 5 or better; and

- Bucket truck accessible.

We will continue to coordinate with fire agencies regarding placement of the up to 674 additional weather stations we plan to deploy by 2021.

d) Personnel and Staffing of Work

Our Meteorology team led the weather station installation project, with project management help from Emergency Preparedness and Response, Information Technology, and other organizations, and with the help of external contractors. Our 2019 costs included 6,158 hours of employee and contractor labor.

2) Wildfire Cameras

TABLE 2-36
WILDFIRE CAMERAS
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	Wildfire Cameras	$2,063	–

a) Nature of Activity

In 2019, we spent $2.1 million to install 133 high-definition, pan-tilt-zoom cameras to assist with monitoring environmental conditions, confirming fire reports, and charting fire progression. The cameras have near infrared capability to operate in low to no sunlight and are available via a web interface with time lapse functionality. The unit cost per wildfire camera was $15,514, comprised of materials and labor.

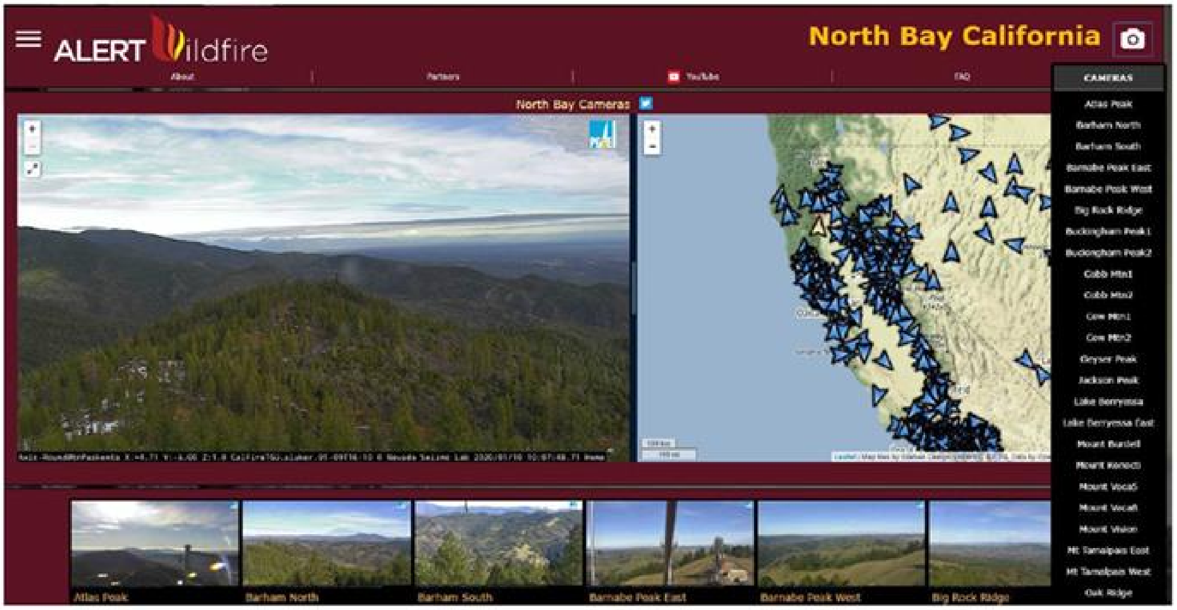
We leverage other technology, such as satellite fire detection data, to help determine which cameras to view and where they should be directed. In the future, we plan to explore cameras that automatically rotate and zoom to view emerging incidents by integrating fire incident reports from the PG&E Fire Detection and Alert System (FDAS).

FIGURE 2-24
EXAMPLE INTEGRATION OF PG&E WILDFIRE CAMERAS AND THE PG&E FDAS

Note: This image of a fire that occurred in the NuStar energy facility in Crockett, California depicts a smoke plume detected by FDAS.

First responders and external agencies like CAL FIRE and the USFS can control the pan, tilt, and zoom features of our cameras to assist with their respective fire response efforts. Live feeds and time-lapse data from our camera network are available to the public at http://www.alertwildfire.org and have often been featured on local newscasts.

FIGURE 2-25
PG&E EXAMPLE CAMERA OUTPUT, WEB INTERFACE, AND CAMERA NETWORK DENSITY



Note: From www.alertwildfire.org.

b) Reason for Activity

Wildfire cameras improve our overall situational awareness and are a valuable tool for assisting the Wildfire Safety Operations Center, first responders, and fire agencies. PG&E and public agencies use the wildfire cameras to identify, confirm, and track wildfires and general conditions in real-time, from ignition to containment. This allows us and other users 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. After wildfire containment, the cameras can provide a watchful eye to ensure the fire does not re-ignite.

While we currently employ a Meteorology team to forecast and study weather, we do not have a dedicated system for early fire detection and alert. By using commercial camera technology, we gain valuable visual intelligence and potential early warning of wildfires that could impact our electric and gas facilities. Wildfire cameras give us the information we need to generate alerts in the event of a fire and to direct employees to seek safety, suspend or reduce services that may be hazardous if damaged (such as lowering pressure in certain gas transmission pipes, or cutting power to electrical substations that may be adversely affected), and initiate emergency management and response.

Benefits of wildfire cameras include:

- Heightened awareness of lightning strikes and wildfire;
- Increased ability to take safety precautions prior to a wildfire event, leading to increased employee safety;
- Increased ability to take damage mitigation actions prior to a wildfire event, leading to increased public safety;
- Increased ability to manage crews, assets, and individual personnel through knowledge of geographic areas likely to receive the most damage prior to a wildfire event;
- Scaled wildfire response based on wildfire intelligence provided by the camera network; and
- Potential for decreased restoration times due to improved situational awareness for senior management directing crew allocation and assignments.

c) Location and Timing of Activity

The wildfire cameras installed in 2019 provide visual coverage of portions of the Tier 2 and Tier 3 HFTD areas in our service territory. On an on-going basis, we evaluate areas where camera coverage may be lacking and look for opportunities to install cameras with a maximum view shed. We aim to have roughly 90 percent coverage of our Tier 2 and 3 HFTD areas by 2022.

d) Personnel and Staffing of Work

We used an outside vendor to install the cameras.

3) Sensor IQ

TABLE 2-37
SENSOR IQ
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	Sensor IQ	$53	$0

a) Nature of Activity

In 2019, we spent $53 thousand to plan for and coordinate our pilot Sensor IQ project. Sensor IQ is a proprietary SmartMeter software that enables customizable reads and alarms to identify service transformer failures. The software provides granular load, voltage, and outage data that allows us to better pinpoint situations where there is potential for loose connections or failing equipment. We plan to deploy Sensor IQ to approximately 500,000 SmartMeters in HFTD areas in 2021.

b) Reason for Activity

This tool will improve our overall situational awareness. Current SmartMeter software provides limited data that is primarily used for billing purposes. After Sensor IQ is deployed, we will have data to inform our operations and data analytics. The data collected through Sensor IQ is also critical for a variety of other wildfire related initiatives, including the Rapid Earth Fault Current Limiter, which requires feeder phasing to determine the line-earth capacitive imbalance. Increasing the amount and type of data collected will also improve our wires down algorithms to find faults.

c) Location and Timing of Activity

In 2019, our Sensor IQ work consisted of planning and coordination for future deployment. In 2021, we will deploy to approximately 500,000 residential SmartMeters in Tier 2 and

Tier 3 HFTD areas covering approximately 25,597 distribution line miles.

d) Personnel and Staffing of Work

PG&E employees in Project Management, IT, and SmartMeter Operations performed the initial project planning and coordination work in 2019. These teams will continue the process going forward, with the additions of our Distribution Grid Operations and Data Analytics, and technical support from an external vendor on the implementation and configuration of the software.

c. Advanced Fire Modeling and Wind Loading

This category of work embraces two types of activities, shown in the table below: (1) Advanced Fire Modeling; and (2) Wind Loading.

TABLE 2-38
ADVANCED FIRE MONITORING AND WIND LOADING
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	Advanced Fire Modeling	$3,941	$198
2	Wind Loading	228	3,630
3	Total	$4,169	$3,848

Each activity is discussed in more detail below.

1) Advanced Fire Modeling

Our 2019 costs for the Advanced Fire Modeling are shown in the table below.

TABLE 2-39
ADVANCED FIRE MODELING
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	Advanced Fire Modeling	$3,941	$198
2	Total	$3,941	$198

a) Nature of Activity

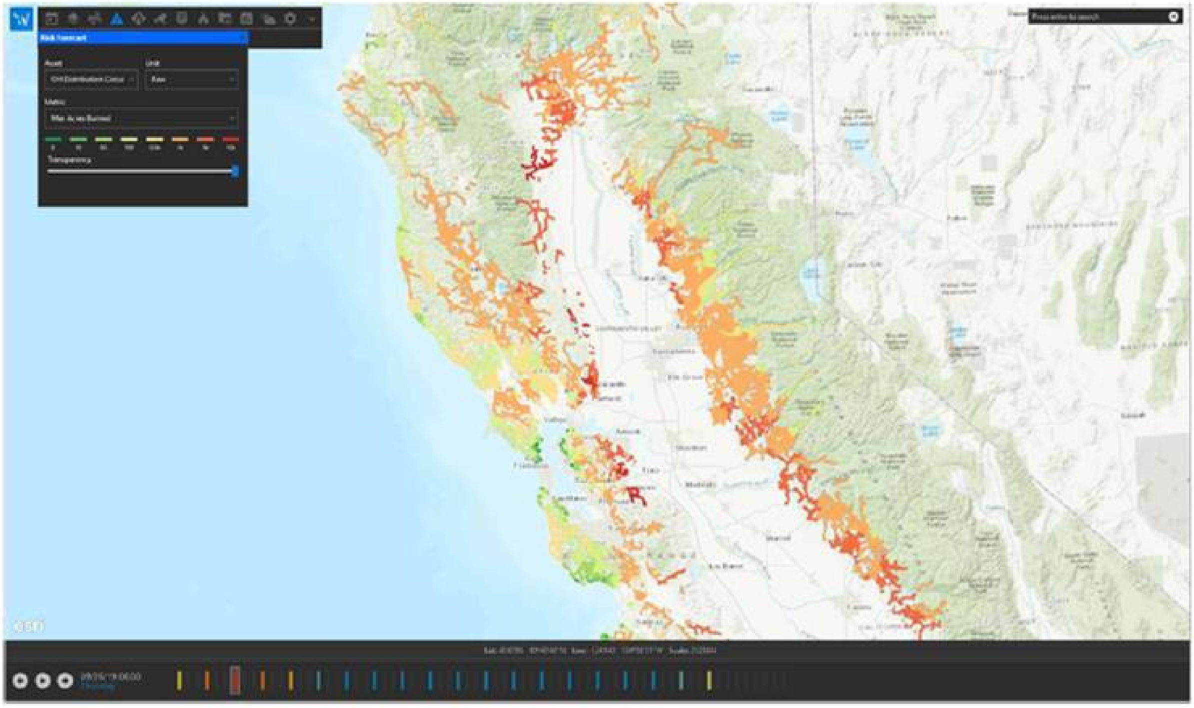
We spent $4.1 million on Advanced Fire Modeling in 2019. We partnered with an external contractor to develop and deploy advanced fire spread modeling technology that produces hourly fire spread risk scores for circuits in HFTD areas. After testing in 2019 and working with the vendor to make any necessary enhancements thereafter, we plan to operationalize this capability in 2020.

Two components of the fire spread technology were deployed for operational testing in 2019: FireCast and FireSim. FireCast runs more than 70 million fire spread simulations per day for all PG&E overhead lines in and adjacent to HFTD areas. The simulations are based on high resolution weather and fuel forecasts out 60 hours. The primary purpose of this fire spread modeling is to understand the fire spread risk profile in our service territory, as well as the highest risk circuits and zones for asset-related fires of high consequence.

The FireSim component allows fire simulations to be completed "on-demand" for emerging fire incidents or individual "what-if" analyses from any ignition source within our service territory. We can model hypothetical fire spread under different scenarios and timeframes, or model the spread of an active fire that has been detected through cameras, satellite-based fire detection, or reports from agencies.

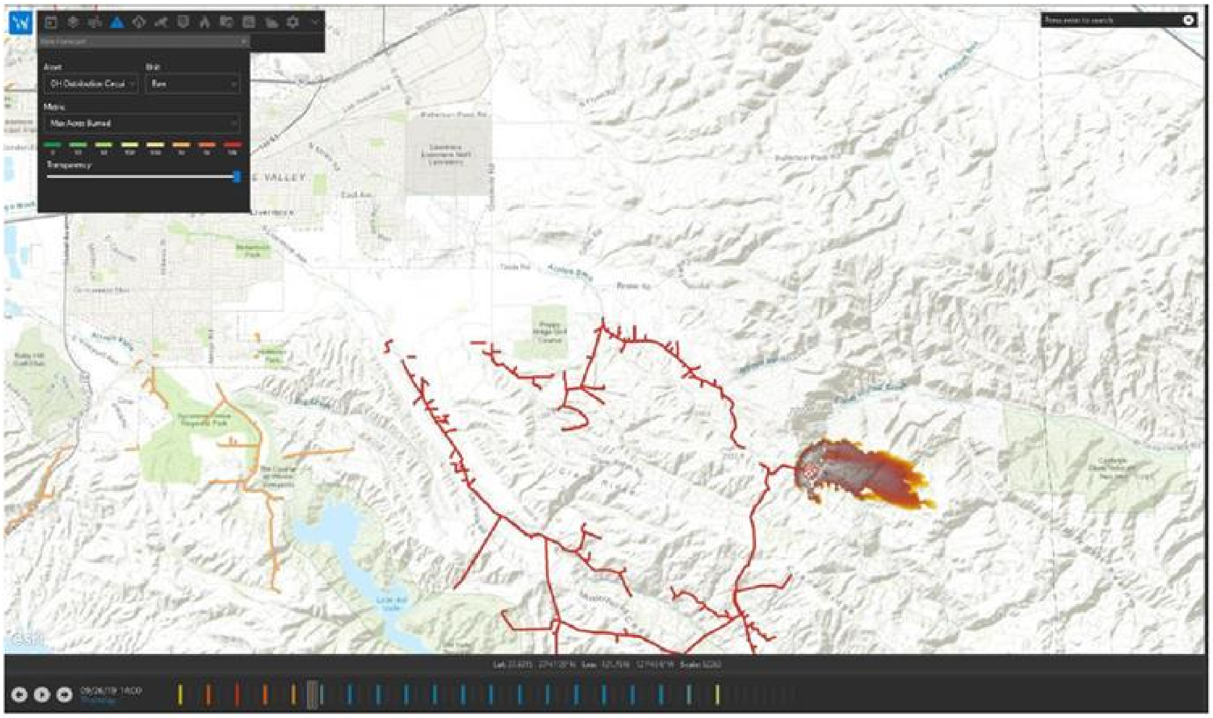
In Figures 2-26 and 2-27 below, we provide example outputs from our Firecast application.

FIGURE 2-26
EXAMPLE OUTPUT FROM FIRECAST APPLICATION



Note: Color coding represents the maximum fire size simulated from each overhead circuit.

FIGURE 2-27
EXAMPLE OUTPUT FROM FIRECAST APPLICATION



For predictive, or hypothetical, modeling, the key factor is the potential for a high consequence fire generated from any ignition point along transmission and distribution lines in HFTD areas. We will use asset-based fire spread risk to maintain situational awareness and as an additional factor informing PSPS de-energization. For active fires, the system will be run in real-time to understand the predicted spread, which will inform public and employee safety, along with emergency management and response efforts.

We use a Fire Potential Index (FPI) that combines the fire spread risk score with existing systems for tracking and scaling the overall fire danger. The Advanced Fire Modeling improvements feed into our FPI model, which was developed in 2019 by data scientists for day-to-day fire mitigation decision-making and to support PSPS assessments. A key enhancement in 2019 was updating the FPI using robust historical datasets of weather and fuel moistures as well as fire occurrence datasets. We tested dozens of input parameters and used data science best practices to determine those parameters that have the best predictive skill and their associated weighting. Using data from the USFS' Fire Program Analysis-Fire-Occurrence Database, we tagged each fire incident in the dataset in space and time to datasets of weather, fire-weather indices, fuel moisture, National Fire Danger Rating System (NFDRS) indices, and "containment" features from the climatology, and linked to the nearest model grid cell (location) for the fire ignition point. We constructed three fire-weather indices to test the optimum fire-weather index to use in the model (The FFWI, the Hot-Dry-Windy Index, and the weather component of the Santa Ana Wind Threat Index), and built over 4,000 FPI model variants based on random feature selection and subject-matter expertise.

Each day, our FPI generates fire danger ratings for each Fire Index Area, projecting as far as three days out. This rating can result in PG&E crews in a HFTD area taking additional precautions under certain conditions. For example, grinding and welding are prohibited during established FPI conditions. The FPI is combined in space and time using our high resolution modeling framework together with our Outage Producing Wind (OPW) model. The OPW model uses wind speed from our POMMS model to generate the location-specific potential for a power outage to better understand the wind-related outage risk. These modeling tools bring objectivity to our decision-making. As one example, a high fire potential combined with a high potential for outages in space and time (which can create sparks) is a key factor in a PSPS assessment.

In order to enhance this model framework, we have improved several of the input data sources and have worked with industry experts to enhance modeling capabilities and fire consequence outputs and metrics. For example, a key input into the FPI and fire spread simulations is an evaluation of the

Dead Fuel Moisture (DFM) and Live Fuel Moisture (LFM). We partnered with an external vendor to develop our DFM and LFM models using historical weather and fuel moisture measurements.

Specific enhancements to the modeling framework and resulting benefits include:

- The ability to produce territory-wide fire risk scores based on tens of millions of fire spread simulations per day;
- Enhancement of the underlying fuel model to more accurately describe the amount, quantity, and arrangement of vegetation and the type of vegetation available for combustion;
- Improvement of the fidelity and granularity of the high-resolution weather inputs to 2 km;
- Development of probabilistic fire spread results based on stochastic modeling techniques;
- The evaluation of remote sensing technologies to improve LFM model inputs; and
- The integration of other data sources, including satellite-based fire detections.

We also improved the following systems to support Advanced Fire Modeling:

- Developed an Enhanced Vegetation Index system to track “green-up” and to evaluate its effectiveness in an FPI model for our territory;
- Completed a 30-year re-analysis of wind and fire danger conditions to allow for an understanding of the frequency and duration of extreme fire weather events;
- Engaged and benchmarked with the fire science community to ensure the latest developments in technology and fire danger modeling are applied at PG&E; and
- Began development of the next generation weather model that will be deployed on the AWS cloud.

We are 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 into historical perspective.

Other expense costs incurred in 2019 include HPC core rental costs, system integration with PG&E IT, and AWS postprocessing environment Database/Application costs.

b) Reason for Activity

Advanced Fire Modeling will allow us to plan more proactively for potential wildfire scenarios and to respond more intelligently to wildfires if they occur. This mitigation is foundational—while it will not directly reduce the frequency of ignitions, it will support other response-related mitigations, such as Wildfire and Infrastructure Protection Teams and Aviation Resources.

Advanced Fire Modeling also supports key components of our Community Wildfire Safety Program, including:

- Real-time monitoring of fire danger conditions from our Wildfire Safety Operations Center;
- Daily recloser disabling operations when fire danger is very high or extreme;
- Curtailment of field activities in very high and extreme fire danger conditions as outlined in utility standard, TD-1464S; and
- Public Power Safety Shutoff assessments.

Our Advanced Fire Modeling application (Firecast) was chosen and implemented after benchmarking with SDG&E.

c) Location and Timing of Activity

This subsection describes modeling work that does not entail the deployment of resources in the field.

d) Personnel and Staffing of Work

There was no comprehensive pre-existing commercially available Advanced Fire Modeling technology when we set out to adopt one. Commercially available components existed, but building a comprehensive solution required an amalgam of technologies from high resolution weather modeling, DFM and LFM modeling, and fire spread modeling. Therefore, we developed our Advanced Fire Modeling technology using in-house resources and external vendors. Our Meteorology group oversaw the development of our Advanced Fire Modeling technology in partnership with our vendors.

2) Wind Loading

TABLE 2-40
WIND LOADING
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	Wind Loading	$228	$3,630

a) Nature of Activity

We spent $3.9 million on this area of work in 2019. Per CPUC mandate, a pole loading calculation is required every time we install a new pole and/or change the physical load on an existing pole. Our wind loading work measures the risk of structures failure under various wind conditions (e.g., speed, direction, elevation) and due to other factors affecting structure reliability (e.g., snow loading, temperature, construction grade). Our work uses emerging, i.e., pre-commercial, technology to incorporate assets attached to a structure, such as cross arms or guy stubs, and other poles connected to the structure by power lines or third-party lines (e.g., communications lines).

Unlike earlier wind loading software, which could only model single structures, the software in development in 2019 can model up to several hundred connected structures. Available information about the structure(s) is incorporated into the modeling, such as LiDAR surveys, structure materials, and latest on-site measure of pole health. Incorporating this information improves the accuracy of our central repository of structure data, the Geographic Information System (GIS).

The wind loading modeling work falls into two major categories: (1) identifying risk levels for existing structures to help prioritize preventive maintenance and replacement activities; and (2) modeling proposed new structures to ensure that the designs comply with PG&E and CPUC safety requirements before the designs go to construction.

Once developed, this technology will provide insight into failure modes, contribute to a common repository of data, and improve workflows of key asset systems to align with new data use and management strategies. Wind loading segmentation will be performed to identify the wind loading impact of each asset on a support structure, as well as on groups of structures representing a line segment. Resulting data will be integrated into appropriate systems, including our SAP Work Management application, the GIS, a new Pole Loading Database, and the Wildfire Impact Distribution Risk Model.[41]

b) Reason for Activity

The CPUC requires a pole loading calculation every time a utility installs a new pole and/or changes the physical load on an existing pole. The CPUC further mandates that relevant pole loading records be accessible for auditing. We install or change the load on roughly 20,000 poles each year. Our wind loading solution will implement several technologies and process enhancements to help improve data quality and set up processes to improve the quality of data over time.

Once deployed, benefits of the wind loading solution will include:

- Compliance with the requirements of CPUC General Order 95, Section IV, Paragraph 44.1, which states that

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41 The Transmission Support Structures IT initiative discussed in chapter 6 is a distinct but complementary effort to the wind loading software.

"The entity responsible for performing the loading calculation(s) for an installation or reconstruction shall maintain records of these calculations for the service life of the pole or other structure for which the a loading calculation was made and shall provide such information to authorized joint use occupants and the Commission upon request";

- Ability to calculate safety factors for transmission structures, document the safety factors, and chart them over time;
- Ability to maintain a consolidated history of all structure data available through a single interface, including data on historical structures at a given functional location;
- Ability to provide models of structures or structure components that can be used for a "quick start" for structure design and estimating, which reduces the effort required and the risk of errors being introduced;
- Updated critical structure details viewable through our Geographic Information System, which saves time and avoids errors by reducing manual re-entry of information; and
- Ability to provide a "closed loop" among the transmission structure design and estimating tools, the Geographic Information System, and SAP to ensure consistent, current information in the major systems of record.

c) Location and Timing of Activity

The enhanced wind loading project began in May 2019 and was managed by a central team in the San Francisco Bay Area in coordination with:

- Subject matter experts from PG&E Distribution estimators, who perform modeling work on proposed structures;
- The Desk Top Review team, who evaluate existing poles;
- The external vendor for core software development;

- Providers of data to be used by the software, such as Vegetation Management for LiDAR data, and FA&A for elevation data; and
- Other internal application teams, such as SAP and GIS.

d) Personnel and Staffing of Work

12 PG&E employees from Electric Operations and IT partnered with a third-party software provider on this project in 2019.

d. Wildfire Safety Operations Center

Our 2019 costs for the Wildfire Safety Operations Center are shown in the table below.

TABLE 2-41
WILDFIRE SAFETY OPERATIONS CENTER
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	WSOC	$4,708	$2,290

1) Nature of Activity

In 2019, we spent $7 million to relocate and operate our Wildfire Safety Operations Center (WSOC). The WSOC is a physical facility that serves as the central wildfire-related information hub for PG&E. The WSOC monitors, assesses, and directs specific wildfire prevention and response efforts throughout our service area. The WSOC interfaces and collaborates with all PG&E lines of business and develops processes and procedures directly related to wildfire prevention, response, and recovery.

The WSOC monitors for fire ignitions across our service area in real time, leveraging PG&E weather information, wildfire camera data, and publicly available information such as CAL FIRE maps, CalTrans roadmaps, NOAA's Satellite Fire Monitoring images, and social media applications, as well as first responder and local and state data. Information also comes into the WSOC from PG&E field personnel, including Public Safety Specialists and Safety and Infrastructure Protection (SIPT) crews. With input from Meteorology, the WSOC makes decisions related to resourcing and location of Field Observers. In our Emergency Operations Center (EOC), the WSOC Lead and Specialist review incoming documentation and determine if conditions warrant additional field observation or immediate consideration of PSPS.

In 2019, the WSOC deployed an industry-leading satellite fire detection system developed by our Meteorology and Fire Science team. The system uses remote sensing data from five geostationary and polar orbiting satellites to detect fires. When a fire threat is detected in one of the communities within our service area, the WSOC coordinates and mobilizes response efforts with appropriate PG&E field personnel, first responders, media, local government, and other safety officials. The WSOC coordinates with our Public Safety Specialists team, who investigate the fire threat and interface with CAL FIRE, federal fire agencies, and other agency having jurisdiction (AHJ) incident commanders to oversee the organizational response. If resources are needed to mitigate an emergency, the WSOC can activate our emergency response infrastructure.

The WSOC has also established notification protocols for communicating fire threat information to the various operations centers within the organization. Based on meeting established thresholds (e.g., fire proximity to our assets) the WSOC creates and distributes incident report updates via email with information about the wildfire status, PG&E assets threatened or involved, current red flag status, and fire weather information. The WSOC sends the updates to an internal distribution list including field staff, control center personnel, executive staff, supporting lines of business, and other PG&E emergency responders.

Going forward, the WSOC has the potential to be an all-hazard response center that is prepared to respond to any anomalies in our service territory to help our first responders quickly mitigate any service disruptions.

2) Reason for Activity

As described in the Introduction to this chapter, SB 901 required each publicly-owned California utility to submit an annual WMP to establish the utility's approach to mitigating wildfire risk caused by its electric equipment. The WSOC plays a key role in effectuating our 2019 WMP and promoting community safety by streamlining and centralizing wildfire controls and mitigations. The real-time risk information communicated to internal control centers enables us to act swiftly to protect life and property from fires threatening our assets. These notifications also facilitate sharing of critical incident information in order for us to effectively respond to fire threats in coordination with other lines of business and external emergency response agencies.

3) Location and Timing of Activity

The WSOC was initially established in 2018 and was remodeled in 2019 at its primary location in the General Office in San Francisco. During the remodel, the WSOC temporarily relocated to an alternate location in the San Ramon Valley Conference Center. In 2019, WSOC staff monitored fire threats throughout our service territory.

4) Personnel and Staffing of Work

The WSOC operates on a 24-hour basis and is staffed with experienced personnel knowledgeable in electric operations, safety, meteorology, fire science, and other areas. In 2019, the WSOC staff included 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. 13 personnel were added to the WSOC in 2019, including five Public Safety Specialists.

e. Safety and Infrastructure Protection Teams and SmartMeter Partial Voltage Detection

This category of work embraces two types of activities, shown in the table below: (1) Safety and Infrastructure Protection Teams; and (2) SmartMeter Partial Voltage Detection.

TABLE 2-42
SIPT AND PARTIAL VOLTAGE DETECTION
(THOUSANDS OF DOLLARS)[42]

Line No.	Activity	Expense	Capital
1	Safety and Infrastructure Protection Teams	–	$642
2	SmartMeter Partial Voltage Detection	0	376
3	Total	$0	$1,018

Each activity is discussed in more detail below.

1) Safety and Infrastructure Protection Teams

Our 2019 costs for the Safety and Infrastructure Protection Teams are shown in the table below.

TABLE 2-43
SAFETY AND INFRASTRUCTURE PROTECTION TEAMS
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	Safety and Infrastructure Protection Teams	–	$642

a) Nature of Activity

We spent $642 thousand to support the Safety and Infrastructure Protection Teams (SIPT) in 2019, primarily by providing them with communication equipment. SIPT crews perform high priority fire mitigation work, protect our assets, and gather critical data to help us prepare for and manage wildfire risk.

42 SIPT expense costs for 2019 are addressed in Chapter 3.

SIPT crews perform both routine and emergency work. SIPT's routine work includes:

- Fuel hazard reduction at worksites to reduce fire risk;
- Application of fire retardant to minimize ignition potential;
- Defensible space inspections;
- Fuel hazard assessment at our facilities;
- Safety protection standby (during "hot work") at our work sites;
- Medical response standby at our work sites;
- Safety patrols on our properties;
- Asset protection planning for our construction projects;
- Minor flagging support; and
- Labor support.

SIPT's emergency work includes:

- Asset protection through the application of fire retardant during wildfires, as authorized by the Agency Having Jurisdiction (AHJ);
- Fire protection at PG&E-owned facilities during wildfires, as authorized by the AHJ;
- Mop up of fire damaged PG&E assets, as authorized by the AHJ; and
- Accompanying vegetation management crews during wildfire recovery to suppress incidental ignitions.

While these teams do not respond to wildfires without agency approval, they can help suppress any potential ignition at the work site when protecting our crews and assets. When first responders arrive on scene, crews follow the Incident Command System established by the responding agency.

When we activate for a PSPS event, we deploy the SIPT crews to collect real-time weather and localized LFM data to report to the WSOC. This data is used to inform our Meteorology team's FPI model to calculate the "Probability of Ignition" based on existing firefighting standards. The potential for R5-Plus conditions, for example, can indicate a need to trigger a PSPS sooner than expected. Following a PSPS event, SIPT crews provide information to support "all clear" conditions necessary to authorize restoration activities, and they patrol sections of re-energized lines.

As part of the SIPT program in 2019, PG&E employees:

- Developed a custom SIPT engine design based on existing PG&E fleet vehicles;
- Designed custom built pumps capable of applying fire retardant;
- Acquired and outfitted temporary engines;
- Specified and acquired firefighting tools, radios, and personal protective equipment;
- Supported development of 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 Emergency Medical Technician (EMT) certification;
- Established routine and emergency operational procedures; and
- Implemented a comprehensive change management program to integrate SIPT crews with our field operations.

b) Reason for Activity

PG&E elected to establish in-house fire protection services in response to SB 901, which provides 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.

The work performed by SIPT crews reduces the consequences of wildfire ignitions in our service territory and ensures the safety of our crews working in high fire danger areas.

c) Location and Timing of Activity

In 2019, SIPT crews performed routine and emergency work throughout our service territory, with a primary focus on Tier 2 and 3 areas. During PSPS events, SIPT crews were sent to specific locations for weather data collection purposes within the Fire Index Area impacted by the PSPS.

d) Personnel and Staffing of Work

SIPT crews consist of a minimum of two PG&E employees, including a Crew Lead with a minimum of three years of experience as a Fire Captain. All team members have basic fire safety training and EMT certification, among other qualifications. As of May 2019, we employed 69 personnel in the SIPT program.

During normal work hours (i.e., Monday through Friday day shift) in 2019, SIPT crews were available to respond to emergency situations like active wildfires in lieu of their planned assignments. Outside of those hours, a specified number of SIPT crews, compensated with standby pay, remained on-call across the service territory. When fire risk was elevated, the WSOC identified additional standby personnel to support ready response. Regularly-scheduled crews were also available as necessary to assist with emergency response outside of normal work hours.

During the period of higher fire risk in 2019, PG&E used approximately 25 SIPT crews alongside its utility crews.

2) SmartMeter Partial Voltage Detection

Our 2019 costs for the SmartMeter Partial Voltage Detection are shown in the table below.

TABLE 2-44
SMARTMETER PARTIAL VOLTAGE DETECTION
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	SmartMeter Partial Voltage Detection	$0	$376

a) Nature of Activity

As a key component of our 2019 WMP, we have taken a more proactive approach to detecting wires down. In 2019, we spent $376 thousand to develop and implement across 80 percent of our circuits a proprietary SmartMeter Partial Voltage Detection system that detects wires down utilizing notifications from SmartMeters.

We contracted our SmartMeters vendor to implement special functionality into the SmartMeters firmware that detects partial voltage conditions indicative of a wire down. Under partial voltage conditions on Three-Wire distribution systems, i.e., 25-75 percent of nominal voltage, our SmartMeters send real-time alarms to the Distribution Control Center. The partial voltage condition indicates that one phase feeding the transformer has low voltage or no voltage. Energized or de-energized wires down create a low voltage condition on transformers through the mechanism of transformer back feed from the inactive phase to the fault. Prior to implementation, SmartMeters on Three-Wire distribution systems could only provide real-time alarms for the outage state.

Our 2019 costs associated with SmartMeter Partial Voltage Detection consisted of software licensing costs and vendor development, IT testing and integration, and operations and maintenance.

b) Reason for Activity

Prior to implementing this technology, we relied on reports from customers, public safety officers, and utility restoration personnel to identify downed wires on the distribution system.

We can now detect and locate downed distribution lines within minutes. Quicker response time not only reduces the amount of time a line is down but enables first responders to extinguish any wire-down related ignitions sooner.

Benefits of this project include:

- Alerts and locational information for wire down and open phase conditions;
- Increased situational awareness of potential wire down conditions for the Distribution Control Center and the Wildfire Safety Operations Center;
- Improved decision-making in responding to situations posing wildfire and safety risks;
- Reduced response time; and
- More efficient deployment of field resources.

c) Location and Timing of Activity

In 2019, we deployed partial voltage detection capability to approximately 4.5 million single phase SmartMeters across our service territory, which included meters in 25,597-line miles of Tier 2 and Tier 3 HFTD areas. In 2020, we will extend the partial voltage detection enhancement to 3-phase meters across our service territory, which includes meters in the same 25,597-line miles of Tier 2 and Tier 3 HFTD areas.

d) Personnel and Staffing of Work

We contracted our SmartMeters vendor to implement this special functionality into the SmartMeters firmware. Our employees worked on deployment and integrating the technology into the Distribution Control Center.

5. Public Safety Power Shutoffs

This area of work embraces two categories of activities related to PSPS: PSPS Events and PSPS Program Costs, as shown in the table below.

TABLE 2-45
PUBLIC SAFETY POWER SHUTOFFS
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	PSPS Events	$178,276	$1,732
2	PSPS Program Costs	34,201	–
3	Total	$212,477	$1,732

PSPS Events are characterized as the activities directly associated with proactively de-energizing our electric transmission or distribution lines following a determination of weather related imminent threats to power line assets and increased risk of catastrophic wildfire. This includes the sequence of activities beginning with EOC activation and ending with line re-energization. PSPS Program Costs include all activities supporting, but not directly connected to, PSPS events.

a. PSPS Events

Our 2019 costs for Public Safety Power Shutoff events are shown in the table below.

TABLE 2-46
PUBLIC SAFETY POWER SHUTOFF EVENTS
(THOUSANDS OF DOLLARS)

Line No	Activity	Expense	Capital
1	PSPS Events	$178,276	$1,732

1) Nature of Activity

In 2019, we spent $180 million to implement PSPS events. Our PSPS program evaluates whether to proactively de-energize a portion of our electric system in the interest of public safety as a measure of last resort to prevent an ignition during high wind weather patterns. De-energization may be necessary when a combination of winds and location-specific factors, such as vegetation dryness, are forecast to present a statistically high likelihood of damage or disruption to our above-ground power lines, suggesting a heightened risk of catastrophic wildfire.

The PSPS program encompasses all electric lines that pass through HFTD areas, including both distribution and transmission lines. The most common electric lines to be considered for de-energization are those that pass through designated Tier 2 or Tier 3 HFTD areas. Often, lines that traverse Tier 2 or Tier 3 areas also feed customers in non-Tier 2 or Tier 3 areas, meaning customers could be impacted by the risk associated with lines many miles away. While customers in HFTD areas are more likely to be affected by a PSPS event, any of our more than five million electric customers could have their power shut off if their community relies upon a line that passes through a HFTD area.

As described in our testimony served in the Order Instituting Rulemaking (OIR) to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions (PSPS OIR, or R.18-12-005), the wildfire risk in Northern California has changed dramatically in the past several years.[43] As of 2012, only 15 percent of our service area was designated as having an elevated wildfire risk on the fire-threat maps recognized by the CPUC at that time. Today, more than 50 percent of our service territory is in designated Tier 2 or Tier 3 fire-threat areas according to the CPUC's designated HFTD Map.[44]

Our ability to predict the scope and duration of a PSPS event is limited to near-term forecasts of weather and vegetation fire potential. The models used to forecast outage producing winds and fire potential calculate near term forecasts four times daily. Results from these models, in conjunction with global and local forecasts from external agencies, are evaluated by members of our Fire Science and Meteorology team to determine if there is concurrence of a heightened outage risk from a wind event and the potential for large wildfires to occur. If severe weather conditions exist, we determine the potential scope of a PSPS event by identifying which,

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43 PSPS OIR, PG&E's February 5, 2020 Testimony, R.18-12-005.

44 *Id.*, Chapter 1, p. 1-2, Line 22-26, citing to HFTD area maps designated in D.17-12-024, *available* at https://www.cpuc.ca.gov/FireThreatMaps/.

if any, distribution and transmission facilities are within the area forecast to be impacted by the weather event and would require de-energization in order to protect public safety. Our Meteorology team closely monitors changing forecasts and conditions, updating the PSPS Incident Command team of any changes in the forecasts or conditions and continually revising the scope of the possible event, both in terms of event magnitude and estimated timing, to reflect the latest forecast conditions. The ongoing forecast updates may add to or remove additional areas from the scope of the PSPS event.

One of the key components of our PSPS response plan for the 2019 wildfire season was—and remains—the EOC. The EOC is tasked with executing PSPS events in compliance with Phase One and Phase Two Guidelines[45] and in a manner that minimizes disruptions to our customers.

We have a clearly delineated process for determining whether to activate the EOC and what to do once the EOC is activated for a PSPS event. Those steps are: (1) weather monitoring before the EOC is activated; (2) activation of the EOC; (3) identifying and approving the initial scope of the de-energization event along with notifications to Public Safety Partners and customers impacted by that scope; (4) deciding whether to de-energize based on updated forecast and situational intelligence information; (5) sending final warning notifications to impacted Public Safety Partners and customers; (6) de-energizing transmission and distribution assets identified to be in scope; and (7) making the weather all-clear determination and re-energizing the power grid.

a) Community Resource Centers (CRC)

During a PSPS event, i.e., from the time electric service is shut off until it is restored, we open Community Resource

[45] Decision Adopting De-energization Guidelines, D.19-05-042 and D.20-05-051under OIR R.18-12-005.

Centers to provide a safe, energized space for impacted customers and residents experiencing a PSPS-related outage.

In 2019, we opened and operated CRCs in counties effected by a PSPS event and/or funded local agencies to stand up and operate similar resource centers for their communities. We used the following three CRC designs: (1) mobile Customer Support Units, which are large vans deployed locally for regions expecting lower turnout; (2) outdoor, tented locations; and (3) indoor locations.

At these CRCs, we provided visitors with PSPS event information, water and restrooms, tables and chairs, power strips to meet basic charging needs including for cell phones, laptops, and small medical devices, and Wi-Fi and cellular service access where possible. For certain events, we provided additional supplies such as ice, blankets, snacks, flashlights, and small electronic device chargers, as well as N95 face masks in regions near active fires.

We designed the CRCs to meet the following criteria: Americans with Disabilities Act and environmentally compliant; capable of accommodating up to approximately 50-100 customers at a time (with the exception of the mobile Customer Support Units); approved by the site owner; Wi-Fi and cellular service accessible; adequate spacing for outdoor locations. The CRCs were typically open from 8:00 a.m. to 8:00 p.m. In compliance with Commission Resolution ESRB-8 and D.19-05-042 OP 1, we submitted PSPS event reports for each 2019 PSPS event. These reports included detailed descriptions of our CRC approach including, but not limited to, the total number of CRCs, the location, type, and timeline of each CRC, local government coordination on site selection and closure, and customer visitation information.[46]

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46 We include CRC-related reports in Section 13 and Appendix F of each PSPS event report.

We understand that PSPS events cause significant and serious disruptions to the customers and communities we serve, and we aim to reduce the size and duration of these events. As described in various sections of this chapter, we will mitigate PSPS impacts to our customers in 2020 and beyond by using advanced meteorology models to forecast wildfire risk conditions more granularly, applying improved analyses to determine which parts of our system face high fire risk, and improving switching and sectionalization such that PSPS events affect smaller portions of the grid. We believe these measures can reduce by one-third the number of customers affected by future PSPS events.[47] We have adopted a new goal of conducting inspections of the electric system and restoring service to 98 percent of PSPS-affected customers within 12 daylight hours of the "weather all-clear" declaration. We are also working to improve our coordination with state, local, and community agencies, and to provide extensive information and support to customers before, during, and after PSPS events.

2) Reason for Activity

The Commission has affirmed that regulated utilities should implement PSPS events when—and only when—necessary to prevent catastrophic wildfires. The Commission has ordered that, pursuant to Sections 451 and 399.2(a) of the Public Utilities Code, the "statutory obligation to operate [a utility's] system safely requires [the utility] to shut off its system if doing so is necessary to protect public safety.[48] That is, when utilities "reasonably believe that there is an imminent and significant risk that strong winds will topple its power lines onto tinder dry vegetation or will cause major vegetation-related impacts on its facilities during periods of extreme

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47 This forecast assumes that the same weather patterns leading to the largest 2019 PSPS events are replicated in future years.

48 Decision Granting Petition to Modify D.09-09-030 and Adopting Fire Safety Requirements for SDG&E, D.12-04-024, at p. 25 (Apr. 26, 2012) (exploring statutory authority to de-energize).

fire hazard," they may exercise their statutory authority to de-energize.[49]

3) Location and Timing of Activity

We conducted nine PSPS events in 2019, with the largest event impacting 968,000 customers in 37 counties. The 2019 PSPS Events occurred on June 8-9, September 23-24, September 25-26, October 5-6, October 9-12, October 23-25, October 26-29, October 29-November 1, and November 20-21.

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49 Electric Safety and Reliability Branch Resolution 8 (July 12, 2018) (ESRB-8), p. 4 (emphasis removed).

TABLE 2-47
PSPS EVENT KEY DATA

	Event	Jun 8-9	Sep 23-26	Oct 5-6	Oct 9-12	Oct 23-25	Oct 26-Nov 1	Nov 20-21	Total
Event	Event Days	2	4	2	4	3	7	2	24
	Cost per Event	$ 6,813	$ 5,339	$ 1,711	$ 38,674	$ 30,885	$ 78,793	$ 16,536	$ 178,751
	Max Wind Gust	63 mph	58 mph	51 mph	77 mph	80 mph	102 mph	75 mph	
	Damages/Hazards	5	4	2	116	26	554	15	722
	First out-to-last restored Duration	35 hrs	65 hrs	17 hrs	89 hrs	52 hrs	151 hrs	39 hrs	
	Counties Impacted	6	7	3	35	17	37	11	
	Avg. Restore Dur. (CAIDI from all clear)	5 hrs	7 hrs	4 hrs	25 hrs	5 hrs	22 hrs	10 hrs	
	Avg. Outage Duration (CAIDI)	16 hrs	16 hrs	14 hrs	38 hrs	25 hrs	56 hrs	25 hrs	
Customer	Customers Impacted	22,474	49,113	11,609	735,440	178,809	967,754	49,203	2,014,402
	MBL Door Knocks	599	1,396	180	5,080	881	4,158	674	12,968
	CRCs Open	4	9	3	33	28	77	34	188
Operations	Distribution Circuits	22	61	17	442	146	1,021	57	1,766
	Distribution Miles (Tier 1)	-	670	70	7,290	903	11,508	634	21,075
	Distribution Miles (Tier 2/3)	-	3,433	812	16,087	7,239	33,797	2,918	64,286
	Distribution Miles (Total)	-	4,103	882	23,377	8,142	45,305	3,552	85,361
	Restoration Helicopters	17	16	12	44	42	46	45	

Note Distribution Miles data not available for June 8-9 event

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(a) PSPS event information can be found in the De-energization Reports, available here: https://www.pge.com/en_US/safety/emergency-preparedness/natural-disaster/wildfires/public-safety-power-shutoff-faq.page?WT.mc_id=Vanity_psps.

(b) Damages include occurrences like a tree falling on a powerline and damaging our assets. Hazards include occurrences that could have sparked an ignition if the line was left energized, like a tree limb found suspended in electrical wires. Restoration and repair costs for damages are addressed in Chapter 3.

(c) Total customers impacted does not reflect unique customers because some customers were affected by multiple events.

4) Personnel and Staffing of Work

PSPS events are supported by a combination of internal employees and contracted resources. The number of personnel required depends on the size and scope of the PSPS event. However, regardless of size, the following groups were responsible for providing support in response to the 2019 PSPS events:

- EOC Admin: The EOC is comprised of a multi-disciplinary team of PG&E employees who assume existing emergency response positions consistent with the Incident Command System. Included in an emergency response team are the EOC Commander and the Command and General Staff. Command Staff positions include the Safety Officer, Customer Strategy Officer, Liaison Officer, Human Resources Officer, Legal Officer and Public Information Officer. General Staff positions include the Operations Section Chief, Planning and Intelligence Section

Chief, Logistics Section Chief, Finance Section Chief and Intelligence & Investigations Section Chief. Each member of the Command and General Staff have specific responsibilities and staffs to help execute their responsibilities. For EOC activations specific to PSPS events, additional roles and positions are staffed including, but not limited to the Officer-in-Charge, and PSPS Technical Specialist.

- Information Technology: The EOC IT Branch coordinates the response of PG&E’s IT resources and systems in support of all stages of PSPS. This involves:
  - Providing the EOC a coordinated communication as to the readiness and any limitations of IT systems and support;
  - Ensuring availability of IT capabilities to support the PSPS event (from applications like PGE.com websites, to infrastructure and facilities), which may require cancelling planned deployment and/or field activities;
  - Determining potential needs for IT logistical support in the field (radios, base camps, etc.);
  - Managing the impact of a PSPS outage on IT resources (e.g. radio support, SCADA / network communication devices, etc.); and
  - Responding to needs of the EOC and coordinating any needed changes to IT support (Information Technology Coordination Center).
- Aviation Services: This group interfaces with the Operations Section Chief to directly manage aviation asset requests from the EOC and WSOC, and to assess the current situation to potentially provide aerial support which could involve the inspection lines. Additional responsibilities include:
  - Communicating with EOC section chiefs to receive information on current PSPS situation;
  - Determining patrol aircraft deployment plan (for example, number of patrol aircrafts needed, number and location of

aircrafts available, pilot resources available, timing of patrols);

– Determining aircraft operational times/periods based on FAA and company policy for duty days and flight hours, as well as, weather conditions, and air space operating environments;

– Approving and managing movement/re-deployment of all aviation assets through coordination of the Operations Branch Chief;

– Conducting and reporting out on aerial patrols; and

– Coordinating with Electric Operations, the EOC, and WSOC on findings.

- Customer Strategy Officer team: During PSPS events, our Public Information Officer (PIO), Liaison, and Customer Strategy Officer (CSO) teams provide the following key support to customers and partner agencies:

  – Coordinating with local, state, and/or federal agencies to provide real-time situational updates and coordinate local needs (e.g., regular operational briefing calls, PSPS portal access, GIS Analyst support, and securing approvals of CRC site locations by jurisdiction);

  – Issuing distribution and transmission-level notifications to potentially impacted customers consistent with the CPUC's recommended notification timeline, which includes direct notifications to potentially impacted customers via calls, text messaging, and e-mail;

  – Providing direct support and real-time situational intelligence to communications providers, Community Choice Aggregators (CCA), transmission-level customers and other critical customers;

  – Maintaining an online presence and update PG&E's webpage and social media channels including Facebook, Twitter, and NextDoor;

- Coordinating directly with the media, including providing press releases to multi-cultural news outlets to provide translated communications to their viewers/listeners/readers, and providing news briefings;
- Managing intake requests for backup power and customer escalations;
- Managing in-person visits to medical baseline customers who did not confirm receipt of their automated notifications; and
- Staffing Community Resource Centers (CRC).

- Electric Distribution Operations: The Electric Distribution Operations Branch coordinates with the Electric Distribution Emergency Center in connection with the de-energization, recovery, and restoration of our electric distribution system. The branch also provides information on customer outages and field operational challenges to the EOC. Electric Distribution Operations responsibilities during a PSPS event include:
  - Providing "grid awareness" when a PSPS event is forecasted, which can include any work in progress (planned and unplanned), Critical Operating Equipment, SCADA health, abnormal switching, load-at-risk, protection studies, and manual capabilities;
  - Developing and executing the resource plans for pre-PSPS assessment staging/repair work, field observations, de-energizing, patrols, and restoration;
  - Dispatching Medical Baseline door-knock resources to ensure successful notification when required; and
  - Visually inspecting thousands of miles of power lines to assess damage and the progress of repairs, and reporting patrol progress.
- Electric Transmission Operations: Electric Transmission Operations responsibilities during a PSPS event include:
  - Coordinating with the Command Staff to ensure timely and accurate communications with the California Independent

System Operator's (CAISO) on-call communications representative;

  - Aggregating risk and consequence scores for assets;
  - Defining and proposing risk and consequence targets for event;
  - Performing and supporting an array of PSPS activities such as initial transmission line scoping, Direct and Total Transmission Impact Studies, system protection studies, rotating outages management, developing de-energization and restoration strategies, wildfire assistance, communicating and coordinating with the CAISO, and ensuring that the grid is operated in a safe, reliable manner in compliance with North American Electric Reliability Corporation (NERC) standards;
  - Providing a "grid awareness" baseline when a PSPS event is forecasted, which can include work in progress, open tags, vegetation work in progress, SCADA health, abnormal switching, load at risk, and manual capabilities; and
  - Developing and executing the resource plans for pre-PSPS assessment staging/repair work, field observations, de-energizing, and patrols and restoration.
- Hydro Support: Power Generation responsibilities during a PSPS event include:
  - Providing EOC leads with a list of potentially impacted PG&E Power Generation managed facilities and business continuity plans as a result of a PSPS event; and
  - Staging and mobilizing response resources as necessary.
- Logistics: The Logistics Section secures resources, supplies, food, lodging, vehicle and equipment rentals and fuel, and maintains equipment for incident personnel. Other Logistics responsibilities during a PSPS event include:
  - Working with the Electric Operations and the Customer Care organization to determine the need for base

camps, staging areas, micro sites, and/or Community Resource Centers (CRC);

- Working with Land Acquisition to identify locations needed for base camps, staging areas, micro sites and/or CRCs and confirming their availability;
- Staffing and supporting base camps, staging areas, micro sites and/or CRCs activations;
- Securing resources for the sites described above, including supplies, food, temporary lodging, vehicle and equipment rentals, flagging support, security, and fuel; and
- Providing mobile generators when directed to and implemented following TD-2999B-046, Mobile generator use during PSPS events.

b. PSPS Program Costs

Our 2019 costs associated with preparing for Public Safety Power Shutoffs are shown in the table below.

TABLE 2-48
PUBLIC SAFETY POWER SHUTOFF PROGRAM COSTS
(THOUSANDS OF DOLLARS)

Line No.	Activity	Expense	Capital
1	PSPS Program Costs	$34,201	–

1) Nature of Activity

In 2019, we spent $34 million on activities necessary to ensure readiness for PSPS events. These efforts include our vendor costs to prepare functionality and issue customer notifications during PSPS events, as well as all work conducted prior to PSPS events in order to help educate, prepare, and support our customers and communities, and prepare our personnel through field exercises and training.

a) Customer Notifications

In 2019, we contracted with a vendor to issue PSPS event notifications to potentially-impacted customers during PSPS events.

b) Customer Preparedness Outreach

To help improve coordination and overall PSPS preparedness, we conducted extensive communications with customers and communities in 2019 and alerted 5.4 million PG&E electric customer premises of the potential for PSPS events to prepare them prior to the fire season.[50] Our community outreach included letters, emails, meetings, in-person events, listening session meetings with county and tribal officials, outreach to Public Safety Partners and large/critical customers, radio, digital, television, and print advertising, as well as social media and earned media outreach.

We briefed the CPUC, CAL FIRE, Cal OES, and other entities throughout the state on our PSPS approach and analysis, including our criteria and data analytics for PSPS events. We also shared this information broadly with the public through a series of workshops, open houses, webinars, meetings, and presentations throughout 2019. We posted criteria on our external-facing website and included it in our PSPS Policies and Procedures resource on www.pge.com/psps.

In addition to these efforts, California's large electric IOUs (PG&E, Southern California Edison and SDG&E, collectively the "joint IOUs") worked together on coordinating statewide outreach for PSPS education and awareness.

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50 The PSPS customer outreach costs described here are distinct from the similar costs described in the CWSP PMO section of this chapter and were tracked separately. The CWSP PMO performed high-level wildfire outreach that included general information about PSPS. In contrast, the outreach described in this section was primarily focused on preparing customers for PSPS events.

Our 2019 outreach efforts to help customers prepare for wildfires and PSPS events are reflected in the table below.

TABLE 2-49
PSPS AND WILDFIRE PREPARATION OUTREACH

Line No.	Customer Engagement		2019 Outreach Completed
1	Community Events	Open Houses	23
2		Customer Webinars	3
3	Earned Media	News Releases	124
4	Advertising	Advertising Impressions TV, Digital, Social, Radio, Print	~84 million Avg. impressions/month
5	Direct-to-Customer	Direct Mail Campaigns Letters, Postcards, Brochures, Bill Inserts/Packaging	17
6		Customer Email Campaigns	25
7	Digital Media	Social Media Posts	21 Facebook Posts 187 Tweets[(a)]
8		PG&E Website Alert Banner	8 million impressions
9		PG&E Website Pop up to Update Contact Information	2 million impressions
10	Direct Engagement	Meetings with business customers	All assigned business customers and critical facilities in Tier 2 & 3 HFTD areas

(a) 2019 numbers do not include PSPS event-related posts, which are described in PG&E PSPS event reports.

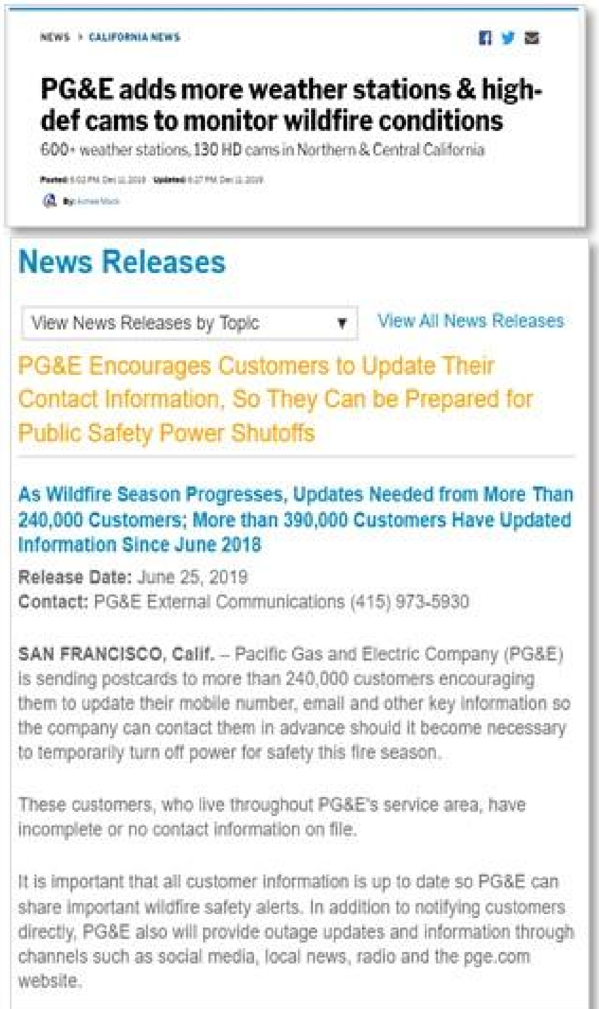
i) Community Events

In 2019, we held 23 open houses across our service territory, and three customer-specific webinars to supplement the open houses for customers and members of the public who were not able to attend an open house. Over 3,200 people attended these events.

ii) Media

In 2019, we issued 125 news releases focused on ensuring customers and communities were prepared for an emergency, including both planned and unplanned outages, and provided progress updates related to our wildfire prevention efforts. All news releases can be found at: https://www.pge.com/en/about/newsroom/newsreleases/index.page.

FIGURE 2-29
SAMPLE OF PG&E NEWS RELEASE


NEWS > CALIFORNIA NEWS

PG&E adds more weather stations & high-def cams to monitor wildfire conditions

600+ weather stations, 130 HD cams in Northern & Central California

News Releases

View News Releases by Topic

View All News Releases

PG&E Encourages Customers to Update Their Contact Information, So They Can be Prepared for Public Safety Power Shutoffs

As Wildfire Season Progresses, Updates Needed from More Than 240,000 Customers; More than 390,000 Customers Have Updated Information Since June 2018

Release Date: June 25, 2019
Contact: PG&E External Communications (415) 973-5930

SAN FRANCISCO, Calif. – Pacific Gas and Electric Company (PG&E) is sending postcards to more than 240,000 customers encouraging them to update their mobile number, email and other key information so the company can contact them in advance should it become necessary to temporarily turn off power for safety this fire season.

These customers, who live throughout PG&E's service area, have incomplete or no contact information on file.

It is important that all customer information is up to date so PG&E can share important wildfire safety alerts. In addition to notifying customers directly, PG&E also will provide outage updates and information through channels such as social media, local news, radio and the pge.com website.

iii) Social/Digital Media

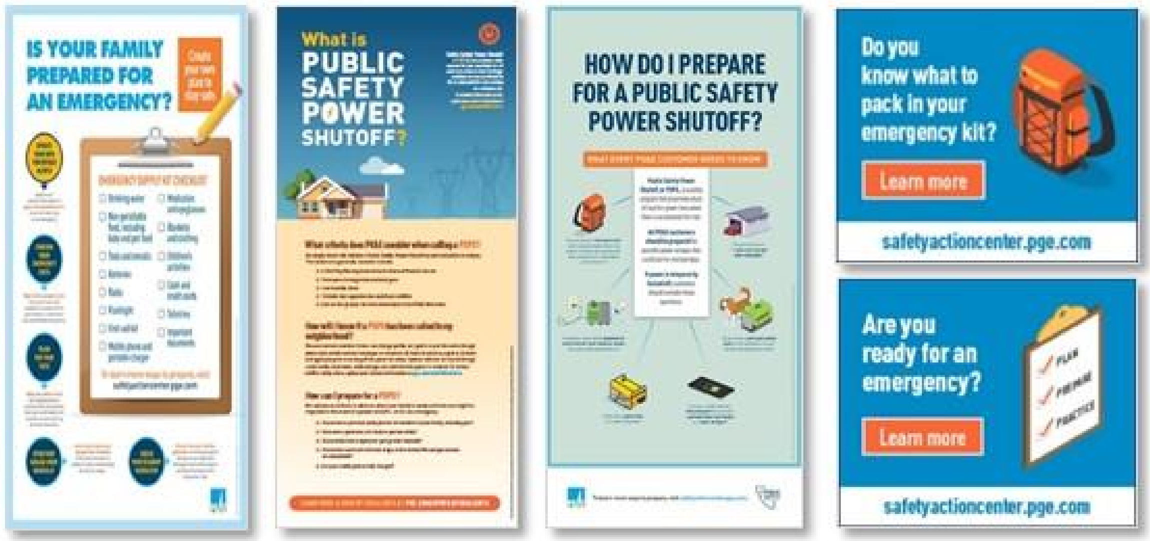
In 2019, we issued over 200 social media posts on Facebook and Twitter (not including PSPS event-related updates, which are captured in the subsection discussing PSPS Events) that provided customers with emergency preparedness information and recommended actions to prepare for planned and unplanned outages. We also used existing inbound traffic to pge.com to further increase PSPS awareness by placing an alert banner emphasizing the importance of PSPS preparation on almost every page of pge.com in the months leading up to peak fire season. We also created a pop-up that was shown to every customer who logged into their account, prompting the customer to update their contact information to ensure they received important PSPS event related notifications. These warning banners were shown more than eight million times leading up to the October 2019 PSPS events.

FIGURE 2-30
SAMPLE PG&E WEBSITE BANNER

iv) Advertising

In 2019, we conducted extensive advertising via TV, website, social media, radio, and print, resulting in an average of 84 million media impressions per month. The ads emphasized emergency preparedness (e.g., what to pack in an emergency kit, how to make an emergency plan) and directed customers to the Safety Action Center, where they could find information on preparing for PSPS events, wildfires, and other natural disasters.

FIGURE 2-31
SAMPLE PG&E EMERGENCY PREPAREDNESS ADVERTISEMENTS



v) Direct Mail and E-Mail

In 2019, we issued 25 emails and 17 different direct mail piece types, including letters, postcards, brochures, and bill inserts focused on emergency preparedness and PSPS. In total, we sent over 32 million direct mail pieces.

vi) Direct Business Customer Engagement

In 2019, we met with all assigned large commercial and industrial customers, including critical facilities served by lines that run through Tier 2 and Tier 3 HFTD areas, to share PSPS and emergency preparedness information and update customer PSPS contact information. These customers included refineries, Bay Area Rapid Transit District, the California Department of Transportation, and the California Hospital Association and its members.

c) Field Exercise/Training

In 2019, we invested resources in training our crews to quickly restore power during a PSPS event while maintaining public and employee safety. Our crews conducted 18 restoration drills in HFTD areas across northern and central California. These efforts focused on practicing the coordination of emergency response teams, inspecting lines for damage, and quickly restoring power while maintaining public and employee safety. These full-scale drills were part of our expanded Community Wildfire Safety Program, and helped our personnel and contractors prepare for the challenges they faced during actual PSPS events.

2) Reason for Activity

Protecting public safety during a PSPS event requires extensive coordination among many parties. The Commission's Phase 1 Decision emphasizes that safe and effective de-energization events are a "shared responsibility between the utilities, Public Safety Partners, and local governments" and a "joint effort."[51] This is practical because in many cases utilities would not be able to mitigate certain burdens without the help of its Public Safety Partners. The Phase 1 Decision also imposed notification requirements.

3) Location and Timing of Activity

Prior to the 2019 peak wildfire season, PG&E designed and executed a comprehensive PSPS community outreach strategy to increase awareness of PSPS and readiness for extended power outages statewide. To that end, PG&E personnel attended over 1,080 meetings across the state with cities, counties, agencies, tribes, first responders, community groups, and other stakeholders.

4) Personnel and Staffing of Work

Our employees spent approximately 80,000 hours to support these community engagement efforts in 2019. This labor consisted primarily of verifying customer contact information, training for outreach and engagement, responding to escalations as a result of

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51 D.19-05-042, at pp. 5-6. The Commission noted that multi-party coordination was particularly critical for supporting Access and Functional Needs (AFN) populations. D.19-05-042, at p. 81:

> [T]he Commission recognizes that the utilities will be unable to identify and notice all AFN populations and must rely upon local and state jurisdictions to assist in this effort. This will be an ongoing endeavor.

outreach, staffing open houses and webinars, and hosting other community engagement events.

Our employees spent approximately 2,000 hours to support Corporate Communications, and approximately 15,000 hours on PSPS field exercises in 2019.

The PSPS Operations team spent approximately 8,000 hours to support PSPS readiness in 2019. The team's responsibilities included supporting the development and implementation of various tools[52] needed to execute PSPS events, developing processes for transmission PSPS scoping in partnership with Meteorology and Asset Strategy, improving the overall PSPS event scoping process by minimizing manual process steps, ensuring timely and accurate data reporting, and otherwise managing PSPS Process Documentation.

C. Conclusion

As the risk of catastrophic wildfires in California has increased dramatically over the past few years, PG&E has transformed how we respond to that risk. Working in conjunction with many partners, we have identified and implemented measures to reduce wildfire ignitions, reduce the impacts of PSPS events, and help our communities cope with these changes and challenges. Our wildfire safety programs are rapidly evolving as we gain experience on how various measures and technologies work to reduce the threat and scope of catastrophic fires. Actions such as vegetation management, equipment repairs, and system hardening may materially reduce the risk, number, and extent of wildfires—but at the same time, factors driven by climate change, including drought and high temperatures, may increase that risk and counteract our efforts over time.

PG&E is committed to doing our part. We will continue to study and analyze the impact and cost-effectiveness of the mitigation measures we are taking, and incorporate lessons learned from 2019 into our wildfire mitigation efforts going

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52 These tools include: (1) the PSPS Viewer; (2) the PSPS Portal, an online platform for sharing key event and sensitive customer information with Public Safety Partners; (3) the PSPS Situational Awareness Tool, a central repository of event data for decision making during events; and (4) the PSPS FORCE Tool, which estimates field resources needed to patrol and restore PSPS events.

forward. We will continue to work with our customers, communities, and partners to learn how to better serve their needs and reduce the consequences of wildfires and wildfire mitigations in the future.

PACIFIC GAS AND ELECTRIC COMPANY

2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS

CHAPTER 3

ELECTRIC DISTRIBUTION: CEMA

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS
CHAPTER 3
ELECTRIC DISTRIBUTION: CEMA

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A. Introduction

This chapter describes Pacific Gas and Electric Company's (PG&E or the Company) response to the following catastrophic events:

- 2017 Tubbs Fire
- 2017 La Porte Fire
- 2017 Cherokee Fire
- 2018 Carr Fire
- 2019 January-February Storms
- 2019 October Wind Events
- 2019 Glencove Fire
- 2019 Bethel Island Fire
- 2019 Camino Fire

This chapter demonstrates the necessity and reasonableness of the steps PG&E took to: (i) repair the electric distribution facilities damaged and (ii) restore service to customers during these catastrophic events. PG&E's response to these events were coordinated and managed so that service could be restored to PG&E customers as quickly and efficiently as possible. The steps PG&E took were necessary and reasonable to eliminate potentially hazardous conditions, communicate with customers, repair or replace damaged facilities and restore vital electric service.

The remainder of this chapter is organized as follows:

- Section B provides a summary of the financial request;
- Section C explains the costs incurred by PG&E in response to these catastrophic events; and
- Section D provides a brief conclusion.

B. Summary of Request

PG&E incurred $196 million in capital expenditures and $182 million in expense for its electric distribution costs related to these catastrophic events through December 31, 2019. Of those total costs incurred, PG&E seeks recovery of only those Catastrophic Event Memorandum Account (CEMA)-eligible incremental capital and expense costs, after the adjustments that are described in Chapter 9 of this application. This chapter addresses the total spending, prior to the Chapter 9 adjustments.

Table 3-1 provides a detailed breakdown of the CEMA-eligible costs by: CEMA Event; Major Work Category (MWC) 95 (Capital); and MWC IF (Expense).

TABLE 3-1
CEMA-ELIGIBLE ELECTRIC DISTRIBUTION BREAKDOWN OF EXPENDITURES
(THOUSANDS OF DOLLARS)

Line No.	Event by Year	Capital MWC 95	Expense MWC IF	Total
1	2017 Tubbs Fire	$93,929	$64,341	$158,271
2	2017 Laporte Fire	804	61	865
3	2017 Cherokee Fire	130	90	220
4	2017 Subtotal	$94,864	$64,492	$159,356
5	2018 CARR Fire	$1,228	$491	$1,719
6	2018 Subtotal	$1,228	$491	$1,719
7	2019 January February Severe Storms	$90,418	$109,327	$199,745
8	2019 October Wind	9,263	7,893	17,156
9	2019 Glencove Fire	200	–	200
10	2019 Bethel Island Fire	24	0	24
11	2019 Camino Fire	10	–	10
12	2019 Subtotal	$99,915	$117,220	$217,135
13	Grand Total	$196,007	$182,203	$378,210

The amounts referenced above are the amounts incurred in counties in which a state of emergency was declared by a competent state or federal authority.

Occasionally, PG&E incurred costs related to these events outside of the declared counties. Table 3-2 below shows the systemwide costs incurred relating to these events, which total $436.9 million in expense and capital expenditures. PG&E is not seeking recovery through CEMA of the costs incurred outside of the declared counties.

TABLE 3-2
SYSTEMWIDE ELECTRIC DISTRIBUTION BREAKDOWN OF CEMA EVENTS
(THOUSANDS OF DOLLARS)

Line No.	Event by Year	Capital MWC 95	Expense MWC IF	Total
1	2017 Tubbs Fire	$93,929	$64,341	$158,271
2	2017 Laporte Fire	804	61	865
3	2017 Cherokee Fire	130	90	220
4	2017 Subtotal	$94,864	$64,492	$159,356
5	2018 CARR Fire	$1,228	$491	$1,719
6	2018 Subtotal	$1,228	$491	$1,719
7	2019 January February Severe Storms	$113,768	$144,691	$258,459
8	2019 October Wind	9,263	7,893	17,156
9	2019 Glencove Fire	200	–	200
10	2019 Bethel Island Fire	24	0	24
11	2019 Camino Fire	10	–	10
12	2019 Subtotal	$123,265	$152,584	$275,849
13	Grand Total	$219,356	$217,568	$436,924

Costs identified in this chapter represent electric distribution CEMA eligible costs only unless otherwise noted.

CEMA eligible costs for the Tubbs, LaPorte, and Cherokee fires are included in this application insofar as the California Department of Forestry and Fire Protection (CAL FIRE) and the Commission's Safety and Enforcement Division reports have now been issued on the origins of these fires. CEMA eligible costs for the Carr Fire presented in this application are for costs recorded after December 31, 2018 and are distinct from the CEMA eligible costs presented for the Carr Fire in Application (A.)19-09-012. The costs sought in A.19-09-012 were for costs prior to December 31, 2018.

C. Damages to PG&E's Electric Distribution Facilities and Restoration Activities

The activities described in this chapter represent PG&E's response to both storm events and wildfires.

Fires are different from winter storms in terms of their impact on assets. Winter storms cause damage to electric distribution facilities that is often widespread, involves large portions of the service territory simultaneously, and can be comparatively short in duration. A winter storm passes through the service territory, damaging facilities and sometimes causing a large volume of outages to customers. For winter storms, PG&E is the response owner and manages the pace of restoration.

In contrast, fires are concentrated in a specific geographic area and can be far more dynamic. Fires can last for an hour or weeks. Influenced by factors such as humidity, wind speed and direction, available fuel, and topography, fires can change direction or rate of spread, making them challenging to predict. Response to wildfires is led by the jurisdictional fire agency, usually CAL FIRE or the United States Forest Service. Access to infrastructure impacted by the fire is granted by the fire Incident Commander (IC). This increases the level of coordination required between PG&E and the IC and may involve an extended response based on the activity, fire ground safety and/or the level of complexity of the incident.

Damage to the electric distribution system is also different in a winter storm than in a fire. Winter storms may break poles, cross arms, spans of wire, or other facilities at intermittent locations within the impacted division, and generally involve a large, widespread volume of outage location. In contrast, a fire may destroy electric distribution facilities in its path. Depending on the geographic concentration of a fire, outage volume may be smaller than during a winter storm. In some instances, circuits can be de-energized in advance of the fire spread to protect firefighters and the public from exposure to energized distribution conductors. Restoration activities during a fire often involve replacing all of the assets and components in the fire's path, rather than portions of assets or components such as a cross arms or a broken pole. The following events are described in detail below:

1. 2017 Events

On the evening of October 8, 2017, several fires began across the Humboldt, North Valley, Sonoma, Sierra, Sacramento, Stockton, and North Bay divisions. Based on forecasted weather of gusty and dry wind, PG&E activated four regional Emergency Operations Centers on the morning and afternoon of October 8th.

The weather conditions were driven by a rare wind event that packed strong gusts of wind in excess of 75 miles per hour (mph) in some cases. The fires grew rapidly across these areas. According to the CAL FIRE, these wildfires consumed more than 245,000 acres and destroyed an estimated 8,900 structures.

PG&E experienced significant damage which resulted in impacting approximately 241,000 customers who experienced sustained outages. PG&E restored service to 99.9 percent of service-ready electric customers within 13 days and the remaining few by November 7, 2017.

For its restoration efforts, PG&E established four base camps, two micro sites, one staging area and two laydown areas, covering more than 200 acres. PG&E's response to the fires required the support of more than 5,261 resources:

- 3,634 employees
- 940 contractors
- 256 mutual assistance personnel
- 431 shared resources (IT support, etc.)

PG&E coordinated with CAL FIRE to allow access to fire areas in order to perform assessments, pre-treat utility infrastructure with fire retardant, perform aggressive vegetation removal, and begin restoration activities during the fire containment.

The following three fires—Tubbs, La Porte, and Cherokee—occurred during this time and further details can be found below.

a. Tubbs Fire

The Tubbs Fire (Sonoma and Napa Counties) began on October 8, 2017 near Highway 128 and Bennett Lane in Calistoga[1].

PG&E incurred $158.3 million related to the declared emergency in CEMA-eligible counties. In addition to the costs incurred by electric operations, our customer care organization assisted customers to rebuild after the Tubbs Fire. The customer care team spent time coordinating with operations, conducting customer outreach, escalating handling, assisting with clearance work, and helping customers with applications and our rebuild process. Additionally, capital expenditures

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1 CAL FIRE Report summary page 3: http://s1.q4cdn.com/880135780/files/doc_downloads/2019/05/TUBBS-LE80_Redacted.pdf.

were incurred to purchase electric meters for impacted customers. The $158.3 million can be broken down as follows.

TABLE 3-3
2017 TUBBS FIRE
COST ELEMENT BREAKDOWN OF COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	Capital MWC 95	Expense MWC IF	Total
1	Contract	$51,324	$46,774	$98,098
2	Labor	18,664	8,760	27,253
3	Materials	9,866	769	10,417
4	Other	14,076	8,038	22,502
5	Total	$93,929	$64,341	$158,271

1) Damaged Facilities

The Tubbs fire took 123 days to contain, burning through two counties and a total of 36,807 acres according to CAL FIRE.

The weather was a significant factor to the event start, with a strong pressure gradient caused by high pressure moving over the Great Basin and a low-pressure system approaching the coast of California developed beginning Sunday, October 8, 2017. This pressure gradient fueled the development of gusty offshore winds in the North Bay Area beginning early Sunday night; as a result, the National Weather Service of the San Francisco Bay Area put wind advisories and Red Flag warnings due to the critical fire conditions in the area. At the time of ignition, wind gusts were recorded around 30 mph out of the north. Winds strengthened in the ensuing hours, with peak gusts at 60+ mph on early Monday morning.

The hurricane-level winds caused the fire to spread very rapidly, causing significant damage to PG&E's electrical equipment. In total, 1,219 distribution poles, 224 transformers, 71 cross-arms, and approximately 1,651 spans of distribution conductor required repair or replacement.

2) Restoration Activities

During the Tubbs fire, PG&E crews were fully engaged with CAL FIRE and other first responders. PG&E embedded an Agency

Representative within the CAL FIRE command team. This provided a single point of contact for CAL FIRE and PG&E, and supported more effective communications, collaboration and alignment.

Due to the volume of damage and forecasted resource needs, it was determined that a base camp was needed, and PG&E established an Incident Command Post at that base camp as well.

In the city of Santa Rosa, eight thousand residents lived in Coffey Park and a neighboring subdivision which was almost destroyed, and required the most work in restoration, including trenching, and replacing of all new facilities.

FIGURE 3-1
COFFEY PARK SUBDIVISION, SANTA ROSA AFTER TUBBS FIRE

NOTE: https://www.businessinsider.com/santa-rosa-fire-coffey-park-neighborhood-2017-10.

PG&E crews have completely rebuilt the underground electric facilities by replacing cables and transformers destroyed during the high temperatures caused by the fire. This rebuild effort totaled approximately 22 miles of electric underground cable, and more than 17 miles of trenching for all the underground equipment.

Coffey Park reconstruction required:

- Over 100 gas & electric construction workers;
- 17 miles of trench;
- 22 miles of electric underground cable installed; and
- Over 75,000 work hours from gas and electric crews.

Similarly, in Larkfield Estates and Mark West Estates (subdivisions in Santa Rosa), underground electrical equipment, such as cables and transformers, were destroyed during the fire due to high temperatures and needed to be replaced. In Larkfield Estates and Mark West Estates, construction began in May 2018 and the trenching of more than four miles and the installation of approximately eight miles of underground electrical lines was complete in October 2018.

In the neighborhood of Fountaingrove (subdivision in Santa Rosa), the situation was different because much of the above ground electric facilities were destroyed in the wildfires, but much of the high-voltage distribution underground equipment and gas mains were not damaged and were still in service. The electrical equipment that was destroyed included underground secondary and service lines and other equipment. Replacing those items in Fountaingrove were less costly than in Coffey Park because the Fountaingrove neighborhood did not require extensive trenching since Fountaingrove has a more modern conduit system.

b. La Porte Fire

The La Porte Fire (Butte County) began on October 9, 2017 near La Porte Road and Oro Bangor Highway in Bangor.

PG&E incurred $0.9 million systemwide responding to this fire, of which $0.9 million is related to the declared emergency in CEMA-eligible counties. The $0.9 million can be broken down as follows:

TABLE 3-4
2017 LAPORTE FIRE
COST ELEMENT BREAKDOWN OF COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	Capital MWC 95	Expense MWC IF	Total
1	Contract	$33	$27	$60
2	Labor	331	48	379
3	Materials	104	–	104
4	Other	337	(15)	322
5	Total	$804	$61	$865

1) Damaged Facilities

According to CAL FIRE, the La Porte fire consumed 6,151 acres, destroyed 74 structures, and damaged two structures.

Weather station BNGC1, located approximately 2.7 miles south-south-west from the incident location, recorded a temperature of 69 degrees Fahrenheit, east-north-east wind speeds of four to six mph, wind gusts up to 30 mph, and a relative humidity of 10-12 percent around the time of the incident.[2] The La Porte fire was a wind driven fire influenced by both terrain and fuels. The fire was contained on February 9, 2018, but not before damaging PG&E facilities, including 38 poles, five transformers, four crossarms and six spans of distribution conductor.

2) Restoration Activities

The restoration was split with many accessible locations and many that were in-accessible and required specialized equipment. There was a tremendous amount of vegetation work required to remove all the trees that had fallen into the lines or were a hazard to fall into the lines.

c. Cherokee Fire

The Cherokee Fire (Butte County) began on October 8, 2017 off Cherokee Road and Zonalea Lane in Oroville. The Cherokee fire burned 8,417 acres and was contained on February 9, 2018.

2 Weather conditions per MesoWest (www.mesowest.utah.edu).

PG&E incurred $0.2 million systemwide responding to this fire, of which $0.2 million is related to the declared emergency in CEMA-eligible counties. The $0.2 million can be broken down as follows:

TABLE 3-5
2017 CHEROKEE FIRE
COST ELEMENT OF BREAKDOWN COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	Capital MWC 95	Expense MWC IF	Total
1	Contract	$5	$24	$29
2	Labor	53	40	93
3	Materials	17	–	17
4	Other	55	26	81
5	Total	$130	$90	$220

1) Damaged Facilities

According to CAL FIRE, the Cherokee Fire burned 8,417 acres, destroying six structures and damaging one other structure before the fire was contained.

Strong northerly winds occurred in the northern Sacramento Valley on Sunday, October 8, 2017 due to a strong pressure gradient caused by high pressure over the Great Basin and a low-pressure system approaching the coast of California. Wind gusts of 40-50 mph were recorded in the Sacramento Valley in the afternoon hours; by evening, winds had weakened, but were still breezy out of the north, around 20-30 mph. These winds, coupled with low fuel moistures and low humidity in the area, prompted the National Weather Service of Sacramento to issue wind advisories and Red Flag Warnings from Sunday until late Monday. Winds would remain breezy to locally gusty until Tuesday, October 10th, when winds would shift to southwest. Northerly offshore winds would then return overnight Wednesday into Thursday morning, with wind gusts maxing out around 30-35 mph. The North Valley division experienced 71 sustained outages on October 8th, affecting 17,319 customers; outage activity would linger into October 9th as winds subsided.

The damaged facilities included six poles, one transformer, one crossarm and four spans of distribution conductor.

2) Restoration Activities

PG&E crews were first to respond on October 9 and started restoration. Throughout the day crews mobilized and restoration work took two days. Damage from the Cherokee Fire was limited to poles, transformers, crossarms and conductor damage, and vegetation.

2. 2018 Event – Carr Fire

In A.19-09-012 PG&E requested cost recovery for the Carr Fire for costs incurred up to December 31, 2018. There have been additional costs for restoration activities related to the Carr Fire continuing through December 31, 2019.

The Carr Fire (Shasta County) began on July 23, 2018, in the area of Highway 299 and Carr Powerhouse Road, in the community of Whiskeytown, west of Redding. Costs incurred in 2019 for the Carr Fire are summarized below.

TABLE 3-6
2018 CARR FIRE
COST ELEMENT OF BREAKDOWN COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	Capital MWC 95	Expense MWC IF	Total
1	Contract	$1,289	$440	$1,729
2	Labor	385	121	506
3	Materials	(652)	(234)	(887)
4	Other	206	164	371
5	Total	$1,228	$491	$1,719

Additional information on the Carr Fire can be found in PG&E's opening testimony in A.19-09-012.[3]

Continued restoration activities are ongoing as customers return and rebuild. During 2019 PG&E continued to restore damaged distribution infrastructure in response to customers' demand. These activities included

3 See pages 2-28 to 2-37 of PG&E's opening testimony in A.19-09-012.

installation of 133 Overhead Facilities, 64 Underground Facilities, one Transformer, and five spans of distribution conductor.

3. 2019 Events

a. January-February Severe Storms

The January-February severe storms started January 5 and continued through February 27, 2019. This series of rainstorms swept across California bringing high winds, substantial precipitation, snow, and lightning.

PG&E incurred $258.5 million systemwide responding to these storms, of which $199.7 million is related to the declared emergency in CEMA-eligible counties. The $199.7 million is broken down as follows:

TABLE 3-7
2019 JANUARY FEBRUARY SEVERE STORMS
COST ELEMENT BREAKDOWN COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	Capital MWC 95	Expense MWC IF	Total
1	Contract	$29,353	$33,896	$63,249
2	Labor	24,530	32,392	56,922
3	Materials	8,924	184	9,108
4	Other	27,611	42,854	70,465
5	Total	$90,418	$109,327	$199,745

1) Damaged Facilities

A series of storm systems impacted PG&E's service territory in early 2019, bringing widespread rainfall, mountain snow, occasional gusty winds, and infrequent isolated thunderstorms. Over the course of two months, January and February, the service territory received between 10-20 inches of precipitation along the Sacramento Valley floor, 10-15 inches through the San Joaquin Valley, and upwards of 25 inches of precipitation accumulation through the Sierra and across elevated terrain surrounding the valleys. Periods of breezy to locally gusty winds would occasionally accompany the precipitation, with the strongest gusts around 45-50 mph over peaks and favored gaps. Isolated thunderstorms would also sometimes accompany the weather systems, responsible for over 1,000 cloud-to-ground lightning strikes in the service territory. Moderate to heavy mountain snowfall was also observed, with snow elevations sometimes dropping to around 2,000-foot elevation or lower.

Total customers impacted during this event were over 2.3 million customers throughout the service territory.

The damage inflicted on the overhead distribution facilities included whole trees and large limbs falling through the overhead lines, and onto poles, and pole mounted equipment. In response to these storms, PG&E repaired or replaced 1,287 poles, 1,007 transformers, 936 crossarms and 4,660 spans of distribution conductor.

2) Restoration Activities

Resource plans were created to prearrange crews to standby to ensure adequate staffing levels in the divisions predicted to be the hardest hit. These plans included staffing for 911 Standby and the deployment of Rapid Assessment Teams from the Resource Management Centers. These teams were used to augment local Estimators and Troublemen in the completion of damage assessment. Additional 911 Standby teams were also mobilized to respond to outages where a public safety agency needed assistance. These teams are trained to standby at the location, protect the public, and relieve the public safety agency and wait for a Troubleman or make-safe crew to arrive.

PG&E focused initial efforts on assessment and identification of damaged facilities. The information gathered during the assessment phase was used to determine the number of crew resources needed and materials required to quickly restore service to customers. During the damage assessment phase, information was also gathered to help determine ways to temporarily reconfigure the system to restore service to the greatest number of customers possible prior to the completion of major repairs. The electric distribution system was reconfigured by opening and closing field switches to isolate damaged sections and re-energize intact sections via alternate routes where possible.

In the areas of heavy winds and rain, downed trees and debris blocked roadways and prevented personnel attempting to respond from accessing outage locations. To allow responding personnel to access these areas, tree crews with excavating equipment needed to remove trees and debris. Overhead line repairs included repairing and replacing damaged poles, pole hardware, and pole mounted equipment; removing foreign objects from the overhead lines; and splicing and repairing conductors.

Temporary repairs were made in certain situations to eliminate unsafe conditions and help restore service more quickly. Permanent repairs were made, and normal operating system configuration was restored via field switching as soon as resources were available and could be efficiently used to do so.

b. October 26 and 29 Wind Events

PG&E incurred $17.2 million systemwide responding to this event, of which $17.2 million is related to the declared emergency in CEMA-eligible counties. The $17.2 million can be broken down as follows:

TABLE 3-8
2019 OCTOBER WIND EVENTS
COST ELEMENT BREAKDOWN OF COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	Capital MWC 95	Expense MWC IF	Total
1	Contract	$4,242	$2,835	$7,076
2	Labor	1,936	2,911	4,847
3	Materials	992	3	995
4	Other	2,094	2,144	4,238
5	Total	$9,263	$7,893	$17,156

1) Damaged Facilities

PG&E conducted two Public Safety Power Shutoff (PSPS) events (October 26, and October 29) in response to catastrophic wildfire risk presented by offshore wind events combined with low humidity levels and critically dry fuels. These PSPS events significantly reduced the response and restoration costs presented in this chapter for the October wind events.

The overlap of the two events resulted in approximately 12 hours of daylight restoration time available for patrols and restoration for the October 26 PSPS event. The customers who were affected by both events experienced a cycle of either: (1) being de-energized and restored for a short period of time before being de-energized again, or (2) being de-energized and remaining de-energized over the duration of both events. Because PG&E is unable to determine which wind event caused the damage discussed herein, the damage statistics for both events have been consolidated.

PG&E personnel patrolled all sections of de-energized PSPS circuits for safety prior to re-energizing.[4] During those patrols, PG&E discovered approximately 554 instances of wind-related damage or hazard issues associated with its facilities across impacted divisions that required remediation prior to re-energizing. These included 398 instances of damage to PG&E's assets due to high winds. Of those instances, 315 instances were due to tree branch failures that caused damage to PG&E assets. In each case, PG&E repaired or replaced the damaged equipment prior to re-energizing. In addition to these instances of wind-caused damage, PG&E personnel discovered 156 instances of document hazards, such as branches found lying across conductors, which were cleared prior to re-energizing.

398 cases of damages:

- 315 damage cases where vegetation was identified as the cause;
- 83 damage cases of wind-caused asset damage; and
- 156 cases of hazards.

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4 PG&E's "AMENDED POST-PSPS EVENT REPORT FOR OCTOBER 26 & 29, 2019." July 24, 2020. Page 9.

On October 26th and October 29th, a strong offshore wind event occurred between late October 26, 2019, to early October 28, 2019, due to an especially strong pressure gradient caused by a weather system moving over the Great Basin. Critical fire potential conditions persisted due to continued dry weather, dry fuels, and multiple offshore wind events throughout the territory; in response, National Weather Service offices across the state of California issued Red Flag Warnings and High Wind Advisories. The event was forecasted to be stronger than the October 2017 offshore wind event, with analyses showing to be in the 99th percentile of wind events, which would occur once every 15 years on average. PG&E performed a large-scale PSPS to reduce the risk of wildfire ignitions in impacted areas. Winds strengthened overnight into the morning of the 27th; wind gusts of around 70-80 mph along elevated terrain were observed, with a maximum wind gust of over 100 mph in the North Bay hills. Relative humidity was also observed to be critically low, ranging from single digit to mid-20 percent throughout wind impacted areas. Winds would gradually weaken through the day, with the exception of the far south where offshore winds would continue until the morning of October 28th.

During this time there were over 967,700 customers impacted with the majority in Humboldt, North Bay, Sierra and Sonoma divisions.

Another weather system moved into the Great Basin on Tuesday, October 29, 2019, bringing offshore northerly winds throughout the northern half of the territory. A strong pressure gradient would encourage the development of gusty winds overnight into the morning of October 30th; due to the combination of winds and critically dry fuels, the National Weather Service issued multiple Red Flag Warnings to highlight continued critical fire potential. A PSPS was executed by PG&E to reduce wildfire ignition risk in critically impacted areas of the territory. Winds would strengthen overnight, with peak wind gusts around 60-65 mph over elevated terrain. Relative humidity was also low, ranging from single digit to low 20 percent overnight. By the morning of October 30th winds in the northern half of California mostly weakened to below critical levels but winds would not weaken in Southern Kern division and the Tehachapi Mountain range until the morning of October 31.

The total damage to overhead distribution facilities was widespread across the service territory. The damage included 238 Poles, 94 Transformers, 194 Crossarms, and 711 spans of distribution conductor.

2) Restoration Activities

In areas of heavy winds, downed trees and debris prevented response personnel from accessing outage locations. To allow response personnel to access these areas, tree crews with excavation equipment needed to remove trees and debris. Overhead line repairs included repairing and replacing damaged poles, pole hardware, and pole mounted equipment; removing foreign objects from the overhead lines; and splicing and repairing conductors.

Temporary repairs were made in certain situations to eliminate unsafe conditions and help restore service more quickly. Permanent repairs were made, and normal operating system configuration was restored via field switching as soon as resources were available and could be efficiently used to do so.

c. Glencove Fire

The Glencove Fire (Solano County) began on October 27, 2019 off Glen Cove Parkway and Lookout Drive south of Vallejo.

PG&E incurred $0.2 million systemwide responding to this fire, of which $0.2 million is related to the declared emergency in CEMA-eligible counties. The $0.2 million is broken down as follows:

TABLE 3-9
2019 GLENCOVE FIRE
COST ELEMENT BREAKDOWN OF COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	Capital MWC 95	Expense MWC IF	Total
1	Contract	$138	–	$138
2	Labor	19	–	19
3	Materials	16	–	16
4	Other	26	–	26
5	Total	$200	–	$200

1) Damaged Facilities

On October 27, 2019 winds gusting to over 40 miles per hour and relative humidity of less than 20 percent were recorded at the Napa County Airport, located ten miles north-northwest of the location on the morning of the event.

The fire burned 140 acres, damaging the California Maritime Academy facilities and PG&E facilities near the California Maritime Academy, impacting 8,400 distribution customers.

FIGURE 3-2
(GLENCOVE FIRE)

NOTE: Glencove Fire south of south of Vallejo, California, northeast of the I-80 Carquinez Bridge, October 27, 2019. Photo by @arrowstewtoe. https://wildfiretoday.com/?s=glencove&monthnum=&year=&states_provinces=&countries=&topics=.

2) Restoration Activities

The following day, on October 28, 2019, a PG&E repair crew installed three poles, and two spans of distribution conductor.

d. Bethel Island Fire

October 27, 2019 a fire occurred on East Cypress Rd and Bethel Island Road. The fire burned a total of approximately 200 acres, with several structures being damaged. The high wind speeds that morning attributed to the fire being spread so quickly.

PG&E incurred $0.02 million systemwide responding to this fire, of which $0.02 million is related to the declared emergency in CEMA-eligible counties. The $0.02 million can be broken down as follows:

TABLE 3-10
2019 BETHEL ISLAND FIRE
COST ELEMENT BREAKDOWN OF COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	Capital MWC 95	Expense MWC IF	Total
1	Contract	$22	–	$22
2	Labor	1	0	1
3	Materials	–	–	–
4	Other	1	0	1
5	Total	$24	$0	$24

Please see below for the description of PG&E's response. Further information is set forth in the workpapers supporting this chapter.

1) Damaged Facilities

An offshore wind event occurred over the weekend of October 26-28, 2019, due to a weather system sliding into the Great Basin, creating a strong pressure gradient in the territory. The potential for strong offshore winds and existing dry fuels in the area prompted the National Weather Service Office in Monterey to issue a Red Flag Warning throughout the Bay Area, including the area near Oakley and Bethel Island. Strong and gusty offshore winds began overnight on the 26th, with peak wind gusts in northern East Bay recorded around 50-60 mph. Winds would weaken through the day on the 27th but would remain locally gusty in the area for most of the day.

The damaged facilities included one Jumper and one span of distribution conductor, resulting in sustained outages to 910 customers.

2) Restoration Activities

PG&E performed field switching to restore service to 910 affected customers. After the fire, the transformers were inspected further and eventually put back into service as they were not damaged.

e. Camino Fire

The Camino Fire started on October 27, 2019 and burned about five acres, destroying a tennis club building, an outbuilding and minor damage to a residential home.

PG&E incurred $0.01 million systemwide responding to this fire, of which $0.01 million is related to the declared emergency in CEMA-eligible counties. The $0.01 million can be broken down as follows:

TABLE 3-11
2019 CAMINO FIRE
COST ELEMENT BREAKDOWN OF COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	Capital MWC 95	Expense MWC IF	Total
1	Contract	$7	–	$7
2	Labor	1	–	1
3	Materials	–	–	–
4	Other	2	–	2
5	Total	$10	–	$10

Please see below for the description of PG&E's response. Further information is set forth in the workpapers supporting this chapter.

1) Damaged Facilities

A weather system moved into the Great Basin on Saturday, October 26, creating an especially strong N-S pressure gradient in the PG&E territory. The pressure gradient was responsible for encouraging the development of strong and gusty offshore northerly winds in the East Bay Area hills that night through the afternoon of October 27th, with wind gusts reported around 60-70 mph in the area. The combination of the strong winds and low fuel moisture prompted the National Weather Service Office in Monterey to issue a Red Flag Warning for the area. Winds began to weaken overnight into October 28th but remained locally gusty in the area. The damaged facilities included one pole and two spans of distribution conductor.

2) Restoration Activities

A PG&E Troubleman performed switching and operational work to make the area safe and restore customers where feasible. The repair work concluded the morning of October 29, 2019 and included the replacement of one pole, and two spans of distribution conductor and all associated hardware and conductors. All remaining customers were restored at 1445 hours on October 29, 2019.

D. Conclusion

This chapter describes PG&E's electric distribution restoration activities associated with the CEMA Events that occurred between 2017 and 2019 with costs ending December 31, 2019. As discussed in this chapter, PG&E's costs incurred responding to these events were reasonable and therefore should be approved in their entirely.

PACIFIC GAS AND ELECTRIC COMPANY

2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS

CHAPTER 3

ATTACHMENT A

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This attachment provides an overview of Pacific Gas and Electric Company's (PG&E or the Company) electric emergency response process.

PG&E's response to electric emergencies is designed to comply with the regulatory expectations contained in General Order (GO) 166, "Standards for Operation, Reliability, and Safety During Emergencies and Disasters." The purpose of these standards is to ensure that jurisdictional electric utilities are prepared for emergencies and disasters in order to minimize damage and inconvenience to the public which may occur as a result of electric system failures, major outages, or hazards posed by damage to electric distribution facilities. These standards will facilitate the California Public Utilities Commission's (Commission) investigations into the reasonableness of the utility's response to emergencies and major outages. Such investigations will be conducted following every major outage, pursuant to and consistent with Public Utilities Code Section 364(c) and Commission policy.

- Standard 1 – Prepare an emergency response plan and update the plan annually.
- Standard 2 – Enter into mutual assistance agreements with other utilities.
- Standard 3 – Conduct annual emergency training and exercises using the utilities emergency response plan.
- Standard 4 – Develop a strategy for informing the public and relevant agencies of a major outage.
- Standard 5 – Coordinate internal activities during a major outage in a timely manner.
- Standard 6 – Notify relevant individuals and agencies of an emergency or major outage in a timely manner.
- Standard 7 – Evaluate the need for mutual assistance during a major outage.
- Standard 8 – Inform the public and relevant public safety agencies of the estimated time for restoring power during a major outage.
- Standard 9 – Train additional personnel to assist with emergency activities.

- Standard 10 – Coordinate emergency plans with state and local public safety agencies.
- Standard 11 – File an annual report describing compliance with these standards.
- Standard 12 – Be subject to a restoration performance benchmark for major outages.
- Standard 13 – Be subject to a call center performance benchmark for major outages.

In compliance with GO 166 Standard 1, PG&E has created the Company Emergency Response Plan (CERP). The purpose of CERP is to assist PG&E personnel with safe, efficient and coordinated response to an emergency incident affecting gas or electric generation, distribution, storage and/or transmission systems within the PG&E service territory or the people who work in these systems.

The CERP provides a number of functions including:

- Providing a broad outline of PG&E's organizational structure;
- Describing actions undertaken in response to emergency situations;
- Presenting a response structure that clearly defined roles and responsibilities; and
- Identifying coordination efforts with outside organizations (e.g., government, media, other gas and electric utilities, essential community services, vendors, public agencies, first responders and contractors).

The Electric Annex, one of the many lines of business (LOB) and hazard-specific annexes within the CERP provides an outline of PG&E's electric Emergency Management Organizational (EMO) structure, roles and responsibilities, and describes the activities undertaken in response to electric emergency outage situations.

The Electric Annex is a key element to ensure the Company is prepared for emergencies in order to minimize damage and inconvenience to the public, which may occur as a result of electric system failures, major outages, or hazards posed by damage to electric facilities.

The Electric Annex's purpose is to serve as:

- The recovery and response plan to govern electric operations during emergency events;
- A guide to develop an overall strategy for managing a response to specific disaster;

- A tool to educate and train the Electric EMO and key stakeholders on how to execute the plan;
- The basis for developing annual drills and exercises to test the organization's ability to execute emergency response procedures; and
- The repository for capturing how continuous improvement efforts impact the Electric EMO emergency operations efforts.

The processes and procedures contained in both the CERP and Electric Annex drive the response strategies and tactics used by PG&E to safely and efficiently restore service during emergency situations, such as a Catastrophic Event Memorandum Account (CEMA) event.

PG&E's service territory is divided into four regions. These regions, in turn, are divided into 19 divisions. PG&E's electric system consists of approximately 81,000 circuit miles of overhead distribution lines, approximately 26,000 circuit miles of underground lines, and over a million distribution line transformers. The overhead lines, supported by approximately 2.4 million poles, are particularly susceptible to damage from catastrophic events like storms and fires. PG&E's Distribution System Operations (DSO) monitors the distribution grid to identify outages and directs the scheduling and dispatch of field personnel to address identified abnormal conditions. PG&E typically identifies outages through alarms from field devices such as circuit breakers or reclosers, SmartMeter™ data, notifications from police and fire departments, preventive maintenance patrols and inspections, and/or by telephone calls from customers who are experiencing an outage. Once outages have been identified, personnel are directed to address the issues.

Part of PG&E's proactive approach to anticipate events is the use of the DSO Storm Outage Prediction Project (SOPP) model. This model evaluates potential impacts to the electric system from forecast adverse weather, translates this into expected outage activity, and estimates the resources required to respond effectively. The model has evolved into a key component of the PG&E Electric Emergency Recovery Program (ERP). Using the detailed information that the DSO SOPP model provides, PG&E can preschedule resources several days in advance of an anticipated major adverse weather event. DSO SOPP model improvements have enabled PG&E to become more effective in preparing for emergency outages in support of public and system safety and work efficiency, for major events, and for smaller and more frequent day-to-day weather challenges.

PG&E follows a defined process to ensure appropriate objectives are addressed in the following priority:

1) Make Safe – Field personnel act to address hazardous conditions to support public and employee safety.
2) Assess – Field personnel assess the outage location to identify the outage cause (if possible), determine the necessary resources to address the situation (material, equipment, and personnel) and estimate the time necessary to make repairs.
3) Communicate – Field personnel and system operators (located in PG&E's distribution control centers) work together using various technologies to provide customers and public agencies with outage information, such as the cause of an outage and Estimated Time of Restoration (ETOR).
4) Restore – After making the conditions safe, assessing the situation, and beginning the communication process, field personnel and system operators work together to restore service. This occurs through a combination of reconfiguring the distribution grid and repairing damaged facilities, depending on the nature of the event.

PG&E's CERP provides the framework for PG&E's response to gas and electric emergency situations. Emergency situations range from routine outages (e.g., dig-ins to electric facilities) to major natural disasters (e.g., earthquakes and major storms). Local control and management may be sufficient to respond to routine outages. Natural disasters, however, may require a larger coordinated response of resources.

A. Incident Levels

PG&E has five incident levels, which are described below. PG&E's incident levels function as a decision-support tool that helps determine the actions PG&E may need to employ. Level 1 emergencies are classified as routine. Level 2 emergencies may be classified as routine if the local Operational Emergency Center (OEC) is not activated or is activated for communications only. OEC communications-only activations are used for pre-staging of resources, resource support for other affected OECs, significant media impacts, large non-incident major events (e.g., conventions or major sporting events), or outages requiring significant environmental impact. These activities are all considered Routine Emergency.

Major Emergencies are typically Level 2 through 5 emergencies. A Level 2 emergency would be considered major if an OEC is activated. OECs are positioned within each region and are activated separately in individual division locations. OECs can be activated when a division exceeds the total number of outages (transformer level and above outages) noted in Table 2A-1 below and field resources (i.e., Troublemen and crews) to sufficiently support outage activity have been exhausted. The outage numbers vary by division due to differences in geographical size, electric infrastructure design (e.g., overhead versus underground, urban versus rural), outage history, and resource availability. Occasionally, OECs will activate based on anticipated outage activity determined by the DSO SOPP model to support public safety and outage restoration.

TABLE 3A-1
OEC ACTIVATION CRITERIA BY DIVISION

Line No.	Division	Number of Transformer Level and Above Outages Required for OEC Activation
1	Central Coast	9
2	De Anza	5
3	Diablo	5
4	East Bay	5
5	Fresno	8
6	Kern	5
7	Los Padres	6
8	Mission	5
9	North Bay	5
10	Humboldt	7
11	Sonoma	5
12	North Valley	8
13	Peninsula	5
14	Sacramento	6
15	San Francisco	5
16	San Jose	5
17	Sierra	9
18	Stockton	6
19	Yosemite	8

PG&E Incident Levels:

- Level 1 – Routine: A Level 1 emergency is typically at the local level, involving a limited number of customers with an anticipated restoration response time within 24 hours. In a Level 1 emergency, PG&E can respond sufficiently using its standard operating mode and local resources. The local operating departments coordinate resource deployment in a Level 1 emergency. This level does not require the activation of an emergency center.

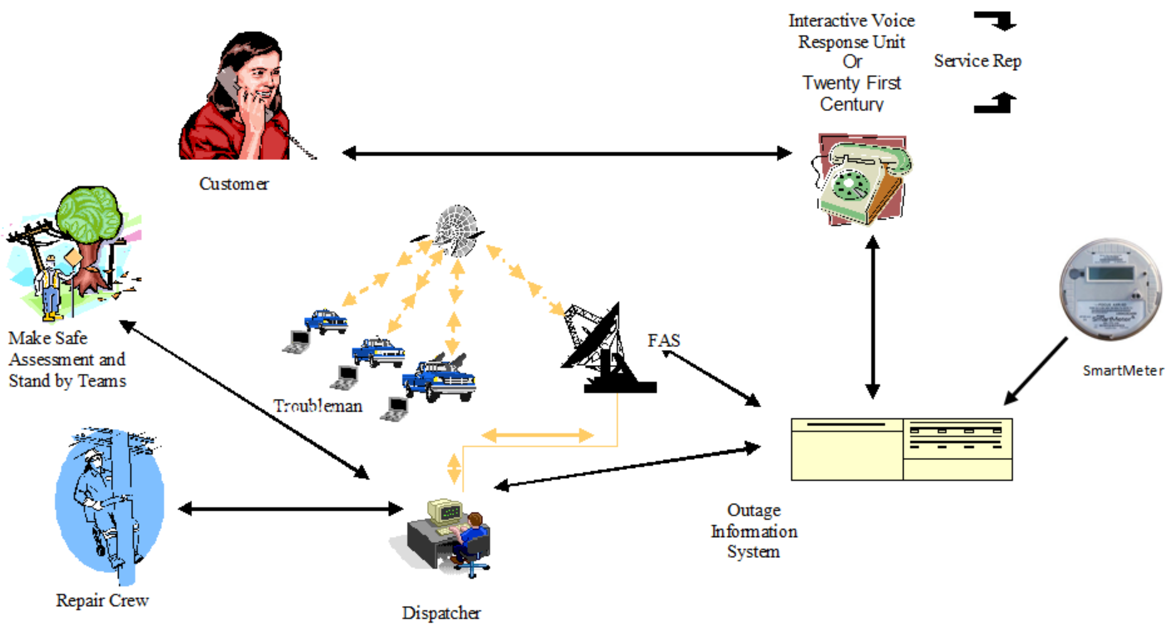
- Level 2 – Elevated: Level 2 emergencies are defined as a pending potential incident or a local emergency that may require more than routine operations response. Resources are mainly local, but there is a possibility that resources may need to move within the region. For Level 2 emergencies, an OEC may be activated for communications only or fully activated to provide oversight and support at a divisional level.
- Level 3 – Serious: Level 3 emergencies are serious incidents involving large numbers of customers. Resources mainly move within the region, but may need to move between regions. In Level 3 emergencies, OECs are activated to direct and coordinate the personnel necessary to assess damages, secure hazardous situations, restore service, and communicate status information internally and externally. Regional Emergency Center (REC) and Emergency Operations Center (EOC) activation is possible. The REC provides oversight and support to the OEC(s) at a region level. As an event escalates, the REC becomes the point of contact for information and managing escalated OEC issues.
- Level 4 – Severe: Level 4 is an escalating incident with companywide impact or extended multiple emergency incidents that impact a large number of customers. Resources move between regions, general contractors are used, and mutual aid may be needed. During a Level 4 emergency, the OEC, REC and EOC are activated. Additionally, the Emergency Preparedness and Response team assumes incident command.
- Level 5 – Catastrophic: Level 5 is a catastrophic event that includes multiple emergency incidents, impacts a large number of customers, has a significant cost, and significant infrastructure risk/damage. This level of emergency affects the entire Company and the ability to conduct business operations. The full mobilization of Company resources is needed to respond, and mutual aid resources are needed. During a Level 5 event, all emergency centers are activated, and the Emergency Preparedness and Response team assumes incident command.

B. Outage Communication

PG&E relies on a series of interconnected systems, well-defined work processes, and well-trained personnel to provide outage information to customers. PG&E's Outage Information System (OIS) is the key "operational" system that links field information (e.g., outage locations, causes, resource assignments, and estimates of restoration) to PG&E's Customer Information System, which is used in the call centers to relay this information to customers. This system addresses outages affecting all customers including single customer outages.

PG&E uses the OIS to assist in deploying resources to address outages and to provide outage information to customers. Figure 3A-1 depicts the outage communication system.

FIGURE 3A-1
OUTAGE COMMUNICATION SYSTEM



The OIS uses outage information from the field to generate information to manage resources and communicate outage information. These inputs can take the form of:

- Customer telephone calls to report an outage;
- Outage information from automatic system devices located on PG&E's facilities;
- Reports from field personnel during their storm response activities; or

- Reports from emergency agencies.

After entering outage information from these sources into the OIS, system operators can identify and locate the equipment involved in the outage by using detailed information on the circuit and the equipment information stored in a database.[1] Customer calls produce outage locations in the OIS through the customers' telephone numbers. The OIS is able to associate each customer call with a specific service transformer, based on the phone number or service account identifiers provided by the customer. With this data, the OIS can identify the operating device (e.g., a circuit breaker, based on the pattern of service transformers receiving trouble calls) that serves the affected area.

As information is recorded in the OIS, it becomes accessible to customers through PG&E's call center resources. These resources include Customer Service Representatives, as well as PG&E's high-volume Interactive Voice Response Units. As the outage progresses and more information becomes available, PG&E can provide customers with increasing amounts of information, such as an estimated time of arrival for field response personnel (e.g., Troublemen and construction crews), the outage cause (if known), and ETOR when available.

C. Emergency Recovery Cost Management

PG&E divisions follow specific procedures for recording expenditures associated with the response and repair of damage to Company facilities. During the occurrence of a major event, affected divisions are instructed to separately track and report the costs incurred for restoring utility service and repairing damaged facilities associated with that event. The divisions segregate these costs by creating "specific orders"[2] to capture repair, replacement, and service restoration costs. These specific orders are created for both capital and expense and for both overhead and underground restoration work, by county

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[1] It is unnecessary to input information from field devices connected to a distribution automation system, as information from these devices populates the OIS automatically.

[2] A "specific order" is a term used in PG&E's SAP accounting system to refer to orders established to record costs related to particular tasks or given scope of work. Once the tasks or projects are complete, the specific orders are closed. These specific orders differ from "standing orders." Standing orders are used to record costs for day-to-day ongoing utility operations and are not closed following completion of specific tasks or projects.

within each division. The orders are created using a specific naming convention to identify the business region, division, county, and event for which the order is created.

The role of the Finance Section Chief within the OEC or the Incident Management Team is responsible for monitoring costs, developing financial accounting strategy and providing charging guidance during the incident. Costs are closely monitored and reviewed to ensure they are recorded in the correct major work category (MWC) and aligned with the correct LOB. Where an event affects a number of PG&E facilities across wide geographic regions, multiple specific orders are used to ensure the proper reporting and control of system repairs and restoration work. PG&E's Business Finance Department, ERP Manager, and the affected divisions review the orders to ensure that the costs charged to the specific orders occurred within the timeframes of the event, are in accordance with the major event charging guidelines, and were in the counties covered by the orders.

D. Incrementality

CEMA event costs are explicitly removed from Electric Distribution's historical spending when the Electric Distribution's General Rate Case (GRC) forecast is developed. In the GRC, PG&E forecasts and records in MWCs IF (Expense)[3] and 95 (Capital)[4] all costs associated with electric distribution major emergency response that are <u>not</u> declared disasters (i.e., non-CEMA events).[5] The MWC IF and MWC 95 forecast in the GRC are typically developed by taking an average of historical spending.

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3 Major emergency expense work captured in MWC IF can involve, but is not limited to, splicing conductor, replacing insulators, re-sagging conductor, pre-treating poles or basically any work that involves a repair.

4 Major emergency capital work captured in MWC 95 involves the replacement of a capital plant asset, such as a pole, cross arm, or a piece of line equipment.

5 Beginning in 2014, PG&E began using the Major Emergency Balancing Account (MEBA), as authorized by the CPUC in Decision 14-08-032. With the introduction of the MEBA, all non-CEMA MWC 95 and MWC IF major emergency activities are recorded to the MEBA. In a given year where PG&E incurs a lesser amount of costs relative to the authorized revenues for responding to major emergencies for that year, the difference is returned to customers the following year. If PG&E incurs a greater amount of costs responding to major emergencies in a given year relative to the authorized revenues for responding to major emergencies during that year, the difference is recovered from customers the following year.

PG&E operating departments plan their labor by month, and specifically plan a set amount of units of work for normal business operations to respond to day-to-day emergencies and for restoration work associated with a major emergency.[6] A unit of work is a Priority-A Electric Corrective (EC) tag.[7] As with costs, units of work are forecasted by both capital and expense. All emergency repairs performed on the distribution system are also captured in the form of units. Operating departments' planned units of work for responding to emergencies are based on historical recorded expenditures and unit volume.

Responding to emergency situations is one of PG&E's highest priorities. When a major event impacts the service territory, scheduled work is put on hold, and resources are re-deployed to the higher priority work of restoring customers. Thus, in an emergency, planned units of work for normal day-to-day business operations may be displaced by the units of work for responding to the emergency.

The planned work displaced by emergency work must still be completed. This work is re-prioritized and re-scheduled, potentially causing other scheduled work to also be moved farther out in time. It can take from a few months to a year or more, depending on the magnitude of the emergency and other factors, such as the use of overtime, to make up the work in the schedule.

PG&E uses a 5-year average to calculate Major Emergency planned hours, units and costs, Major Emergency work in 2017 and 2019 was significantly over plan due to the higher-than-forecasted storm and fire activity. Figure 3A-2 shows the Major Emergency planned versus actual costs, as well as the costs of CEMA-qualifying events within the date range of 2017-2019.

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6 A "major emergency" is any event that results in PG&E activating one of the Company's OECs.

7 A unit of work in the ERP is a Priority A EC Notification. A unit of work is synonymous with a work location as defined by the Electric Distribution Preventative Maintenance Manual. Expense work locations are specific to the item repaired. For example, where multiple spans of wire are down, each span is considered a work location and an EC notification is generated for each. Capital work locations are specific to the pole (all assets inclusive) and a span of wire on either side. For example, in the case of one pole, the two contiguous spans of wire down and requiring replacement; the downed pole/span combination is considered one work location. Therefore, only one EC notification is required for the pole and the wire.

FIGURE 3A-2
ELECTRIC DISTRIBUTION PLANNED VERSUS ACTUAL COSTS
(MWC IF AND MWC 95) JANUARY 2017 THROUGH DECEMBER 2019
(THOUSANDS OF DOLLARS)

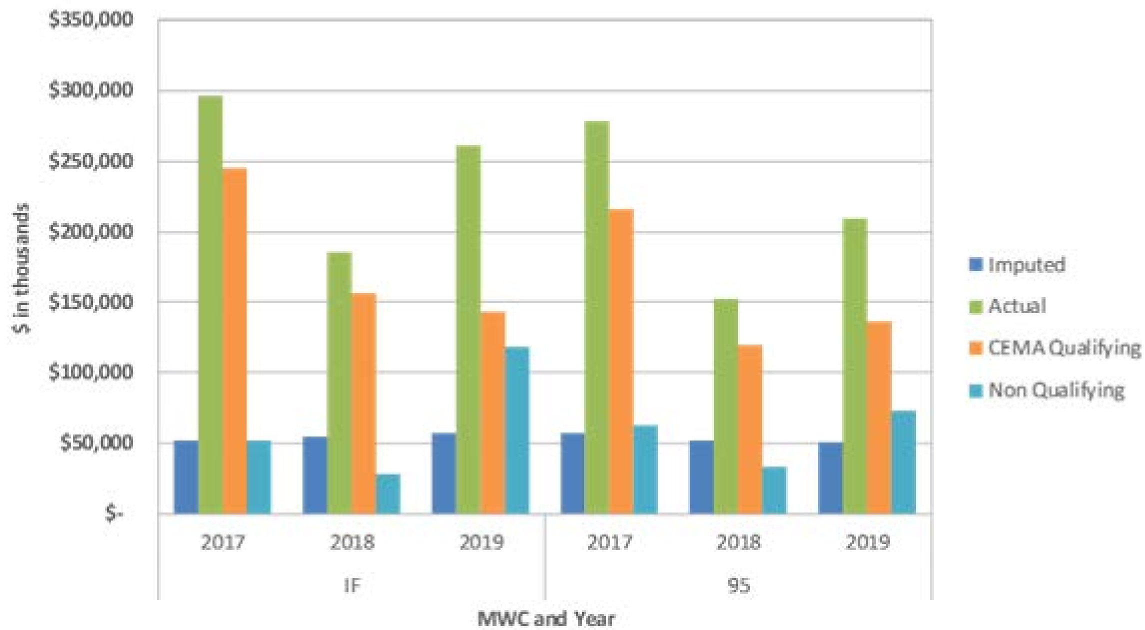

Figure 3A-2 shows that actual expenditures exceeded the budget in expense and capital between 2017 and 2019. This reflects the significant impact the volatile climate had on PG&E's infrastructure.

Figure 3A-3 shows the planned, actual and CEMA-qualifying units from 2017 through 2019.

FIGURE 3A-3
ELECTRIC DISTRIBUTION PLANNED VERSUS ACTUAL UNITS
(MWC IF AND MWC 95) JANUARY 2017 THROUGH DECEMBER 2019

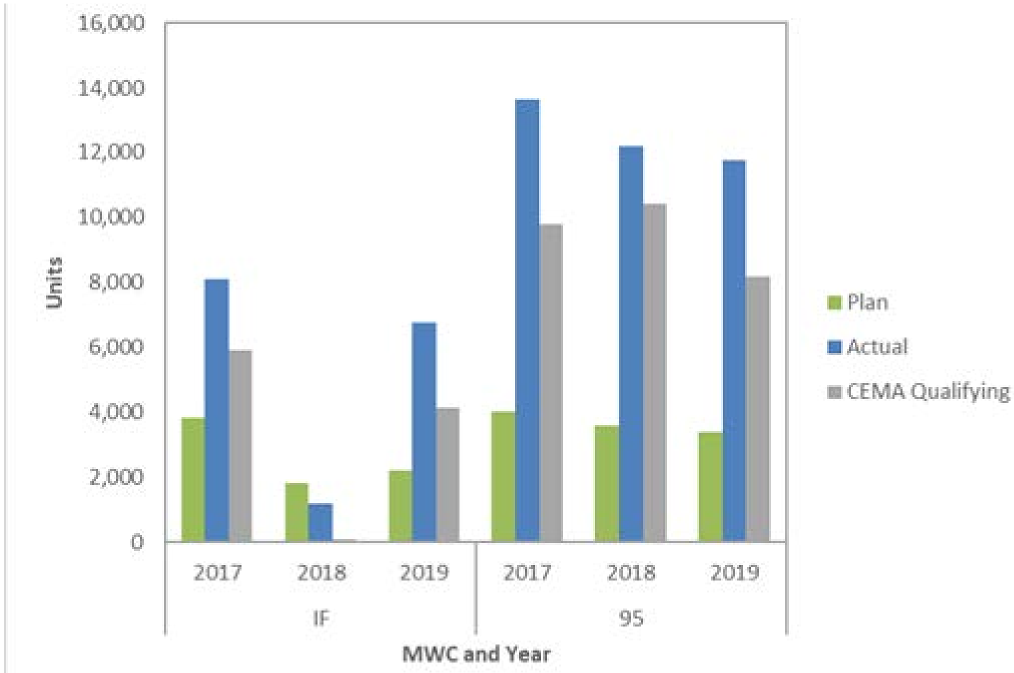

Figure 3A-3 shows the magnitude and the severity of the 2017 storms and wildfires. The actual and CEMA-qualifying are significantly over plan. In 2017, the CEMA-qualifying events alone represented 155 percent of the expense (MWC IF) planned units and 245 percent of the capital (MWC 95) planned units. In 2018, the CEMA-qualifying events represented 5 percent of the expense (MWC IF) and 289 percent of the capital (MWC 95) planned units. In 2019, the CEMA-qualifying events represented 187 percent of the expense (MWC IF) and 240 percent of the capital (MWC 95) planned units.

Incrementality is discussed in greater detail in Chapter 8 of this application

E. Cost Reasonableness

The costs PG&E incurred in responding to the catastrophic events described above are reasonable as described in this section. First, the activities PG&E performed are in accordance with GO 166 requirements, as described in Chapter 3, Attachment A. Second, PG&E tracks a number of performance metrics for each event which illustrate the reasonableness of the response. These metrics are reviewed after the events to drive continuous improvement and efficiency in PG&E's emergency response.

1. PG&E's Response Was Driven by the Requirements of GO 166[8]

There are many factors that will drive the strategy and tactics of PG&E's response to a catastrophic event including; incident complexity, volume of damage, and duration of customer impact. All of these then drive the resources required to respond and restore customers as quickly as possible. The expectation of the CPUC, as provided in the Standards within GO 166, is to safely and quickly restore service to customers. PG&E's CERP[9] and Annexes, as required by Standard 1, contain processes, procedures and guidelines to facilitate compliance with the ten sections of the standard.

As discussed in Section D of this testimony with respect to each of the individual incidents, PG&E's response actions were consistent with those requirements and the costs it incurred were in support of achieving those objectives. For example, as contemplated by Standard 1, PG&E has coordinated internally in the gathering and dissemination of information, established response priorities, implemented proactive deployment and allocation of resources from across the service territory and coordinated activities to restore service to impacted customers.

PG&E has further demonstrated the focus on public and employee safety through: (1) the use of 911 Standby resources to relieve public safety agencies within 60 minutes and the use of base camps to get crews and material closer to the work, limiting driving risk exposure; (2) the execution of dynamic damage assessment strategies to assess infrastructure damage and mobilize additional resources in the form of Rapid Assessment Teams to expedite assessment and restoration of service; (3) development and communication of restoration priorities during each incident both internally and externally during wildland fire situations; and (4) using mutual assistance to reduce outage duration.

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8 Chapter 3, Attachment A contains a detailed discussion of GO 166 requirements which drive the response efforts made by PG&E during these CEMA events.

9 In compliance with GO 166, Standard 1, PG&E has created the CERP. The purpose of CERP is to assist PG&E personnel with safe, efficient and coordinated response to an emergency incident affecting gas or electric generation, distribution, storage and/or transmission systems within PG&E's service territory or the people who work in these systems. See Chapter 3, Attachment A for more information.

2. Performance Metrics Demonstrate the Effectiveness of PG&E's Response

PG&E's top priorities when responding to catastrophic events is the safety of the public, first responders, and employees, and the timely restoration of service to customers. In a catastrophic emergency response setting, costs are affected by many different factors depending on the nature of the event and response. Therefore, it is not appropriate to judge the reasonableness of costs incurred on a per unit basis as may be done in other circumstances. Rather, it is appropriate to look to the activities undertaken given the circumstances and the overall level of success of the response.

Response to a catastrophic event differs in many ways compared to work performed in a "normal" setting. PG&E may incur additional costs during these types of events, such as warehouse and telecom services, base camp setup and operational costs, standby labor, overheads, and others. Total costs for catastrophic events vary widely due to severity, resource requirements, type of event and many other factors. As described above, PG&E's SOPP model outputs add visibility to the potential complexity of the incident, area of greatest impact and resource and material needs. This information is used to assist PG&E in executing an efficient response. PG&E's three warehouse facilities contain stores of material and their strategic placement in the service territory support rapid mobilization of materials to service centers and lay down yards during response. During a catastrophic event, PG&E uses the standards set forth in GO 166 and the CERP in order to appropriately and reasonably respond. For example, PG&E's Resource teams monitor assessment and restoration rates to help identify how many and where crews are needed and if contract or Mutual Assistance resources will need to be requested. Operational calls are held with OEC and REC Commanders to validate the resource plan and identify unique needs for specialize equipment to mitigate access or geographic challenges and improve restoration performance. The development of a common operating picture confirms the number of resources required and ensures we are not moving resources unnecessarily or bringing on additional external resources that are not required for restoration.

In accordance with the 2016 CEMA settlement, to help better understand PG&E's emergency response performance across CEMA events, Tables 3-3 and 3-4 below provides a comparative perspective of the metrics used to measure response performance for the winter storms and wildland fires included in this application. PG&E reviews its performance with the Incident Management Team and responders within the Lines of Business after the fact in an effort to continually work on improving the effectiveness and efficiency of response efforts.

Among all the performance metrics provided in Tables 3-13 and 3-14, PG&E highlights the following five metrics as key measures of performance, which illustrates the complexity during response and compliance with the expectations outlined in GO 166 Standard 1.

1) Customer Average Interruption Duration Index (CAIDI) – Measures average outage duration per customer and is identified in Standard 12 of GO 166 to be a benchmark for the reasonableness of PG&E's response.
2) Productivity – Measured in labor hours per unit and quantifies the efficiency of the crews and resources directly supporting response in the field.
3) Straight Time, Over Time and Double Time – Measured in hours worked in each category. This is a direct component of productivity and measures performance to the established 16/8-hour work schedule used to help manage employee fatigue.
4) 911 Standby Response – Measured as a percentage of calls responded to within 60 minutes made by public safety agencies requesting response by PG&E.
5) Customers restored within 24 hours – Measured as a percentage of the total customers restored within 24 hours of the first call reporting the outage. This quantifies the efficiency of the response and directly impacts CAIDI.

TABLE 3A-3
EMERGENCY RESPONSE
EVENT LEVEL PERFORMANCE METRICS FOR 2017 AND 2019 FIRE EVENTS

	Event	2017 Tubbs Fire	2017 Laporte Fire	2017 Cherokee Fire	2019 Glencove Fire	2019 Bethel Island Fire	2019 Camino Fire
Spend	Cap $	$ 93,929,341	$ 804,469	$ 130,135	$ 199,638	$ 23,962	$ 10,169
	Exp $	$ 64,341,269	$ 60,767	$ 90,282	$ -	$ 171	$ -
	Total	**$ 158,270,610**	**$ 865,236**	**$ 220,417**	**$ 199,638**	**$ 24,132**	**$ 10,169**
	Contract	$ 98,097,649	$ 60,437	$ 29,209	$ 138,438	$ 21,816	$ 7,086
	Labor	$ 27,253,209	$ 378,679	$ 93,456	$ 18,928	$ 1,113	$ 1,414
	Materials	$ 10,417,267	$ 103,835	$ 16,797	$ 15,810	$ -	$ -
	Other	$ 22,502,486	$ 322,285	$ 80,956	$ 26,462	$ 1,203	$ 1,668
	Total	**$ 158,270,610**	**$ 865,236**	**$ 220,417**	**$ 199,638**	**$ 24,132**	**$ 10,169**
Productivity	Cap Hrs	101,407	2,445	396	9	-	3
	Exp Hrs	34,874	148	296	-	1	-
	Total Hrs	136,281	2,593	692	9	1	3
	ST HRS	70,354	1,000	307	-	-	-
	OT HRS	14,077	90	28	-	-	-
	DT HRS	51,850	1,503	357	9	1	3
	Cap HRS/Unit	28.67	46.10	46.15	1.50	-	1.50
	Exp Hrs/Unit	251.69	78.31	78.31	-	0.50	-
	Total Hrs / Unit	**37.07**	**47.21**	**55.99**	**1.50**	**0.50**	**1.00**
Units	Cap Units	3,537	53	9	6	-	2
	Exp Units	139	2	4	-	2	1
	Total Units	**3,676**	**55**	**12**	**6**	**2**	**3**
	Poles	1,219	38	6	3		1
	Conductor	1,651	6	4	2	1	2
	Transformers	224	5	1	-	-	-
	Cross Arms	71	4	1	-	-	-
	Other	512	1	1	1	1	
Outage and Customer Impact	Duration	123 Days	11 Days	8 Days	1 Day	1 Day	3 Days
	CAIDi	11,592	320	4,545	4,847	2,160	531
	3rd Party	-	-	-	1	-	-
	Animal	-	-	-	-	-	-
	Environmental /External	158	2	58	-	-	141
	Equipment Failure/ Involved	5	2	2	-	1	1
	Unknown Cause	-	-	-	-	-	-
	Vegetation	-	-	-	-	-	-
	Total Outages	163	4	60	1	1	143
	Customers Impacted	8,346	1,570	2,457	11	3,121	13,541
	% Cust Restored within 12Hrs	5.11%	93.53%	67.80%	49.94%	82.19%	49.46%
	% Cust Restored within 24Hrs	5.14%	97.61%	70.68%	99.84%	82.19%	51.10%
911 Standby	# of 911 Standby Requests	N/A	N/A	N/A	N/A	N/A	N/A
	% 911 Requests responded to within 60 mins	N/A	N/A	N/A	N/A	N/A	N/A

Tables 3-3 above shows spending, productivity and performance metrics of the fire events included in this CEMA filing. While fire events last longer and require extensive response to protect our facilities from fire damage, they have fewer outages and safety incidents such as wire down events. In addition, PG&E’s response can be significantly longer due to the dynamic changing environment associated with an active fire, as well as PG&E’s ability to gain safe access to the area as provided by the fire agency in charge, such as California Department of Forestry and Fire Protection or the United States Forest Service.

Table 3-4 shows spending, productivity and performance metrics of the 2019 storm event included in this CEMA filing. The storms from PG&E's 2018 CEMA filing are including to provide context of the 2019 Storms metric results. PG&E had a very strong safety performance, relieving 911 standby responders within 60 minutes at least 92 percent of the time during storm events (excluding the Public Safety Power Shutoff event). Doing so promotes public safety, effectively freeing up first responders to attend to other life safety calls. PG&E's reliability performance was very strong and in line with CAIDI of a non-storm day. This shows the effectiveness of PG&E's response to restore customers quickly, in line with Standard 12 of GO 166.

TABLE 3A-4
EMERGENCY RESPONSE
EVENT LEVEL PERFORMANCE METRICS FOR STORM EVENTS

	Event	2018 March Storms	2019 January February Severe Storms	2019 October Wind Event
Spend	Cap $	$ 1,017,990	$ 90,418,028	$ 9,263,277
	Exp $	$ 594,641	$ 109,326,732	$ 7,893,046
	Total	**$ 1,612,631**	**$ 199,744,760**	**$ 17,156,323**
	Contract	$ 78,672	$ 63,249,025	$ 7,076,283
	Labor	$ 690,261	$ 56,922,217	$ 4,847,056
	Materials	$ 39,532	$ 9,108,441	$ 994,536
	Other	$ 804,166	$ 70,465,077	$ 4,238,448
	Total	**$ 1,612,631**	**$ 199,744,760**	**$ 17,156,323**
Productivity	Cap Hrs	13,329	154,804	7,866
	Exp Hrs	14,405	213,845	14,311
	Total Hrs	27,734	368,649	22,177
	ST HRS	9,738	125,585	7,921
	OT HRS	1,399	14,175	375
	DT HRS	16,598	228,890	13,882
	Cap HRS/Unit	144.88	30.82	9.64
	Exp Hrs/Unit	369.36	49.43	20.86
	Total Hrs / Unit	**84.04**	**39.43**	**14.76**
Units	Cap Units	92	5,023	816
	Exp Units	39	4,326	686
	Total Units	**330**	**9,349**	**1,502**
	Poles	22	1,287	238
	Conductor	20	4,660	711
	Transformers	51	1,007	94
	Cross Arms	7	936	194
	Other	31	1,459	265
Outage and Customer Impact	Duration	3 Days	53 Days	6 Days
	CAIDi	116	352	1,050
	3rd Party	21	413	22
	Animal	25	180	19
	Environmental /External	37	258	-
	Equipment Failure/ Involved	187	2,965	128
	Unknown Cause	103	2,358	70
	Vegetation	126	4,137	62
	Total Outages	499	10,425	661
	Customers Impacted	129,009	2,370,870	185,666
	% Cust Restored within 12Hrs	98.38%	89.72%	39.22%
	% Cust Restored within 24Hrs	99.90%	95.03%	51.97%
911 Standby	# of 911 Standby Requests	137	2999	652
	% 911 Requests responded to within 60 mins	99.27%	92.20%	82.06%

PACIFIC GAS AND ELECTRIC COMPANY

2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS

CHAPTER 4

GAS

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS
CHAPTER 4
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PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS
CHAPTER 4
GAS

A. Introduction

This chapter describes the response of Pacific Gas and Electric Company's (PG&E) Gas Operations (Gas)[1] to the catastrophic events listed below.

1) 2017 Tubbs Fire;
2) 2018 Carr Fire;
3) 2019 Winter Storms; and
4) 2019 Ridgecrest Earthquakes

This chapter demonstrates the necessity and reasonableness of the steps Gas took to:

- Provide standby support to Electric Distribution;
- Eliminate potentially hazardous conditions;
- Communicate with customers;
- Repair or replace damaged gas transmission and distribution (T&D) facilities; and
- Restore gas service to customers.

The remainder of this chapter is organized as follows:

- Section B provides a summary of the financial request;
- Section C is a discussion of Gas Catastrophic Event Memorandum Account (CEMA) Events and explains the costs incurred by Gas in response to these catastrophic events; and
- Section D provides a brief conclusion.

A. Summary of Request

In response to the four catastrophic events listed above, PG&E recorded Gas expenses of $35.5 million and capital expenditures of $20.6 million. Further information is set forth in the workpapers supporting this chapter.

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[1] Both Gas Distribution and Gas Transmission (GT) incurred costs in response to the various events, included in this Application. These are referred to collectively as "Gas" or together as "Gas T&D."

Tables 4-1 and 4-2 summarize PG&E's total Gas T&D costs for the CEMA events by expense and capital before adjustments.[2] Restoration response costs are mainly focused on repairing infrastructure for customers who can receive service. The lengthier process of rebuild costs, begins later and is mainly focused on re-installing infrastructure to support permanent and temporary service and to replace destroyed infrastructure.

TABLE 4-1
CEMA EVENTS GAS EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Event	Years 2017	2018	2019	Total
1	2017 Tubbs	$19,516	$9,089	$2,648	$31,253
2	2018 Carr Fire[a]	–	–	139	139
3	2019 Winter Storms	–	–	819	819
4	2019 Ridgecrest Earthquake	–	–	3,260	3,260
5	Grand Total	$19,516	$9,089	$6,866	$35,471

(a) Costs after December 31, 2018 are included in this filing.

TABLE 4-2
CEMA EVENTS GAS CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Event	Years 2017	2018	2019	Total
1	2017 Tubbs	$4,891	$2,539	$10,425	$17,855
2	2018 Carr Fire[a]	–	–	307	307
3	2019 Winter Storms	–	–	255	255
4	2019 Ridgecrest Earthquake	–	–	2,134	2,134
5	Grand Total	$4,891	$2,539	$13,121	$20,551

(a) Costs after December 31, 2018 are included in this filing.

2 These costs do not include the adjustments made in Chapter 9, "Accounting Adjustments."

A. Discussion of CEMA Events

The following section briefly describes the impacts to PG&E's gas facilities and the activities in response to the CEMA events, including standby service that gas personnel provided to support electric service restoration.

For all emergency events PG&E gas follows standard Emergency Response processes. This includes using the Gas Emergency Response Plan, activating emergencies centers as needed, and coordinating response and restoration efforts with other lines of business and external agencies as needed. For more information on Gas emergency response processes, see Attachment A.

1. 2017 Tubbs Fire

1. Description of Event

The Tubbs Fire started began on October 8, 2017 near Highway 128 and Bennett Lane in Calistoga, Napa County. Emergency dispatchers sent fire crews to reports of downed power lines and damaged transformers.

As the California Department of Forestry and Fire Protection (CAL FIRE) and local fire departments battled the blaze, strong winds from the northeast pushed the front of the fire more than 12 miles in its first three hours. Local fire officials requested evacuations of Calistoga and Santa Rosa. On October 9, the fire was spreading quickly to the south and west and had reached Santa Rosa. By the time of its containment, it was estimated to have burned 36,807 acres in both Napa and Sonoma Counties and destroyed 5,636 structures.

2. PG&E's Response Activities

Gas activated their emergency centers, established a basecamp, coordinated with electric to assist with make-safe efforts (e.g., cutting off gas services as appropriate) and performed repair and restoration work. Gas repair and restoration efforts began on October 11, 2017. In total, 36,957 gas meters were damaged or destroyed by the Tubbs Fire. Over the course of the next few weeks, meters were restored or "cut and capped," where service could not immediately be restored due to the homes being damaged or destroyed. The table below shows a summary of the neighborhoods and work completed in 2017.

TABLE 4-3
2017 TUBBS FIRE GAS REPAIR AND RESTORATION

Line No.	Zone	Meters Restored	# Cut and Capped	Total
1	Santa Rosa (SR)-1A (Windsor)	9,281	74	9,355
2	SR-1B and SR-2B (Fulton)	6,644	2,252	8,896
3	SR-21, SR-3 and SR-4 (Santa Rosa/Oakmont)	16,856	1,850	18,706
4	Total	32,781	4,176	36,957

PG&E continued work throughout 2018 and into 2019 to restore meters and associated service as homes were repaired or rebuilt. This work consisted of pipe replacement and service restoration to homes. Pipe replacement requires trenching and digging, replacing gas distribution pipe, testing, traffic control, repairing concrete and landscaping, and all the associated equipment and labor required to do so. Service restoration requires installation of service pipe, meters, testing and relighting at the home.

PG&E incurred approximately $31 million in expense and $18 million in capital related to the Tubbs fire in CEMA-eligible counties, broken down as follows[3]:

TABLE 4-4
2017 TUBBS COST ELEMENT BREAKDOWN OF 2017-2019 EXPENSE COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	2017	2018	2019
1	Contract	$6,452	$(906)	$1,232
2	Labor	10,920	447	799
3	Materials	804	68	138
4	Other	1,339	9,479	479
5	Total	$19,516	$9,089	$2,648

3 See workpapers supporting this chapter for an additional breakdown of costs.

TABLE 4-5
2017 TUBBS COST ELEMENT BREAKDOWN OF 2017-2019 CAPITAL COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	2017	2018	2019
1	Contract	$4	$2,291	$8,660
2	Labor	2,109	529	482
3	Materials	137	305	728
4	Other	2,641	(585)	555
5	Total	$4,891	$2,539	$10,425

- The majority of Gas costs in the "contract" category relate to mutual aid (Southern California Gas Company, San Diego Gas & Electric Company), Hydro-Vac services, wet/dry spoils, hauling and backfilling, construction services (i.e., main and services installation), inspection services, traffic control, paving and grading services, and security and base camp facilitation.
- The majority of Gas costs in the "labor" category relate to Gas construction, Gas field services, engineering and estimating, paid time off and indirect overhead burdens, estimating and design, and locate and mark.
- The majority of Gas costs in the "material" category relate to pipe and conduits, elbows, fittings, freight, working stock and minor materials.
- The majority of Gas costs in the "other" category relate to benefits and payroll tax burdens, operational management and operational support overheads, facility, Information Technology (IT), and fleet overheads.

2. 2018 Carr Fire

1. Description of Event

The Carr Fire began on July 23, 2018. CAL FIRE responded to a mechanical failure of a vehicle that had ignited vegetation in the vicinity of Highway 299 and Carr Powerhouse Road, in Whiskeytown, Shasta County. As CAL FIRE battled the blaze, the wildfire grew to 20,000 acres during the overnight hours from July 25 to July 26, forcing the evacuations of Old Shasta, the town of Keswick, and all surrounding areas, and the closure of Highway 299 in Redding. The Carr Fire ultimately burned 229,651 acres, destroyed 1,604 structures, and damaged an additional 277 structures.

2. PG&E's Response Activities

PG&E crews confirmed widespread damage in the early stages of the Carr Fire. The Gas Distribution Control Center immediately began developing isolation plans to "shut in" (stop) gas service in impacted areas. Maintenance and Construction (M&C) personnel worked out of local offices to support the response effort. Ultimately, 614 gas customers lost service as a result of the isolation plans that PG&E implemented. Of these, 351 customers were restored immediately after the fire. The remaining 263 customers could not be immediately restored because their properties were either damaged or destroyed. Accordingly, their gas services were cut and capped.

In 2019 PG&E employees and contractors continued work to restore service to neighborhoods and properties as they were rebuilt. PG&E incurred approximately $0.1 million in expense and $0.3 million in capital related to the Carr Fire in 2019, broken down as follows[4]:

TABLE 4-6
2018 CARR FIRE COST ELEMENT BREAKDOWN OF 2019 EXPENSE COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	CEMA-Eligible Spending
1	Contract	$46
2	Labor	68
3	Materials	7
4	Other	18
5	Total	$139

4 See workpapers supporting this chapter for an additional breakdown of costs.

TABLE 4-7
2018 CARR FIRE COST ELEMENT BREAKDOWN OF 2019 CAPITAL COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	CEMA-Eligible Spending
1	Contract	$87
2	Labor	95
3	Materials	23
4	Other	103
5	Total	$307

- The majority of Gas costs in the “contract” category relate to traffic control, wet/dry spoils, excavation, hauling and backfilling, paving and grading services.
- The majority of Gas costs in the “labor” category relate to Gas Construction, Engineering and Estimating paid time off, and indirect overhead burdens.
- The majority of Gas costs in the “material” category relate to pipe and conduits, elbows, fittings, freight, working stock and minor materials.
- The majority of Gas costs in the “other” category relate to Benefits and Payroll tax burdens, Operational Management and Support overheads, Facility, IT, and Fleet overheads.

3. 2019 Winter Storms

1. Description of Events

Several storm events in early 2019 required Gas Emergency Center activation, field response and restoration work.

The first event was due to rain causing ground movement in Sausalito and Tiburon. On February 14, 2019, PG&E was alerted of a landslide in Sausalito that caused damage to homes and a gas leak in the area. Approximately 50 customers were evacuated. PG&E crews isolated the gas system in the area that same morning to investigate the damage. The Operation Emergency Center (OEC) was operational to support the event. Later that morning, another landslide was reported in Tiburon that caused damage to a road and the gas main in the area.

The second event was related to North Bay rain monitoring. The North Bay OEC proactively became operational on February 26, 2019 due to heavy rains and potential flooding.

The third event was related to flooding in the Russian River area. On February 27, 2019 the Sonoma OEC became operational due to current weather (significant rainfall, flooding of Russian River, etc.) having potential impact on the gas system in the Sonoma Division.

2. PG&E's Response Activities

PG&E response activities to each of the three events is described below. In Sausalito, 14 customers had gas service shut off during repairs. At the time, six of these customers had damage to their homes and gas service could not be restored. The remaining eight customers were restored once gas main repairs were completed to the gas main in the area. In Tiburon, 19 customers had gas service shut off as a result of the land movement. Due to extensive road repairs required, only 12 customers had service restored the same day. The remaining seven customers were without service until repairs were completed in the following days. The OEC was supported by 17 employees through deactivation on February 15, 2019. In the field, over 60 employees performed over 800 hours of work to complete engineering, estimating, locating, construction, pipe repair and other services.

In response to the North Bay rain monitoring, 19 employees supported the OEC. The table below shows the number of employees that were in the field to perform assessments and standby for possible repairs. On February 29, 2019 the OEC deactivated and crews were no longer needed to support as no major incidents were caused by the rain and the weather had passed though.

TABLE 4-8
NORTH BAY RAIN MONITORING STAFFING SUPPORT

Line No.	Department	# of Employees
1	M&C	3
2	Gas Operations – Operations and Maintenance	3
3	Leak Survey	7
4	Locate & Mark	5
5	Gas Service Representatives	13
6	General Construction (GC)	12

In response to the Russian River area flooding, Gas service was shut-in for 256 customers in areas with flooding and expected flooding. Two new valves were installed to facilitate shut-in activities. One new Supervisory Control and Data Acquisition (SCADA) site was installed to facilitate Gas Control monitoring of the system. Once flooding receded restoration plans were implemented beginning March 1, 2019. Five zones were established for purging and testing. Four large water pumps were rented to remove water from low lying areas. PG&E Environmental Field Specialists worked with the State Water Board to ensure water quality was monitored. The Sonoma OEC was deactivated on March 2, 2019. All customers had gas service restored by March 3, 2019. The table below shows the staffing used for emergency center support, as well as shut-in, purging and restoration activities.

TABLE 4-9
RUSSIAN RIVER AREA FLOODING STAFFING SUPPORT

Line No	Department	# of Employees
1	OEC Support	25
2	Field Services	20
3	GC	15
4	M&C	19

PG&E incurred approximately $0.8 million in expense and $0.3 million in capital related to the 2019 winter storms, broken down as follows:[5]

TABLE 4-10
2019 WINTER STORMS COST ELEMENT BREAKDOWN OF 2019 EXPENSE COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	CEMA-Eligible Spending
1	Contract	$83
2	Labor	372
3	Materials	31
4	Other	334
5	Total	$819

TABLE 4-11
2019 WINTER STORMS COST ELEMENT BREAKDOWN OF 2019 CAPITAL COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	CEMA-Eligible Spending
1	Contract	$56
2	Labor	85
3	Materials	6
4	Other	108
5	Total	$255

- The majority of Gas costs in the "contract" category relate to traffic control, Engineering and Vac Truck services, paving and grading services.
- The majority of Gas costs in the "labor" category relate to Gas Construction, Gas Field Services, paid time off, and indirect overhead burdens.
- The majority of Gas costs in the "materials" category relate to valve, pipe and conduits, working stock and minor materials.

5 See workpapers supporting this chapter for an additional breakdown of costs.

- The majority of Gas costs in the "other" category relate to trench plate rental, Benefits and Payroll tax burdens, Operational Management and Support overheads, Facility, IT, and Fleet overheads.

4. 2019 Ridgecrest Earthquakes

Multiple earthquakes in the Ridgecrest area in 2019 required Gas Emergency Center activation and response work.

1. Description of Events

On July 4, 2019, PG&E was notified of a magnitude 6.3 earthquake near the town of Ridgecrest. On July 5, PG&E was notified of a 7.1 earthquake near the town of Ridgecrest. By July 6, PG&E received 30 gas odor calls in Ridgecrest and Trona.

2. PG&E's Response Activities

The Gas Emergency Center activated to support the OEC on July 5, 2019. The Gas T&D pipelines in the Ridgecrest and Trona areas were patrolled and leak surveyed over the course of 10 days. Lines 372 and 311 were assessed for damage at fault locations. 300 feet of damaged pipe was cut out on lines 311 and 372. 353 leaks were identified in the system. Compressed Natural Gas/Liquefied Natural Gas was used to support customers while repairs were made, so no customers lost gas during this time. The OEC deactivated July 14, 2019, and the Gas Emergency Center deactivated on July 7, 2019. The table below shows the staffing used for emergency center support and field activities.

TABLE 4-12
2019 RIDGECREST EARTHQUAKES STAFFING SUPPORT

Line No.	Department	# of Employees
1	OEC support	18
2	Gas Emergency Center support	19
3	Locate and Mark	51
4	Leak Survey	260
5	M&C	371
6	GC	66
7	Field Services	221
8	Gas Transmission	243

PG&E incurred approximately $3.3 million in expense and $2.1 million in capital related to the 2019 Ridgecrest earthquakes, broken down as follows.

TABLE 4-13
2019 RIDGECREST EARTHQUAKES COST ELEMENT BREAKDOWN OF 2019 EXPENSE COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	CEMA-Eligible Spending
1	Contract	$227
2	Labor	1,481
3	Materials	315
4	Other	1,237
5	Total	$3,260

TABLE 4-14
2019 RIDGECREST EARTHQUAKES COST ELEMENT BREAKDOWN OF 2019 CAPITAL COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	CEMA-Eligible Spending
1	Contract	$479
2	Labor	690
3	Materials	246
4	Other	720
5	Total	$2,134

- The majority of Gas costs in the “contract” category relate to 300 feet on Line 372, and 300 feet on line 311 of transmission main replacement, non-destructive examination, in-line inspection, wet/dry spoils, hauling and backfilling, surveying, inspection services, paving and grading services.
- The majority of Gas costs in the “labor” category relate to Gas Construction, Gas Field Services, paid time off, and indirect overhead burdens.
- The majority of Gas costs in the “materials” category relate to pipe and conduits, elbows, fittings, freight, working stock and minor materials.
- The majority of Gas costs in the “other” category relate to employee related expenditures (meals, lodging, travel, etc.), benefits and payroll tax burdens, Operational Management and Support overheads, Facility, IT, and Fleet overheads.

B. Conclusion

This chapter describes PG&E’s Gas facilities that were damaged, Gas response activities, and standby work in response to the CEMA events outlined above. As explained herein, PG&E’s costs of restoring gas service to customers, repairing, replacing, or restoring damaged gas facilities, and complying with governmental agency orders in connection with these events are reasonable and limited to costs incurred in counties where a state of emergency were declared. Thus, recovery of these costs through CEMA should be approved.

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ADDITIONAL MATERIAL

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A. PG&E's Requested Gas Transmission & Distribution (T&D) Costs Are Eligible for Catastrophic Event Memorandum Account (CEMA) Recovery

For the 2017-2019 period, Pacific Gas and Electric Company (PG&E or the Company) Gas forecast its Gas Transmission (GT) and distribution routine emergency response budgets in the Gas Transmission and Storage (GT&S) Rate Case and the General Rate Case (GRC), respectively, based upon the trend for the normal number of units of work to perform routine emergency work. These forecasts do not include or reflect CEMA costs.

1. Routine GRC and GT&S Work

PG&E records costs associated with routine GT and distribution system emergency response expense work in various Major Work Categories (MWCs) and Maintenance Activity Types (MAT), the more common MWCs and MATs used are described below.

PG&E records costs associated with routine GT pipeline emergency response expense in MWC JT – Reliability and General Maintenance, including MAT JTB – Pipeline Safety and Reliability Pipe Replacements.[1] This work includes responding to dig-ins, leaks, and non-routine corrective maintenance. Routine GT pipeline emergency response capital work is recorded in MWC 75 – Pipeline Reliability, including MAT 75O – Other Pipeline Safety and Reliability Pipe Replacements. This work includes pipe replacement required as a result of leaks, dig-ins, or corrosion integrity issues.

PG&E records costs associated with routine gas distribution system emergency response expense in MWC FI – Corrective Maintenance, including MAT FIM – Gas Major Event and Emergencies. Activities

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[1] If GT system emergency response expense work is performed on a station asset, costs may be recorded in MWC JP – Station Maintenance, including MAT JPN – Station Operations.

associated with MWC FI include work required to repair mains and services, such as leak repair. PG&E records costs associated with routine gas distribution system emergency response capital in MWC 52 – Gas Distribution Emergency Response, including MATs 52B – Emergency Response Gas Dig-Ins, Services and 52C – Emergency Response Gas Dig-Ins, Main. Activities associated with MWC 52 include replacement of mains and services due to incidents that do not result in an emergency declaration, such as dig-ins, or small-scale natural disasters such as landslides or localized earthquakes. PG&E also records costs associated with routine gas distribution system emergency response capital in MWC 50 – Gas Distribution Reliability, including MATs 50A – Reliability Main Replacement and 50B –Reliability Service Replacement. Activities associated with MWC 50 include replacing gas distribution mains and services.

2. CEMA Gas T&D Restoration and Rebuild Work

Non-routine, major emergency work is also recorded in the above MATs. However, such non-routine, major emergency work is recorded under the specially coded and titled orders described above that allow them to be clearly and automatically segregated from routine work of the same type and then moved to the CEMA MWCs.

The CEMA mechanism allows PG&E to recover from its customers the incremental costs associated with response and restoration activities for a catastrophic CEMA event.[2] For the CEMA events described above, incremental Gas CEMA costs incurred in the declared counties are included in this application.[3] These incremental costs qualify for CEMA recovery because they were incurred only in counties where emergencies were declared.

B. PG&E's Requested Gas T&D Costs Are Reasonable

In the early stages of emergency response for the various CEMA events, Gas performed two primary tasks: it stopped the flow of gas from damaged lines

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2 See Chapter 8 which demonstrates the incrementality of costs requested in this application.

3 See workpapers supporting this chapter for additional information.

and meters, and it supported Electric Distribution with debris clean-up. Once these two primary tasks were accomplished, Gas began its own restoration procedures. These include cutting and capping damaged gas lines to those structures that cannot receive gas service and inspecting/repairing/replacing damaged meters for those customers whose structures can receive gas service.

The personnel involved in the CEMA event were requested by the OEC Incident Commander (IC) in consultation with maintenance, construction, and engineering experts in response to the need to expeditiously and safely return communities to states of relative normalcy. Generally, each cut and cap procedure takes 3 to 4 hours to safely complete. The time to excavate a gas line, to replace damaged pipe, to squeeze (close off) an existing line, or to weld components are all factors in the total time needed to complete each cut and cap. Additionally, each cut and cap operation minimally requires a 2-person crew with support from Leak Survey and Locate and Mark personnel. Generally, each Maintenance and Construction (M&C) team is able to cut and cap 2 to 3 services each day. The Gas Services Representatives and Field Services personnel are able to complete relights relatively quickly after services have been repaired by M&C. Even with personnel working 12-hour days, these processes can take weeks to safely complete in large communities.

PG&E Gas actions in response to the various CEMA events were necessary and reasonable given the extensive damage the events caused, the potential damages they threatened to cause which required standby service to support electric outages, and to prevent damage to gas facilities if the threats increased. PG&E acted responsibly to ensure the safety of the public and to restore service to customers as quickly and efficiently as possible. Therefore, PG&E's request for recovery pursuant to CEMA requirements is reasonable and should be granted by the California Public Utilities Commission.

C. Accounting for Gas Emergency Costs

During an emergency that affects gas facilities, Gas tracks the costs incurred to restore gas utility service and repair damaged facilities. The accounting process for Gas emergencies differs from the process for Electric Distribution.

Unlike Electric Distribution, Gas has not historically used MWCs that are exclusive to emergencies. Instead, Gas has historically used certain conventions to create accounting orders within existing MWCs featuring unique reason codes and titles to identify the emergency work and the county in which the work occurred. These orders are created for both capital and expense. This allows PG&E to query its accounting system to select only the emergency response work that occurred in the counties covered by a government-declared emergency for CEMA treatment. The Business Finance Department, Emergency Preparedness Coordinator, and the affected divisions review the orders to ensure that the costs identified for CEMA treatment did in fact occur within the timeframes of the CEMA event, in accordance with major CEMA event charging guidelines, and within the appropriate counties. In 2018, Gas created catastrophic event MWCs 3Q (capital) and LX (expense). While Gas catastrophic event orders will continue to originate under existing MWCs aligned with the work performed, orders will then transition to Transmission or Distribution catastrophic event MATs under MWC 3Q and LX.

D. Gas Incident and Emergency Response Process

This section defines gas incidents and emergencies and describes Pacific Gas and Electric Company's (PG&E or the Company) gas service territory, the Gas Emergency Response Plan (GERP), Gas Emergency Center (GEC) and field facilities, levels of gas incidents/emergencies and activation criteria, incident response, outage communication, and emergency cost recovery management.

1. Gas Incident/Emergency Definition

A gas incident/emergency occurs when there is:

- An actual or potential hazardous escape of gas;
- An over pressure or under pressure situation; or
- An interruption of gas supply.

2. Scope of PG&E Gas Facilities Exposed to Potential Emergency Conditions

PG&E's Gas Operations is divided into transmission, storage, and distribution operations. The transmission system includes backbone pipelines that transport gas from interstate pipelines connected to natural gas basins in western North America, including western Canada, the United States Southwest, and the Rocky Mountains.

Local gas transmission lines transport gas from the backbone to the distribution system. They also move gas into and out of underground natural gas storage fields. Gas also maintains Compressed Natural Gas (CNG)/Liquefied Natural Gas (LNG) injection capabilities to support local T&D disruptions.

To manage gas distribution, PG&E has divided its gas service territory into two regions and 18 divisions. Similarly, to manage gas transmission, it has established 13 districts. Resources are typically assigned to one region, division, area, or district, but can be moved within and across boundaries as required for incident response.

Gas Operations is managed from the Gas Operations Center in San Ramon. The Gas Operations Center is comprised of Gas Dispatch and Scheduling, the Gas Transmission and Distribution Control Center. Each division and district has local engineering resources to coordinate with the GEC in the event of an incident/emergency.

3. Gas Emergency Response Plan

The GERP is the Gas functional annex to the Company Emergency Response Plan (CERP).

The GERP provides detailed information about PG&E's planned response to T&D incidents/emergencies. GERP guidance is consistent with the Incident Command System (ICS). The ICS is a standardized, all-hazard incident management system that provides a systematic, proactive approach for the government, nongovernmental organizations, and the private sector to work together in an incident, in order to reduce the loss of life and property and harm to the environment. The ICS is based on proven management principles, implemented through a wide range of management features including the use of common terminology, clear text, and a modular organizational structure.

The GERP incorporates industry best practices, standards, requirements, regulations, and laws into its emergency response protocols. The GERP supports responding to all incidents/emergencies as "One PG&E" through integration with the CERP and the other lines of business (e.g., Electric Operations). The GERP identifies the relationship between gas emergency response and other company-wide planning efforts, such as Business Continuity and Community Recovery processes.

4. Incident Levels and Activation Criteria

PG&E uses a five-level system to manage gas incidents/emergencies, see Table 1 below.

TABLE 4A-1
FIVE-LEVEL SYSTEM MANAGING GAS INCIDENTS/EMERGENCIES

Level	Label	Description
1	Routine	Involves a relatively small number of customers, such as those managed during routine operations. Local resources are the preferred response. Does not require the activation of an Operations Emergency Center (OEC).
2	Elevated	Requires more than routine response. Resources are mainly local, but there is a possibility that resources may need to move within the Region/Area. An OEC may be activated with Command and General Staff. Full OEC activation is possible.
3	Serious	Involves a large number of customers. Resources primarily move within the Region/Area but may need to move between Regions/Areas. One or more OEC(s) may activate. The GEC and/or the Emergency Operation Center (EOC) may activate.
4	Severe	Involves an escalating incident with Company impact or extended multiple emergency incidents that impact a large number of customers. Resources are brought in from outside the division, district, area and/or region. Gas Construction and contractor resources are mobilized across regions. The OEC(s), GEC and EOC are activated.
5	Catastrophic	Involves multiple incidents, impacts a large number of customers, has a significant cost, and results in significant infrastructure risk/damage. Emergency affects the ability to conduct business operations. Full mobilization of company resources is needed to respond, and mutual aid is needed. The OEC, GEC, and EOC are activated.

PG&E's Incident Level system allows PG&E to quickly and decisively understand the actions that should be taken. Determining the incident level includes identifying actual and potential customer outages (since responses to gas incidents involve considerations of peak capability), possible non-core customer curtailments, gas system back-feeding options, and the use of LNG/CNG. A primary focus of gas response is dedicated to prevention of gas service interruption, with restoration being the secondary focus.

5. Gas Emergency Centers (OEC, GEC, EOC) and Field Facilities

Emergency Centers and field facilities are important parts of PG&E's emergency response. Depending on the level of the incident, command and control may be executed an any one of PG&E's designated emergency centers.

a. Operations Emergency Center

OEC staff provide oversight and support at the division and/or district level. OEC staff is composed of personnel called from a divisional roster in response to an incident. 18 teams are available for OEC duty and may be called, as needed. The OEC is activated by Gas Emergency personnel with authority to activate. Once formed in response to an incident, an OEC directs and coordinates the personnel necessary to assess damage, make safe, restore service, and communicate status information internally and externally. OECs may support more than one incident at a time, and may have several Incident Command Posts (ICP) reporting to them.

b. Gas Emergency Center

The GEC, located within the Gas Operations Center in San Ramon, is staffed by an Incident Support Team/GEC Team that activates in support of gas-only incidents or the gas aspects of dual commodity (gas and electric) events when the EOC has been activated for dual commodity events. Five teams are available for GEC duty and serve on a two-week rotational basis. The GEC is activated by Gas Emergency personnel with authority to activate. During dual commodity events, the GEC may support the EOC in Operations, Planning and Intelligence, Logistics, Finance and Administration, Safety, Public Information Office duties, Liaison duties, and Customer Strategy. During an EOC activation, the GEC reports to the Operations Branch in the EOC. If the EOC is not activated, the GEC manages the overall gas incident.

c. Emergency Operations Center

The EOC is a designated location where information and resources are coordinated to support incident management activities. EOC activation occurs for Level 4 or 5 incidents, or during a Level 3 incident when deemed necessary by the IC and/or the Director of Emergency Preparedness and Response.

When the EOC is activated, the EOC Commander establishes priorities for the incident and supports the emergency centers and field responders. During significant emergency incidents, PG&E may activate additional emergency centers to support the primary EOC activities. These emergency centers manage the work in a defined geographic region. They are responsible for directing resources to implement actions and for reporting status and progress through the emergency center chain of command ultimately to the EOC.

d. Incident Command Post

At the scene of a Level 1 incident, activities of on-scene response personnel are typically managed at a gas ICP location. The IC or delegate serves as the single point of contact for all off-site (e.g., Gas Control Center) and other PG&E (e.g., Company Communications) groups.

e. Mobile Command Vehicle

A Mobile Command Vehicle (MCV) is a specialized vehicle that can be deployed to and stationed at the scene of an incident. The MCV can act as an ICP or an emergency center, if warranted. MCVs help facilitate communication between response crews, command staff, and government agencies. There are three types of MCVs available at the Company: Type I Commander (motor coach), Type III Sprinter (van), and Emergency Communications Trailer. MCVs are specially outfitted for events that may require multiple personnel to be stationed near the site of an incident for one or more days.

f. District Storm Room

A District Storm Room (DSR) is primarily an electric asset whose main function is to manage the local restoration effort during all levels of incidents. The DSR is generally located in a Service Planning and Maintenance yard. DSR staff is composed of corresponding positions found in the OEC, as well as local support, such as gas service representatives, estimators, mappers, and M&C crews.

6. Key Response Steps

PG&E uses the ICS structure, which is a systematic tool used for the command, control, and coordination of incident/emergency response, to complete key steps in the incident response. The ICS involves a structured response to:

1) Establish command;
2) Assess the situation;
3) Take “Make Safe” actions;
4) Communicate with and notify all necessary parties, including first responders, government agencies, and customers (ongoing);
5) Restore service; and
6) Recover/Demobilize.

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CHAPTER 5

POWER GENERATION

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POWER GENERATION

A. Introduction

This chapter describes certain costs for Pacific Gas and Electric Company's (PG&E) Power Generation facilities that were recorded during 2011-2019 in three memorandum accounts. Those accounts are:

- Catastrophic Events Memorandum Account (CEMA),
- Wildfire Mitigation Plan Memorandum Account (WMPMA); and
- Land Conservation Plan Implementation Account (LCPIA).

With respect to the CEMA costs, this chapter demonstrates the necessity and reasonableness of the steps PG&E took to rebuild and restore to service the Power Generation Facilities damaged during 2019 January-February Storm event. PG&E's response to this event was coordinated and managed so that the Power Generation facilities could be restored as quickly and efficiently as possible. The steps PG&E took were necessary and reasonable to eliminate potentially hazardous conditions and rebuild or replace damaged facilities and restore to service PG&E's flexible and clean source of hydroelectric energy.

With respect to the WMPMA costs, this chapter demonstrates the significant and continued effects of fire threat in California, the incremental activities PG&E took to mitigate those effects on its facilities, and the reasonableness of those activities.

With respect to the LCPIA costs, this chapter demonstrates the necessity and reasonableness of the steps PG&E took to implement the Land Conservation Plan approved by the California Public Utilities Commission (CPUC or Commission) in Decision (D.) 03-12-035.

B. Summary of Request

PG&E recorded Power Generation (PGEN) expenses of $3.0 million and capital expenditures of $3.2 million as shown in Table 5-1 below.

TABLE 5-1
POWER GENERATION SUMMARY OF COSTS
(THOUSANDS OF DOLLARS)

Line No.	Accounts	Expense	Capital
1	CEMA – 2019 Jan/Feb Severe Storm	$697	$3,215
2	WMPMA	2,213	–
3	LCPIA	77	–
4	Total	$2,986	$3,215

C. Costs by Account

1. CEMA

Power Generation forecasts its routine emergency and maintenance costs in the General Rate Case (GRC), based upon the trend for the normal routine emergency work. These forecasts do not include or reflect CEMA costs incurred during or following any major storm or fire event. CEMA allows PG&E to recover the incremental costs associated with response and restoration activities for a catastrophic event from its ratepayers.

Costs for routine operations, maintenance, and compliance for PG&E's hydro generation facilities are primarily based upon labor and other recurring costs and are typically consistent year over year. The costs of the individual projects included in the Hydro forecast are estimated on a project-specific basis. PG&E's forecast is based on a bottoms-up calculation of the expected costs for the projects and programs to be implemented in the forecast year.

In contrast, recorded costs for CEMA are based on actual dollars spent on rebuilding or restoring the existing facilities damaged due to fire or storm event. These costs are tracked and accounted for separately from the routine operation and are not recovered from the GRC.

The following CEMA event affected PGEN facilities: 2019 January/February storm. On February 21, 2019, Governor Newsom proclaimed a State of Emergency due to the 2019 Winter Storms. This proclamation would ultimately cover the following counties: Amador, Glenn, Lake, Sonoma, Calaveras, El Dorado, Humboldt, Los Angeles, Marin, Mendocino, Modoc, Mono, Monterey, Orange, Riverside, San Bernardino, San Diego, San Mateo, Santa Barbara, Santa Clara, Shasta, Tehama, Trinity, Ventura, and Yolo Counties (the Counties). These storms began on January 5, 2019 and brought high winds, substantial precipitation, and flooding as the atmospheric river swept through California.

PG&E incurred the following costs responding to these storms related to Power Generation facilities: $0.7 million expense and $3.2 million capital. See Tables 5-2 and 5-3 for a breakdown of these costs.

TABLE 5-2
2019 JANUARY-FEBRUARY STORM COST ELEMENT BREAKDOWN OF 2019 EXPENSE COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	2019
1	Contract	$131
2	Labor	531
3	Materials	32
4	Other	3
5	Total	$697

TABLE 5-3
2019 JANUARY-FEBRUARY STORM COST ELEMENT BREAKDOWN OF 2019 CAPITAL COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	2019
1	Contract	$1,960
2	Labor	537
3	Materials	55
4	Other	662
5	Total	$3,215

a. Damaged Facilities

The facilities damaged during the 2019 January and February storm includes River Road, Mill Creek Crossing and Tiger Creek Road area in Amador County near Highway 88.

There was significant damage along a 2.3-mile section of the River Road. In some cases, the road section was completely gone. Subsequent to these storm events on February 14, 2019, multiple sections along River Road from Tiger Creek Road to the Tiger Creek Afterbay Dam suffered substantial damages that required reinforcement using rock rip-rap revetment installations.

Examples of the damage are shown in Figures 5-1 and 5-2 below.

FIGURE 5-1
EXAMPLES OF DAMAGE AT MULTIPLE LOCATIONS ALONG RIVER ROAD

The Storm washed out Mill Creek Crossing/Tiger Creek Road resulting in zero access to and from Tiger Creek Powerhouse. There were multiple sections along Tiger Creek Road from Tiger Creek

Powerhouse to the regulator bridge that suffered substantial damage that needed reinforcement using rock rip-rap revetment installations. Also, to reestablish the powerhouse access, replacement of the culvert (bridge) was essential.

FIGURE 5-2
EXAMPLES OF DAMAGE AT MULTIPLE LOCATIONS ALONG TIGER CREEK ROAD

b. Restoration Activities

The River Road section from Tiger Creek Road to Tiger Creek Afterbay, approximately 1/2 mile long, was restored and reinforced at multiple locations using rock rip-rap revetments to restore safe and reliable access.

The scope of work for the 2019 January-February Storm damage at the Tiger Creek facility included multiple rip-rap revetments on Tiger Creek Road (Hwy 88 to Mill Creek) including all restoration efforts at the Mill Creek crossing which included installation of a reinforced steel culvert (8-foot diameter corrugated metal pipe), road pavement surface replacement (replacement required since this section completely washed away). The last section of road along multiple sections, Tiger Creek Road from Tiger Creek Powerhouse to Regulator reservoir required rock rip-rap revetments including base rock to restore safe and reliable access to hydro the features, including public safe access.

2. Wildfire Mitigation Plan Memorandum Account

In 2019, PG&E performed defensible space vegetation removal work around more than 290 substations and hydro assets for creating defensible space. The objective around the defensible space work was to create a "clean zone" where no vegetation was present within 30 feet of energized equipment and one hundred foot "reduced fuel zone" where vegetation was thinned and spaced. By creating defensible space around its assets, PG&E addressed a key component in mitigating wildfire risk for not only the equipment at a facility, but also for private property damage associated with a fast-moving wildfire near a PG&E facility. With a defensible space plan for each site, PG&E removed vegetation that grew uncontrolled low to the ground (brush), maintained increased tree canopy spacing by reducing tree inventory, and treated new or regrown vegetation. These efforts have reduced potential wildfire fuel and created defensible space for improved protection of facilities and private properties. An example of this work is shown in Figures 5-3 and 5-4. Figure 5-3 shows the area around PG&E's Rock Creek Powerhouse switchyard before the defensible space work was implemented while Figure 5-4 shows the area around the switchyard after the defensible space work was implemented.

PG&E spent $2.2 million in expense costs for this work to address public safety. See Table 5-4.

TABLE 5-4
DEFENSIBLE SPACE VEGETATION REMOVAL WORK COST ELEMENT BREAKDOWN OF 2019 EXPENSE COSTS
(THOUSANDS OF DOLLARS)

Line No.	Cost Category	2019
1	Contract	$2,065
2	Labor	148
3	Materials	0
4	Other	(1)
5	Total	$2,213

FIGURE 5-3
ROCK CREEK POWERHOUSE SWITCHYARD BEFORE THE DEFENSIBLE SPACE WORK

FIGURE 5-4
ROCK CREEK POWERHOUSE SWITCHYARD AFTER THE DEFENSIBLE SPACE WORK

3. Land Conservation Plan Implementation Account

The purpose of the LCPIA is to record, for subsequent recovery from customers, a portion of the costs incurred by PG&E to process applications presented before the CPUC or the Federal Energy Regulatory Commission (FERC) on transactions necessary to implement the Land Conservation Plan approved by the CPUC in D.03-12-035.[1] These are external regulatory-related costs (and other costs not included in the GRC) associated with implementing the Land Conservation Commitment.

In the future, this account will also track the cost to implement FERC actions to comply with the National Environmental Policy Act and CPUC actions to comply with the California Environmental Quality Act. These costs are not funded through the GRC.

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[1] CPUC Resolution E-4072, dated May 3, 2007, approved PG&E Advice Letter 2954-E.

PG&E is requesting $0.077 million ($0.081 million with interest) in compliance costs for LCPIA incurred from 2011-2019 as shown in Table 5-2 below.

TABLE 5-5
LEGAL COMPLIANCE COST FOR LCPIA
(THOUSANDS OF DOLLARS)

Line No.	Description	2011	2012	2013	2014	2015	2016	2017	2018	2019	Inception-to-Date
1	Cost Incurred	$5.8	$5.3	$24.2	$18.7	$6.8	$1.6	$5.3	$6.6	$2.4	$76.8
2	Interest Accrued	–	–	–	–	0.1	0.3	0.7	1.5	1.8	4.4
3	Total Expense	$5.9	$5.3	$24.2	$18.8	$6.9	$1.9	$6.0	$8.1	$4.2	$81.2

As mentioned above, these are external regulatory-related costs. Examples of these costs include outside counsel providing legal advice to PG&E regarding the development of Advice Filings and how the California Environmental Quality Act applies to implementation of Land Conservation Commitment transactions.

D. Accounting for Power Generation Emergency Costs

In instances when declaration of disaster has been made by a competent state or federal authority, PGEN tracks related costs incurred within the designated geographic area(s) for potential recovery by assigning Reason Code 63, Catastrophic Event, to planning orders/orders. These orders are created for both capital and expense. This allows PG&E to query its accounting system to select only the emergency response work that occurred in the counties covered by a government-declared emergency for CEMA treatment.

WMPMA costs are tracked using separate planning orders with a unique Organization Function to separate cost. Only the cost that are incurred incremental to regular vegetation management to create a defensible safe zone around PGEN assets are accounted in this memo account.

LCPIA costs are tracked in the system using receiver cost center in PGEN. The costs incurred by the CPUC and reimbursed by PG&E to process the applications related to implementation of the Land Conservation Plan.

E. Conclusion

The incremental recorded activities described in this chapter were necessary to mitigate the effects of fire and storm related emergencies, to reduce the likelihood and impact of fires on PG&E's facilities, and to implement the Land Conservation Plan. The costs incurred performing those activities were reasonable, and the Commission should authorize PG&E to recover them in this application.

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CHAPTER 6

INFORMATION TECHNOLOGY COSTS

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INFORMATION TECHNOLOGY COSTS

A. Introduction

The purpose of this chapter is to describe and request authorization to recover incremental costs incurred in 2019 for the Information Technology (IT) initiatives Pacific Gas and Electric Company (PG&E or the Company) has undertaken in support of our 2019 Wildfire Mitigation Plan (WMP). These key initiatives include the development and implementation of tools and technologies that enabled various Electric Distribution wildfire risk mitigations and controls outlined in the 2019 WMP.[1] For purposes of this chapter, these initiatives have been grouped into four categories based upon the primary Electric Distribution mitigation program area they support: (1) the IT Public Safety Power Shutoff (PSPS) Program; (2) the IT Wildfire Safety Inspection Program (WSIP); (3) the IT Asset Risk Program; and (4) the IT Vegetation Management (VM) Program.

The IT PSPS Program consisted of technology projects focused on delivering technology solutions in support of Electric Distribution's PSPS, Situational Awareness, and Safety and Infrastructure Protection Team (SIPT) mitigation strategies. These projects supported the implementation of interdependent applications that enabled PSPS business processes, including risk identification, planned event scoping, data sharing with external agencies, post-event field inspection, and real-time intelligence and reporting. These applications also supplied core data for customer notifications.

The IT WSIP Program consisted of a broad set of technology projects that enabled mitigations related to Electric Distribution asset patrols and inspections. These projects ranged from setting up the infrastructure and tools needed to support the Incident Command structure, to onboarding and equipping inspectors with mobile devices, to the implementation of the Sherlock technology solution to support the asset inspection process.

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[1] The relevant Electric Distribution mitigation initiatives are discussed in Chapter 2.

The IT Asset Risk Program, which supported Electric Distribution's System Hardening activities, consisted of technology projects that better informed asset inspection processes by leveraging data and analytics use cases to identify assets of highest risk.

The IT VM Program, which supported Electric Distribution's Incremental VM activities, consisted of technology projects that used data and analytics to better inform VM processes. The IT VM Program also entailed providing field crews supporting Incremental VM activities with ruggedized mobile devices.

Each program is described in additional detail in the sections that follow.

B. Summary of Request

TABLE 6-1
2019 RECORDED ADJUSTED IT COSTS
(THOUSANDS OF DOLLARS)

Line No.	MWC	MWC Description	Capital	Expense
1	2F	Build IT Applications and Infrastructure	$17,643	–
2	IG	Manage Various Balancing Account Processes	–	$5,900
3		Total	$17,643	$5,900

PG&E requests authorization to recover the following amounts in IT costs: $17.7 million in capital and $5.9 million in expense for wildfire mitigation costs recorded to the Fire Risk Mitigation Memorandum Account (FRMMA) in 2019. These costs are recorded in IT's organizational budget under Major Work Category (MWC) 2F for capital expenditures and MWC IG for expense. The sections that follow describe the IT spend in support of Electric Distribution's wildfire mitigation strategy as outlined in the 2019 WMP. In compliance with the terms of the FRMMA, this application only seeks recovery of IT costs incurred in the 2019 fiscal year. Descriptions of work performed in 2018 and 2020 are provided only for context.

C. IT Costs by Program Area

TABLE 6-2
2019 BREAKDOWN OF IT COSTS
(THOUSANDS OF DOLLARS)

Line No.	Program Area	Capital	Expense
1	IT PSPS Program	$8,746	$1,962
2	IT Wildfire Safety Inspection Program	5,888	3,559
3	IT Asset Risk Program	2,739	336
4	IT VM Program	269	44
5	Total	$17,643	$5,900

As illustrated in Table 6-2, IT has organized the remainder of this chapter into four main program areas. Although the costs relevant to this chapter were recorded to the FRMMA in 2019, the programs are all iterative by design and allow for further development of enhanced technology solutions using Electric Distribution field crew experiences and other user feedback. This scalability allows the implemented mitigations to provide value over time and stay current with user requirements. These and other program qualities are discussed further in the subsections below.

a. IT PSPS Program

This program category includes five types of major initiatives, as reflected in the table below.

TABLE 6-3
2019 IT PSPS PROGRAM
(THOUSANDS OF DOLLARS)

Line No.	Major Initiatives	Capital	Expense
1	Wildfire Situational Awareness	$5,887	$890
2	PSPS Field Inspection Application	1,633	221
3	Customer Technology Enhancements	1,115	690
4	Miscellaneous Small Technology Solutions	110	162
5	Total	$8,746	$1,962

These initiatives are discussed in turn in the subsections that follow.

1) Wildfire Situational Awareness

The Wildfire Situational Awareness initiative focuses on creating an integrated suite of products and services designed to better prepare us to respond to PSPS events. The initiative began in early 2018 and remains an ongoing effort. In 2019, the products and services delivered as part of the initiative allowed PG&E to scope the impact of PSPS events, identify affected customers, share data internally and externally, and track wildfire incidents, among other benefits.

In 2019, the initiative was coordinated, facilitated, and implemented by several departments across PG&E's IT organization, including IT supervised staff augmentation resources and vendor services support. In addition to the integrated IT team, developing these products and services required ongoing collaboration with the Electric Distribution organization. The key IT departments responsible for this integrated effort with Electric Distribution in 2019 included the Wildfire team, who supported frontline efforts for PSPS preparation and wildfire mitigation planning, and the Geographic Information System (GIS) Center of Excellence (CoE), who were primary custodians of the development, optimization, and maintenance of PG&E's GIS platform and front-end software application.[2] In addition, the External Data Sharing Platform team preserved the stability and quality of data sharing capabilities with internal and external partners, and the Outage Management Tool/Distribution Management System (OMT/DMS) team directly interfaced with and supported critical distribution and outage management systems for Electric Distribution. The Foundational Infrastructure and Security teams also supported the project by ensuring there was sufficient capacity and adequate security controls in place to maintain the front-end capabilities provided by the other teams.

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2 The GIS platform provides specialized software and infrastructure that enables geographic-location-related and mapping capabilities within PG&E applications.

Like most of the IT PSPS Program activities, the Wildfire Situational Awareness initiative started as an integrated model in 2018 and was differentiated after a major version of the toolset (Product or Version 1.0) was operationalized. The products and services developed as part of the Wildfire Situational Awareness initiative were foundational elements that were initially built as a dependent toolset, and later differentiated based on future projected use cases for features of the specific product or service. The key products and services (toolset) delivered by the Wildfire Situational Awareness program in 2019 are as follows: the PSPS Viewer, the Wildfire Incident Viewer (WIV) and SIPT Viewer, External Data Sharing on Enterprise Secure File Transfer (ESFT), and Notifications for Estimated Time of Restoration (ETOR) and Restorations from OMT/DMS.

These products and services are described in further detail below.

PSPS Viewer: Developed on PG&E's GeoMart platform,[3] this tool enabled PG&E to scope the impact of each PSPS event on Electric Distribution assets using asset information in PG&E's geospatial data repository. This tool also provided the resulting products that allowed PG&E to identify customers impacted, use a payload (which is an enhanced message derived from customer location) to drive notification of customers, and share a set of maps externally and internally.

WIV/SIPT Viewer: The WIV/SIPT Viewer, which was developed based on structural elements of the PSPS Viewer, integrates into the PSPS process. This viewer leverages the PSPS Viewer function to enable tracking of active wildfire incidents and their impact on PG&E infrastructure, and to support PSPS field

[3] GeoMart is an enterprise platform offering comprehensive services that focus on agility, scalability, distributed data access, and centralized content. It specifically provides access into PG&E's geospatial data repository and allows users to drill down into user-based data. In addition, it provides access to a set of geospatial toolkits that are developed in-house to facilitate rapid application development. Finally, it delivers geospatial analysis and capability for real-time insights into large datasets.

observations. As discussed in the PSPS section of Chapter 2, PSPS field observations inform decisions to both shut-off and restore service.

Following the initial development and deployment of both the PSPS and WIV/SIPT viewers, version 2.0 has been split into separate efforts for further development of the PSPS and WIV/SIPT Viewers that will run independently from the primary model, but are still a part of the complete toolset. PG&E expects to complete version 2.0 in 2020, and is already planning for a version 3.0 that will further extend the functionality of the toolset.

External Data Sharing on ESFT: This tool was created to strengthen PG&E's data sharing and communication capabilities with government entities prior to, during, and after a PSPS event. PG&E configured and automated the ESFT data sharing platform to share publishing files from the PSPS Viewer with government agencies.

Notifications for ETOR and Restorations from OMT/DMS: PG&E developed a notification process to enable the Outage Management Tool/Distribution Management System to share infrastructure and code with the PSPS Viewer.

As discussed above, most of the Wildfire Situational Awareness Initiatives were developed and supported in active partnership between IT and business teams at PG&E facilities, IT staff augmentation both at onsite and offsite locations, and our offshore managed service vendor support.

2) PSPS Field Inspection Application

PG&E started the PSPS Field Inspection Application (PSPS Inspect) initiative with the goal of providing an inspection and patrol tool for Field Operators to use during PSPS patrols. Once developed, PSPS Inspect will combine map/navigation features, PG&E asset information, field intelligence, workflow, and work forms to provide a digital tool field operations personnel can use to execute PSPS patrols, document damage or hazards associated with PG&E assets, and initiate work to restore power to customers.

PSPS Inspect has two components: (1) the Inspect Application, which is a software application that runs on iOS mobile devices such as iPhones and iPads; and (2) the Engage Web Application, which is a work order assignment, management, and reporting tool used by Task Force or Segment Leads that runs on a Google Chrome web browser.

In 2019, the PSPS Inspect product team focused on providing users the ability to document damage, hazard, and near-miss events identified during PSPS patrol and to submit a digital Electric Corrective (EC) notification form to start the restoration process.

PSPS Inspect is still being developed for use in PSPS Patrols and was released to field users in September 2020. Specific features released or being developed for release in 2020 include:

- User authentication and log-in
- Map view and user interface
- Integration with GIS Layers to display asset information
- Development of a Damage/Hazard/Near-Miss Form
- EC Create Form
- Hosting the Damage/Hazard/Near-miss Form Report in the Engage Web Application
- Photo Viewer app to display photos attached to each Damage/Hazard/Near-Miss Form

Additional features are planned to be deployed in 2021. These include the following:

- Integration of PSPS circuit segmentation as work order
- Ability to assign work orders
- Ability to document and track patrol progress
- User Profile for role and access management
- Ability to access the Engage Web Application on iPad

As with other programs, the development effort was comprised of various PG&E IT and Electric Operations (EO) departments that specialize in field inspections and mobile technology solutions. The IT Digital Catalyst team designed, developed, and continues to support this product.

3) Customer Technology Enhancements

As a direct result of the PSPS events in 2018 and 2019, PG&E's IT organization implemented a number of changes to their customer-facing systems to address customer impact. The main areas of focus were as follows: (1) Billing Operations Automation for Emergency Events; (2) PGE.com Portal Enhancements; and (3) Customer Care and Billing (CC&B) Enhancements. PG&E completed enhancements to all three areas by December 2019. These enhancements are described in further detail below.

Billing Operations Automation for Emergency Events: This initiative focused on changes to the billing process and the automation of billing operations activities to help ensure customer protections (e.g. delayed collections and debt forgiveness) were implemented for those impacted by emergencies. These efforts were supported by PG&E's IT Requirements and Design team.

PGE.com Portal Enhancements: To resolve issues faced by some customers attempting to use the PGE.com Portal during PSPS events, PG&E implemented a content delivery network (CDN) and enhanced the customer address look-up function.

During the October 8, 2019 PSPS event, PGE.com experienced significant performance issues which caused some customers to experience longer wait times or to see a "site not found" error message. PGE.com was overwhelmed by the number of requests to the website. Due to this event, PG&E partnered with one of the world's largest content distribution networks to implement a CDN to reduce the load from its system and offer a faster, higher quality user experience. CDN is a large network of servers that accelerates the delivery of website content by leveraging a geographically distributed network of specialized servers.

During other PSPS events, some users were unable to find their addresses using the address lookup function on PGE.com. Prior to October 2019, this function was internally hosted by an external vendor. The PG&E IT Customer Web team, guided by PG&E's

Customer Care Digital Strategies department and the Weather team, partnered with three external vendors to fix the issue.

Customer Care and Billing Enhancements: The CC&B enhancements supported changes in the customer information system for customers impacted by PSPS events, including requests to update customer data, postpone credit review, and/or hold billing for impacted customers. PG&E also enhanced the interface between CC&B and GeoMart by adding customer data fields. These efforts were supported by PG&E's IT Requirements and Design team in conjunction with input received from the Customer Care Operations team.

4) Miscellaneous Small Technology Solutions

PG&E developed and deployed the Maps Plus for Emergency Management (Maps+) product to provide field personnel with current information during emergencies, allowing them to perform work more safely and efficiently. PG&E developed the Maps+ solution as a technology to be used by all field employees relying on GIS functionality to conduct field work. However, as a result of the 2019 WMP, we prioritized deployment to Electric Distribution field employees and contractors and deployed to those personnel in February 2019.

The specific capabilities delivered in this project enabled updated view-only GIS emergency mode layers (i.e., fire tiering zones, active fires, basecamps, electric outages), circuit tracing capability, and limited customer information in the Maps+ mobile application for field employees and contractors. This product allowed crews to access specific locations and complete time-sensitive work within expected time frames. The team that collaborated to deliver the Maps+ project was comprised of personnel from several PG&E IT departments including Digital Catalyst, GIS CoE, Infrastructure & Operations, and Cybersecurity.

This initiative also includes some other, smaller improvements supporting PSPS systems such as management of PSPS outages in operational systems (e.g. Distribution Management System), the enablement of the SIPT team with field mobility solutions, an assessment of the meteorology system architecture and the initiation of work on PSPS data and analytics capabilities.

b. IT Wildfire Safety Inspection Program

This program category includes six types of major initiatives, as reflected in the table below.

TABLE 6-4
2019 IT WILDFIRE SAFETY INSPECTION PROGRAM
(THOUSANDS OF DOLLARS)

Line No.	Major Initiatives	Capital	Expense
1	Wildfire General IT Services & Infrastructure	$1,225	$2,505
2	Sherlock Tool	1,736	270
3	Enterprise Estimating Solution (EES) Fire Functional Upgrade	1,783	133
4	Pronto Forms	836	154
5	Transmission Support Structures	209	13
6	Miscellaneous Small Technology Solutions	100	484
7	Total	$5,888	$3,559

These initiatives are discussed in turn in the subsections that follow.

1) Wildfire General IT Services and Infrastructure

In order to immediately address the need for improved internal and external communications and data access as evidenced by the 2019 WMP, PG&E focused accelerated reliability and capability upgrades in network and communications infrastructure and deployed specific client devices such as laptop computers, ruggedized field devices and smartphones, to support data analytics and communications for field crews. This initiative consisted of the following major areas of improvement: (1) network and telecommunications expansion at the San Ramon Valley Conference Center (SRVCC); (2) network and telecommunications enablement and expansion at targeted basecamps and microsites across PG&E’s service territory; (3) accelerated procurement and deployment of both specialized and standard client devices; and (4) continuous onsite and offsite technology support, which included onboarding for new field resources and required training on client devices. These initiatives are discussed in greater detail below.

Network and Telecommunications Expansion at SRVCC: The primary purpose of rolling out expanded network capabilities at various rooms at SRVCC was to accommodate Drone Inspection Review Team/Centralized Inspection Review Team (DIRT/CIRT) resources looking at transmission, distribution, and substation inspection imagery data coming in from the field. The analysts onsite at SRVCC needed higher bandwidth to be able to quickly analyze the manual and drone inspection images and videos coming in from the field. To address this need, PG&E teams in IT and Corporate Real Estate Strategy and Services worked with trusted third-party resources to run dedicated fiber lines to the facility and perform cabling work that would allow for large numbers of people to work on image analysis simultaneously in close proximity. PG&E also enhanced the WiFi connections at SRVCC to allow for simultaneous onboarding of WSIP support personnel and inspectors at a single location. These network and communication improvements were executed multiple times between January and June of 2019 as the demand for onsite inspectors increased.

Network and Telecommunications Enablement and Expansion at Basecamps and Microsites: In addition to network and communication improvements to SRVCC, PG&E upgraded specific basecamps and microsites across our transmission and distribution inspection territory to allow for better field work coordination and efficiency. Microwave and cellular connectivity were provided at the different sites, and essential client devices such as laptops and printers were procured and deployed to field personnel. Following the initial infrastructure implementation, these sites were used to manage repair work directly in the regions, reducing the need to dispatch teams from central regions. IT telecommunications and computing teams (telecommunication technicians, computing field analysts, and project managers) led the efforts to stand up these new sites for repair work from November 2018 to July 2019.

Accelerated Procurement and Deployment of Client Devices: Procurement and deployment of client devices was not limited to the targeted basecamps and microsites. Onsite inspectors at SRVCC were also individually outfitted with refurbished laptops and peripheral devices (i.e., keyboards, mice, and printers) necessary to access and analyze data. In addition to standard client devices, PG&E purchased large high-definition monitors for onsite DIRT/CIRT team inspectors at SRVCC to allow for improved quality and easier visualization and analysis of imagery. PG&E also purchased thousands of iOS devices (iPhones and iPads) as well as mobile battery chargers, rugged cases, and mobile printers for use by field inspectors. These client devices were procured, deployed, and tracked by the Mobile Platform Services, Mobile Operations, WSIP, and Telecommunications and Computing IT teams from November 2018 to July 2019.

Continuous Onsite Technology Support: During the telecommunications, network, and client device expansion and deployment, the IT organization provided general technical support to all impacted field resources. This consisted of onsite resource onboarding (primarily at SRVCC), client device training, and any associated mobile software application training. As a result of the network expansion at SRVCC and an increase in necessary mobile equipment, multiple large inspector onboarding classes were held weekly onsite at SRVCC. In addition to facilitating the classes and training inspectors on their mobile devices, the IT team provided daily general support at SRVCC from November 2018 to August 2019. Thereafter, a smaller version of the team (consisting primarily of telecommunication technicians and computing field analysts) remained onsite to continue to provide support.

2) Sherlock Tool

Following the catastrophic California wildfires in November 2018, PG&E captured more than two million images of its field equipment in high fire-risk areas. Using cutting-edge software and artificial intelligence (AI) techniques, PG&E's IT team developed a technology solution that uses these images to automate some of the time-consuming steps in an inspection. This solution, known as the Sherlock tool, provided PG&E with in-depth knowledge of the state of its equipment.

The Sherlock tool allowed inspectors to mark-up potential equipment problems on high-resolution images from their desks, while training computer-vision models to classify images and automatically detect potential issues, and further adding metadata to enable searchability of these images across the enterprise. At a high level, Sherlock enabled three key business capabilities:

- Enhanced, efficient asset inspections and related workflows, with safety built-in;
- Easy search and access of asset imagery and associated data; and
- End-to-end traceability (who inspected what, when, etc.), and near real-time reporting.

As the Sherlock tool continues to be developed and deployed, AI models are being carefully integrated, requiring the inspector to confirm the correctness of the models' predictions. Inspector responses will continue to be leveraged to improve model results over time. The enablement of A/B testing, which is a simple research methodology that compares two versions of a single variable to determine user preference, and additional metrics like inspection time and number of issues identified will be used to measure the effect of each model on inspector behavior and performance.

Sherlock is an ongoing initiative with new features released to user groups on a periodic basis. The first release of the tool was put into use in March 2019. Since then, new features and enhancements have been introduced every two weeks, and the plan is to continue to provide new features into 2021 and beyond.

The key PG&E teams that executed and continue to support this work are the IT Data and Analytics team in partnership with the Aerial and Specialized Inspections team from EO.

3) Enterprise Estimating Solution Fire Functional Upgrade

The Electric Distribution EES Fire Functional Upgrades initiative was an effort designed to improve the functionality of the EES tool by incorporating specific estimating and scheduling requirements for System Hardening and WSIP restoration efforts. The expected outcome of this program was to improve the estimating and scheduling of Electric Operations System Hardening and restoration field jobs.

The program was delivered in two major workstreams. The first workstream focused on improving the functionality of the existing cost estimating tool. This upgrade entailed the following:

- Enabling Post Estimates for EES Orders;
- Improving SAP/EES system performance; and
- Fixing 40 outstanding unfulfilled requirements in EES directly related to System Hardening and restoration efforts.

The second workstream focused on improving functionality within the SAP system, specifically those components that interfaced directly with the cost estimating tool. The key objective was to streamline the performance of the cost estimating tool suite. This upgrade entailed the following:

- Enabling Associate Distribution Engineers to create mass orders and conduct order processing;
- Auto-creating the Geographical Information Systems Work-in-Progress Cloud to support mass order creation; and
- Enabling real-time scheduling and work bundling by providing selection criteria and notification to list display by group.

This project was developed and delivered at PG&E facilities in a joint effort between third party consultants and internal PG&E teams. The first workstream was executed from April 2019 to December 2019 by a third-party contractor. The second workstream was completed, in parallel, by PG&E's SAP Work Management IT Team between February 2019 and December 2019.

4) Pronto Forms

In direct response to a request from field resources for mobile tools to better outfit inspection resources, IT developed Pronto Forms for Electric Operations asset inspections. While the Pronto Forms were designed to address transmission, distribution, and substation asset inspection requirements, PG&E prioritized rollout of the product to WSIP inspectors.

This technology solution was developed by leveraging both the Pronto mobile/webpage platform and the Sherlock platform, while incorporating field inspection data from across PG&E's service territory with a particular focus on Tier 2 and Tier 3 HFTD areas. Although initial planning and design work was initiated in November 2018, the core effort to develop and deploy the product was completed between January and September of 2019, with final deployment to WSIP inspectors in November 2019.

As with many technology solutions described in this chapter, the initiative was supported by several teams in PG&E's IT and Electric Operations organizations as well as Electric Distribution third-party inspection resources. The IT core teams for product development and deployment consisted of Ground Inspections and Aerial Inspections. IT Infrastructure and Application teams completed the development and support of the tool and associated reporting process, while Electric Distribution third-party resources provided asset inspection data which helped to build core workflows and checklists. The IT and core business teams were based out of San Ramon and San Francisco PG&E headquarters, and the field team (PG&E and third-party inspectors) worked across Tier 2 and Tier 3 HFTD areas within PG&E's service territory.

5) Transmission Support Structures

The Transmission Support Structure (TSS) initiative began in early 2018 and is anticipated to deploy for use by field resources by

December 2020. This initiative was designed to address specific reporting requirements for tower structures as instructed in General Order (GO) 95 Rule 44.2, and to streamline redundant procedures related to these reports to reduce error rates and increase efficiency. Per GO 95 Rule 44.2, transmission pole/tower load calculation reports must be retained in a repository for the life of the structure, and the repository must be searchable and refreshable.

The TSS initiative is building a new Transmission Load Database (TLDB) that will contain the necessary attributes to create the required reports and search tools as stipulated in GO 95 Rule 44.2. The initiative will create a version-controlled repository for Power Line System (PLS) computer aided design and drafting (CADD) software models that will enable estimators to have a single place to check in and check out transmission asset models. Doing so will eliminate lost and/or redundant work through use of version control to keep track of the files and file types associated with transmission jobs.

The initiative team is leveraging SAP and PLS-CADD to create the models that will be fed into a new tool called Grid Search, that will then populate the TLDB and update the model versions. The solution will be integrated with PG&E's SAP and GIS systems of record to ensure information is consistent across PLS-CADD, TLDB, GIS, and SAP.

PG&E will use Grid Search to populate the TLDB and update PLS – CADD with the latest version of the transmission asset model. The TLDB will act as a record repository for the asset models and associated reports and will be updated as new models are loaded into Grid Search. Grid Search will then be able to create the necessary reports that are filed against the asset record. The Grid Search tool provides several enhanced capabilities, including:

- Storing pole structure loading documentation for transmission support structures and ensuring compliance with GO 95 Rule 44.2;

- The ability to quickly retrieve model and associated version information from a single storage location;
- Leveraging past modeling work for future projects by updating line models as more projects are designed and built;
- Identifying potential project overlaps and conflicts;
- Using the latest imagery and LiDAR information;
- Allowing users without a PLS-CADD license to view information unavailable outside of PLS-CADD; and
- Building in server-based reports that improve efficiency and reliability.

The team working on the delivery of this initiative includes both PG&E business and IT resources, IT staff augmentation and managed service contract resources, as well as the vendor that developed the Grid Search tool.

6) Miscellaneous Small Technology Solutions

Other IT investments supporting the IT WSIP included the buildout of microsites, data and image management for aerial inspections, and enhancements to PG&E's Field Automation System.

PG&E built microsites across different parts of its service territory that served as centralized hubs for the inspections being performed in the respective regions. The work to stand up the microsites involved running network connectivity, setting up computers, and installing necessary peripheral equipment. This also included the dispatch of IT resources to assist with troubleshooting and new resource onboarding as well as ongoing support to install and configure tools to allow onsite personnel to manage inspection work in the region.

The aerial inspection work included the implementation of tactical solutions to enable the collection, ingestion, storage and analysis of drone and helicopter images in support of asset inspections. This also included the development of data and imagery quality assurance processes prior to image review.

In support of the IT WSIP, PG&E implemented two key enhancements to its Field Automation System. The first of these enhancements enabled troublemen to more easily report information related to ignitions, outages, and asset failure events. This change provided the user with comment fields as well as the ability to attach pictures or other relevant documents. The second enhancement enabled troublemen to use their mobile devices to capture GPS coordinates of the fault location for outage field orders so the engineering team could more readily identify the equipment that failed.

c. IT Asset Risk Program

This program category includes two types of major initiatives, as reflected in the table below.

TABLE 6-5
2019 IT ASSET RISK PROGRAM
(THOUSANDS OF DOLLARS)

Line No.	Major Initiatives	Capital	Expense
1	VM Next Priority Insights	$1,900	$245
2	System Tool for Asset Risk (STAR) – ED Conductor Cap and Hardening	840	91
3	Total	$2,739	$336

These initiatives are discussed in turn in the subsections that follow.

1) Vegetation Management Next Priority Insights

The VM Next Priority Insights initiative was an effort to: (1) deepen PG&E's knowledge and understanding of remote sensing data collected by external vendors; (2) develop methodologies and automated tools to ensure that the quality of data produced by those vendors meets pre-determined thresholds; and (3) create data libraries in support of various related downstream PG&E efforts. As a result of this effort, PG&E's Electric Distribution vegetation management teams had access to trusted information about trees posing a risk to the distribution network in HFTD areas, and Map Correction teams had access to reliable

LiDAR data sets that informed efforts to improve the quality of asset location data. Other teams, including the Electric Distribution Hardening Risk Assessment and Distribution Risk Modeling teams, have also used the data or are evaluating how to use it to better inform their analysis and model outputs.

The VM Next Priority Insights initiative was coordinated, facilitated, and implemented by PG&E's IT organization in collaboration with Electric Distribution's Vegetation Management department and external remote sensing third-party vendors. This initiative was started in the latter part of 2018 and was completed with the delivery of the last of the data collected in late 2019. In 2019, data was collected for 25,000 miles of Electric Distribution assets in Tier 2 and Tier 3 HFTD areas.

2) System Tool for Asset Risk Initiatives – Electric Distribution Conductor Cap and Hardening

The STAR Electric Distribution Hardening and Conductor Cap solutions supported asset health and risk scoring as well as prioritization and planning for conductor spans. The Conductor Cap solution was largely completed in 2018 and provided a key input into the Electric Distribution Hardening solution in 2019. Both efforts will provide additional value in the larger asset strategy that is being developed across the Company.

The STAR Conductor initiative acquired and integrated data on qualities of conductor spans from five different databases and provided the Conductor Replacement team with a curated data set that informed prioritization of conductor spans for replacement as part of the 2020-22 plan. The initial data set in this product enabled various asset insights on conductor spans in an abbreviated timeframe to better inform decision-making. This resulting plan was then input into the Electric Distribution Hardening solution, which further integrated it with other asset hardening plans. The combined results assisted the Conductor Replacement team in scheduling asset replacements.

The STAR Conductor initiative was coordinated, facilitated, and implemented by PG&E's IT organization and staff augmentation resources in collaboration with PG&E's Electric Distribution asset management department.

d. IT Vegetation Management Program

This program category includes one major initiative, known as Vegetation Accelerated Work, which is reflected in the table below.

TABLE 6-6
2019 IT VEGETATION MANAGEMENT PROGRAM
(THOUSANDS OF DOLLARS)

Line No.	Major Initiatives	Capital	Expense
1	Vegetation Accelerated Work	$269	$44
2	Total	$269	$44

Early in 2019, IT reviewed the 2019 WMP to ensure that all accelerated work for the year would consider these requirements as a priority. Among the priorities identified was the need to procure specific devices for tree listing activities during VM inspections. The ideal unit for this job is the GeTAC, a ruggedized mobile tablet. These devices are preferred for this type of inspection work because they have been field tested and determined to hold up to the work needing to be completed in terms of durability (reliability of the equipment while operating under adverse field and weather conditions), as well as having the needed memory capacity to support work in areas that do not have WiFi or cell phone service. At the time, however, there were insufficient GeTAC devices in PG&E's inventory to satisfy 2019 WMP inspection requirements, compounded by a long materials lead time. In addition to long lead times, the GeTAC units are typically purchased as a part of a larger lifecycle program and prioritized across a much larger portfolio of technology spend. However, because of the urgency of completing this inspection work, the purchase of GeTAC devices was approved as an accelerated investment to satisfy the safety requirement to conduct patrols of trees encroaching on and threatening our overhead electric facilities.

As a part of this investment, IT procured and provisioned 100 GeTACS with associated rugged protective cases to contracted tree inspectors to assist them in completing required vegetation inspections and patrols. The GeTAC units were procured, provisioned, and deployed by the IT team in May 2019.

D. Relationship Between IT Costs and Electric Distribution Costs

Although technology is referenced in previous chapters in this filing, primarily in chapter 2, the specific IT work shown and discussed in this chapter is markedly different from any technology costs discussed in chapter 2. The specific IT programs described in this chapter focus on the design, development, and deployment of specific technology solutions in support of the Electric Distribution programs. As discussed in the program descriptions above, many of these solutions are built in collaboration with Electric Distribution teams, and the technology products and services that comprise these solutions are not deployed to those teams until the users have provided feedback and IT has addressed any immediate operational concerns. This collaborative approach does not mean that the costs related to the programs discussed in this chapter are managed or recorded outside of the IT organization. IT is the only organization within PG&E that has the resources and capabilities to build the technology solutions required for Electric Distribution to execute wildfire mitigations that rely on advanced technology. In addition, all the planning orders that represent the unique financial records for the costs discussed in this chapter are built, tracked, and owned by the IT organization and managed in a separate operational budget. While IT, as a support organization, does provide services that are embedded within the Electric Distribution organization, none of those services are included in the costs or testimony for Chapter 6.

E. Conclusion

All of IT's technology solutions in support of wildfire mitigations are prioritized and reviewed by IT leadership prior to approval and execution. In addition, IT shares their work plans with Electric Distribution to ensure alignment of proposed technology solutions to the intended resource group benefitting from the solution and the associated wildfire mitigation effort. This chapter describes the reasonable incremental costs incurred by PG&E in 2019 for those specific, approved IT programs necessary to support the wildfire mitigation efforts outlined in the 2019 WMP. PG&E's 2019 WMP entailed an unprecedented and aggressive set of programs, requiring a new set of products and services to promote efficiency. The technology solutions discussed in this chapter are adaptable and iterative by design and will continue to provide value over time.

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS
CHAPTER 7
2017-2019 RESIDENTIAL RATE REFORM
MEMORANDUM ACCOUNT COSTS

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2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS
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2017-2019 RESIDENTIAL RATE REFORM MEMORANDUM ACCOUNT COSTS

A. Introduction

This chapter proposes a refund of $3,738,246 of the $57,900,000 recovered in Pacific Gas and Electric Company's (PG&E) Annual Electric True-up (AET) for costs related to the Residential Rate Reform Order Instituting Rulemaking (RROIR)[1] during the 2017-2019 General Rate Case (GRC) cycle. In the 2017 GRC Phase 1 Decision (D.) 17-05-013, the California Public Utilities Commission (CPUC or Commission) authorized PG&E to collect $19.3 million annually, subject to refund, through the AET for costs recorded to the Residential Rate Reform Memorandum Account (RRRMA).[2]

As provided for in the 2017 decision:

> PG&E shall be authorized to collect in rates, subject to refund … $19.3 million annually through PG&E's AET advice letter filing up to a cumulative total of $57.9 million for the 2017–2019 period…. All of the 2017 and beyond costs booked to the RRRMA shall be no longer subject to refund to the extent that PG&E demonstrates in the separate application or testimony that its expenditures were incremental, verifiable, and reasonable, consistent with the requirements of D.15-07-001, and consistent with any relevant Commission rulings and approvals of implementation plans in Rulemaking (R.) 12-06-013, including, without limitation, plans submitted by PG&E and approved through advice filings for time-of-use (TOU) Default Pilots; Default TOU Rates; Residential Rate Reform Marketing, Education and Outreach (ME&O); and implementation of other requirements required by D.15-07-001 and in R.12-06-013 and related proceedings.

During 2017-2019, PG&E recorded $54,161,754 in the RRRMA, which is $3,738,246 less than the $57,900,000 recovered in the AET.

B. Regulatory Background

In D.15-07-001, the Commission set a course for Residential Rate Reform, including the transition of most residential customers from a tiered, non-time

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1 R.12-06-013.

2 D.17-05-013 Settlement Agreement (SA), Subsection 3.1.5.2. as reflected in the Settling Parties' April 24, 2017 proposed alternative provisions.

varying electricity rate to a default TOU electricity rate. D.15-07-001 directed the Investor-Owned Utilities[3] (IOU) to file a Tier 1 advice letter establishing new memorandum accounts to track verifiable incremental costs associated with: (a) TOU pilots, (b) TOU rates, including hiring of a consultant or consultants to assist in developing study parameters, (c) marketing education and outreach costs associated with the rate changes approved in the decision, and (d) other reasonable expenditures as required to implement the decision.[4] The Commission approved PG&E's advice letter establishing the RRRMA on August 19, 2015.[5]

The purpose of this testimony is to document the costs PG&E recorded in its RRRMA for the 2017-2019 GRC cycle to implement the requirements of D.15-07-001, and related Commission rulings, advice filings, and resolutions.[6] These Commission rulings, advice filings, and resolutions are referenced in the workpapers supporting this chapter which include detailed annual reports on Commission-mandated rate reform activities and costs.

C. 2017-2019 RRRMA Cost Recovery Proposal

During 2017-2019, PG&E recorded incremental costs related to Residential Rate Reform totaling $54,161,754 in the RRRMA. Per the 2017 GRC Phase 1 SA to recover these costs, PG&E collected $19.3 million annually, subject to refund, through PG&E's AET, as summarized in Table 7-1 below. PG&E proposes to refund $3,738,246 in costs collected through the AET in excess of the $54,161,754 recorded to the RRRMA. Comprehensive year-by-year reports detailing the rate reform activities are provided in the workpapers supporting this chapter.

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3 PG&E, San Diego Gas & Electric Company (SDG&E) and Southern California Edison Company (SCE).

4 Ordering Paragraph (OP) 12.

5 Advice Letter 4672-E, filed July 22, 2015.

6 In 2015 and 2016, PG&E recorded costs of $20.5 million and applicable interest in the RRRMA to implement D.15-07-001. As directed in D.17-05-013, PG&E submitted testimony on July 11, 2018, in R.12-06-013 proposing recovery of the 2015-2016 RRRMA costs. D.19-09-004 OP 1, authorized PG&E to recover $16.2 million in costs recorded in the RRRMA in 2015 and 2016 as stipulated with the Public Advocates Office.

TABLE 7-1
2017-2019 RRRMA COST RECOVERY PROPOSAL

Line No.	Year	Recovered in AET[(a)]	Recorded	Bill Protection[(b)]	Total RRRMA Costs	Proposed Refundable[(c)]
1	2017[(d)]	$19,300,000	$17,493,790	$299,134	$17,792,924	$1,507,076
2	2018	19,300,000	16,339,578	0	16,339,578	2,960,422
3	2019	19,300,000	20,029,252	0	20,029,252	(729,252)
4	Total	$57,900,000	$53,862,620	$299,134	$54,161,754	$3,738,246

(a) Not including Revenue Fees and Uncollectibles.
(b) Bill Protection for the Opt-in TOU Pilot (see Section D1).
(c) Recovered – (Recorded + Bill Protection).
(d) 2017 authorized Revenue Requirement was collected in 2018 AET due to a delay in the 2017 GRC Phase I Decision.

D. Summary of 2017-2019 RRRMA Costs by Initiative and Cost Category

The 2017-2019 costs recorded to the RRRMA supported the implementation of the following CPUC-mandated Residential Rate Reform initiatives:

1) Opt-in TOU Pilot;
2) Activities Supporting Residential Rate Changes;
3) Program Management Office (PMO);
4) High Usage Surcharge (HUS);
5) Rate Comparison Mailers;
6) Rate Elimination and Transition;
7) Default TOU Pilot;
8) Full Default TOU Transition;
9) TOU Billing Operations; and
10) Statewide ME&O.

Table 7-2 summarizes the costs for each of these initiatives broken down by cost category:

TABLE 7-2
SUMMARY OF 2017-2019 RRRMA COSTS BY INITIATIVE

Initiative	Subcategory	2017	2018	2019	2017-2019 Total
Opt-in TOU Pilot	Contract	$1,177,101	($9,407)	$0	$1,167,694
	Incentives	$1,106,400	$0	$0	$1,106,400
	Labor	$700,250	$40,211	$0	$740,461
	Materials	$77,569	($3,926)	$0	$73,643
	Bill Protection	$299,134	$0	$0	$299,134
	Bill Protection Adjustment	$0	$1,504	$0	$1,504
Opt-in TOU Pilot Total		**$3,360,454**	**$28,382**	**$0**	**$3,388,836**
Activities Supporting Residential Rate Changes	Contract	$481,455	$705,543	$641,499	$1,828,497
	Labor	$22,287	$65,303	$21,247	$108,838
	Materials	$4,995	$0	$0	$4,995
Activities Supporting Residential Rate Changes Total		**$508,738**	**$770,845**	**$662,746**	**$1,942,330**
Program Management Office	Contract	$2,744	$0	$0	$2,744
	Labor	$413,674	$0	$0	$413,674
Program Management Office Total		**$416,418**	**$0**	**$0**	**$416,418**
High Usage Surcharge and Tier Consolidation	Contract	$1,480,718	$263,841	$8,579	$1,753,138
	Labor	$1,379,973	$288,735	$167,769	$1,836,477
	Materials	$237,987	$200,038	$147,275	$585,299
High Usage Surcharge and Tier Consolidation Total		**$3,098,678**	**$752,614**	**$323,622**	**$4,174,914**
Rate Comparison Mailers	Contract	$1,001,566	($5,668)	($3,718)	$992,179
	Labor	$820,025	$0	$0	$820,025
Rate Comparison Mailers Total		**$1,821,591**	**($5,668)**	**($3,718)**	**$1,812,204**
Rate Elimination and Transition	Contract	$309,189	$58,294	$85,207	$452,689
	Labor	$67,624	$20,525	$223,660	$311,809
Rate Elimination and Transition Total		**$376,813**	**$78,819**	**$308,867**	**$764,499**
Default TOU Pilot	Contract	$3,296,872	$2,896,938	$223,049	$6,416,860
	Labor	$3,795,837	$4,110,352	$477,939	$8,384,127
	Materials	$0	$201,497	$28,720	$230,217
Default TOU Pilot Total		**$7,092,709**	**$7,208,787**	**$729,708**	**$15,031,204**
Full Default TOU Transition	Contract	$47,595	$169,123	$1,436,163	$1,652,881
	Labor	$135,040	$690,708	$2,079,939	$2,905,686
Full Default TOU Transition Total		**$182,635**	**$859,831**	**$3,516,102**	**$4,558,568**
TOU Billing Operations	Labor	$934,889	$193,749	$237,089	$1,365,727
TOU Billing Operations Total		**$934,889**	**$193,749**	**$237,089**	**$1,365,727**
Statewide ME&O	Contract	$0	$6,425,293	$14,226,193	$20,651,486
	Labor	$0	$26,926	$28,643	$55,568
Statewide ME&O Total		**$0**	**$6,452,219**	**$14,254,836**	**$20,707,054**
Grand Total		**$17,792,924**	**$16,339,578**	**$20,029,252**	**$54,161,754**

1. Opt-In TOU Pilot

D.15-07-001 required the IOUs to design an opt-in residential TOU pilot for immediate implementation.[7] PG&E's Opt-In TOU Pilot team focused on the following activities in 2017 and 2018:

a. Ongoing Pilot Implementation

Ongoing Pilot Implementation activities included participant tracking, implementation of the Bidgely HomeBeat Smartphone App, administering a $200 per participant incentive, and conducting end of pilot operations. Other key costs included administering bill protection credits in 2017 totaling $299,134.[8]

b. Measurement and Evaluation

Opt-In TOU Pilot Measurement and Evaluation in 2017 and 2018 consisted of three phases of studies by vendors Nexant and Research into Action (RIA). Nexant analyzed bill and load impacts by various customer segments. RIA conducted surveys investigating economic and health hardship as well as rate understanding, engagement, and satisfaction and analyzed the survey results among various customer segments.

c. Customer Research

In 2017, PG&E engaged Travis Research to conduct qualitative research on customers' experience on the Opt-in TOU Pilot rates during the winter season.

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[7] D.15-07-001, p. 166.

[8] Resolution (Res.) E-4762 p. 27, dated February 25, 2016 directed PG&E to record the Opt-in TOU Pilot Bill Protection payments to the RRRMA. In Advice Letter 4979-E p. 75, filed December 16, 2016, PG&E proposed that Bill Protection payments should be considered a revenue under-collection and not recorded to the RRRMA. Res.E-4846 page 21, dated August 10, 2017, authorized PG&E to treat Bill Protection payments for the Default TOU Pilot as a revenue under-collection rather than recording them to the RRRMA. PG&E was directed to record any generation revenue shortfall in PG&E's Utility Generation Balancing Account, and any distribution revenue shortfalls PG&E's Distribution Revenue Adjustment Mechanism; Most Opt-in TOU Pilot Bill Protection payments were made in the fall 2017 shortly after the participants concluded their first 12 months enrolled in the pilot rate plans. Participants remained enrolled in the pilot rate plans until the end of the year, when they were given the option to select another TOU rate plan or, if they made no selection, return to the tiered rate plan.

d. Customer Communications

In 2017-2019, PG&E engaged Brand Cool Marketing, Slalom, Pitney Bowes Bank and The Act 1 Group to support Opt-in TOU Pilot customer communications. PG&E also engaged with Studio19 to provide language translation services in the creation of Spanish versions of customer communications. Opt-in TOU Pilot customer communication campaigns focused on the spring mid-day super off-peak and off-peak periods, end of bill protection, tools to help manage energy use, summer seasonal education, end of pilot notifications, Bidgely HomeBeat Smartphone App communications, and unenrollment letters.

2. Activities Supporting Residential Rate Changes

This category includes supporting activities to implement the residential rate reform ME&O plan including:

a. Diverse Communities Targeted Outreach

The 2017 GRC SA (Application (A.) 15-09-001) Subsection 3.1.5.5.1 required PG&E to spend 33 percent of costs recorded in the RRRMA up to a maximum of $1.7 million over the 2017-2019 period for activities related to education and outreach to communities of color and underserved communities on ways to mitigate bill impacts from rate reform changes.[9] In 2017, a variety of activities were conducted including: a Community Based Organization (CBO) Training Study, Community Events, an e-newsletter, and quarterly meetings of the Community of Color Advisory Board as specified in the SA.

b. ME&O Tracking Study

In D.15-07-001, the Commission discussed the importance of providing adequate ME&O to customers and directed the IOUs to work with other parties to create a working group to examine ME&O for the transition to default TOU rates, including a longitudinal customer study.

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9 D.17-05-013, May 11, 2017: *Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement for 2017-2019.* A.15-09-001, Exhibit (PG&E-6), WP 3-16, Line 3: Settlement Subsection 3.1.5.5.1 required 33 percent of $1,679,000 per year be spent on communities of color and underserved communities.

The working group also examined the changes to the tiered rate structure, revisions to the minimum bill and bill comparison tools.

Hiner and Partners continued the ME&O Metrics Tracking Study, launched in March 2016, measuring awareness, understanding, and engagement with rate reform and the transition to TOU.

3. Program Management Office

PG&E established a PMO in 2016 to develop the organizational structure and various project governance processes for the initial planning and implementation of residential rate reform initiatives and pilots. PG&E dissolved the PMO at the end of 2017, once the PMO completed its work, which included: establishing quality assurance and quality control processes for customer communications; ensuring alignment among a broad group of cross-functional internal stakeholders; internal and external reporting; coordination for working group meetings and presentations; regulatory compliance tracking; integrated project plans; communications plans; regulatory support; financial and budgeting support; document retention; and steering committee coordination.

4. High Usage Surcharge

Effective March 1, 2017, PG&E reduced the number of tiers in the E-1-Tiered Rate Plan from four to two and implemented the HUS. The HUS is applied to electricity usage exceeding 400 percent of the baseline allowance during the monthly billing cycle. There were two groups of customers considered "at risk" of incurring the HUS:

1) Customers whose usage reached 400 percent of baseline, at least once in a 12-month period, defined as June 1, 2015 through May 31, 2016; and
2) Customers whose usage reached between 350 and 399 percent of baseline, at least three times during the 12-month period, defined as June 1, 2015 through May 31, 2016.

In 2017-2019, PG&E provided or prepared for a variety of communications, tools and support to customers meeting the above defined customer groups. These HUS-related communications included notifications to customers at risk of incurring the HUS, Contact Center

Representative training to communicate effectively with customers who would call with questions or concerns about the HUS (this training included information on tier collapse and structural rate change initiatives), and a "High Usage Alerts" (HUA) tool designed to help customers by providing a warning in advance of incurring the HUS, which gave customers an opportunity to take action during the remainder of their billing cycle to reduce usage and potentially avoid the HUS.

Communication materials included relevant combinations of the following information:

- Explanation of the HUS and where to find more information, such as the PG&E website and Contact Center;
- Reference to tips, tools and programs for reducing usage and bills;
- Medical Baseline Allowance eligibility information;
- Rebates for energy-efficient products;
- Tools available, such as HUA and using the Rate Comparison Tool;
- Net Energy Metering (NEM) 1.0 customers received NEM specific tips, tools, and instructions to conserve; and
- California Alternate Rates for Energy (CARE) customers were provided with information on the Energy Savings Assistance program and non-CARE customers were provided with information on The Energy Upgrade California® (EUC) Home Upgrade.

5. Rate Comparison Mailers

In D.15-07-001,[10] the Commission ordered the IOUs to provide customers with a paper bill comparison (also referred to as Rate Comparison Mailers) twice per year beginning in 2016.[11] PG&E sent more than 150,000 rate mailers in 2016 as part of a test-and-learn effort. Per the Prehearing Conference (PHC) Statement filed by PG&E on February 3,

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[10] D.15-07-001, p. 142.

[11] Subsequent assigned Administrative Law Judge (ALJ) rulings, issued on March 14, 2016, and July 22, 2016, provided additional details and clarity on the bill comparisons that were sent to customers in 2016, reducing PG&E's requirement to one bill comparison delivered in the fall of 2016 to a group of at least 100,000 customers for a test-and-learn campaign.

2017,[12] PG&E proposed replacing the 2017 Spring rate mailer with a second "test-and-learn" effort launching only one time in the fall 2017. The CPUC subsequently approved this proposal on February 6, 2017.[13]

In June 2017, PG&E sent approximately 200,000 "test-and-learn" rate mailers to customers in the form of direct mail and e-mails. The overall objective was to encourage the customer group to voluntarily switch to a TOU rate plan (such as E-TOU-A or E-TOU-B) and test the effectiveness of the bill comparisons to increase customer understanding of rate options.

On September 5, 2017, PG&E received a ruling from the ALJ in R.12-06-013 ordering the suspension of any semi-annual bill comparison mailers pending further Commission instruction after consideration of an overall ME&O strategy to promote the objectives in D.15-07-001.

6. Rate Elimination and Transition

In 2017-2019, Rate Elimination and Transition activities included Opt-In TOU Rate Support[14] and the E-7 Rate Transition. PG&E provided support to customers who had opted in to either the E-TOU-A or E-TOU-B rate with TOU Welcome Kits, and a summer rate support campaign. PG&E also completed the transition of E-7 customers to E-TOU-A, and the subsequent elimination of the E-7 Rate, as authorized by D.15-07-001.[15]

7. Default TOU Pilot

D.15-07-001 required the IOUs to conduct residential default TOU pilots in 2018.[16] PG&E submitted Advice Letter 4979-E on December 16, 2016 to propose launching its residential Default TOU Pilot design in March 2018 and continuing the pilot for one year. PG&E's Default TOU Pilot team focused on the following activities in 2017 to prepare for the pilot launch in 2018:

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12 R.12-06-013, February 3, 2017 PHC, Statement of PG&E (U 39 E).

13 R.12-06-013, February 6, 2017 PHC, Transcript pp. 423-427.

14 Opt-in TOU Rate Support refers to programs to help customers who voluntarily enrolled in a TOU rate and should not be confused with the Opt-in TOU Pilot, which recruited volunteers to participate in an 18-month study where the volunteers were assigned to one of four different rate plans.

15 pp. 155-157.

16 p. 166.

a. Customer Outreach

Default TOU Pilot customer outreach included the development, testing, refining and finalization of notification materials in preparation for the launch of the Default TOU Pilot in 2018. These notifications included 90-, 60-, and 30-day direct mail and e-mail notifications. In addition, PG&E produced welcome, newly ineligible, opt-out, seasonal, and end of bill protection communications. In 2018, customers received multiple notifications to inform them about their upcoming rate plan change, choices, and how to take action. PG&E analyzed customer responses to different combinations of notification cadences and channels as a test to inform the communication plan for full TOU Transition.

PG&E worked with Gridium Inc. and Gridx to set up a website that featured a specific login page for customers identified for the rate plan transition to review their personalized rate comparison online and make a rate choice. PG&E also coordinated with Genesys Telecommunications Labs to conduct outbound calls to approximately 7,000 customers with the highest annual bill impacts who had not yet acted after the final 30-day notification.

b. Pilot Participant Monitoring

In 2017, PG&E developed the process for identifying customers eligible for TOU Transition, and the transition to interval billing, which allows customers with a SmartMeter™ to be billed on a TOU rate. Customers were also assigned to a research group (or track) for ME&O testing. PG&E also created a dashboard to monitor customer participation in the Default TOU Pilot in 2018 in response to Commission Res.E-4882.[17]

c. Customer Service Representative Training

In 2017, PG&E trained approximately 1,200 Customer Service Representatives (CSR) to assist customers throughout the Default TOU Pilot. PG&E also created guides to assist representatives with facts and information while having conversations with customers. In 2018, PG&E

[17] OP 5.

continued to educate CSRs on the TOU transition with refresher trainings and to monitor calls for quality.

d. Customer Insights

In 2017-2019, PG&E conducted customer research regarding:

- Default TOU Pilot notifications – this includes transition notifications, 60-day rate comparisons, and welcome letters;
- Design Thinking Research – the three IOUs worked with the research firm EngagedIN in 2017 at the direction of the CPUC to conduct research with customers to better understand their general concerns about rates as well as how they would design rates and adapt to TOU rates;
- ME&O and Experience Survey Tracking – The Quantitative ME&O and Experience Survey, conducted with Hiner and Partners, was designed to provide an ongoing evaluation of customer awareness, understanding and experience of TOU and performance on distinct goal metrics.[18] The baseline survey was completed in 2018. In 2019, analysis of Waves 2 and 3 of the survey were completed among PG&E's Default TOU Pilot customers; and
- The Qualitative ME&O and Experience Evaluation was designed to add depth and context to the ME&O and Experience Survey Tracking.

e. Community Choice Aggregation (CCA) Coordination

In 2017-2019, PG&E coordinated with the three CCAs that participated in the Default TOU Pilot: Marin Clean Energy, Sonoma Clean Power, and Silicon Valley Clean Energy, and the non-participating CCAs. Topics included customer notifications, customer experience, customer tools, and TOU Briefings. PG&E also began coordinating with all CCAs in its territory to educate them about the Full TOU Transition in 2020 and lay the groundwork for their participation in the transition.

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[18] Res.E-4882, p. 46, #4 requires PG&E to provide documentation of performance on the TOU Full Transition ME&O goal metric targets in any application or proposal for recovery of costs related to the plan recorded in the RRRMA. Workpapers supporting this chapter detail the performance of Default TOU Pilot customers on the goal metric targets and shows 7 of 8 final approved goal metric targets were met by May 2019.

f. Media, Elected Officials, Employees and CBO Education

In 2017-2019, PG&E developed and conducted training to more than 300 customer facing employees such as account representatives, gas service representatives, field metering representatives, public affairs, and government relations. PG&E also prepared communications, talking points, and frequently asked questions for these teams and several general employee communications.

g. Measurement & Evaluation

In 2018, PG&E's Measurement, Data, and Analytics team gathered data on the 13 test notification tracks for the four stages of Default TOU transition: (1) customer default notifications, which were delivered between January 2018 and March 2018; (2) the welcome communication; (3) summer and winter seasonal support; and (4) the end of bill protection period notification.

In 2019, PG&E conducted two separate load and bill impact studies. PG&E submitted these studies to the Energy Division and also presented them to the TOU Working Group.[19]

h. Information Technology (IT)

PG&E performed the bulk of the IT work for the Default TOU Pilot in 2017 and 2018. Throughout 2017, members of the TOU Transition team, including the Billing Operations, IT, and Pricing Products departments, developed the business and functional requirements for the billing system and on-line tools to support the TOU Transition. In 2018, PG&E generated automated notifications for customers transitioning to TOU and monitored and facilitated customer choices and activities as the Default TOU Pilot customers interacted with CSRs and through the self-service channels.

i. Transitions to Interval Billing for Default TOU Customers

In preparation for the Default TOU Pilot, in 2017, PG&E transitioned E-1 customers with a SmartMeter who were also otherwise eligible for

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[19] D.15-07-001, OP 13 and OP 14, required the IOUs to form working groups to address the issues regarding TOU rate design and study and marketing education and outreach as detailed in the decision and as modified or revised during Phase 3 of the proceeding.

Default TOU Transition to interval billing. Costs for these transitions also included processing billing exceptions that arose when a customer was newly transitioned to interval billing and the meter was not yet accurately transmitting data. In addition, during 2018 and 2019, there was extensive preparation and planning for the transition of about 2.5 million customers to interval billing for the Full Transition in 2020.

8. Full Default TOU Transition

In December 2017, PG&E filed A.17-12-011 which included PG&E's proposal for full implementation of default TOU rates for residential customers ("Full Default Time of use Transition"),[20] including a menu of optional rate plans to be offered to all customers at the same time as Full Default TOU Transition. PG&E filed Supplemental Testimony on August 17, 2018, addressing numerous operational topics and proposed Guiding Principles for the Full Default TOU Transition as well as a refined geographic implementation plan that incorporated input from CCAs.

In 2018 and 2019, PG&E continued detailed planning for implementation of the full transition, started automating processes for the full transition, and developed the infrastructure to provide customer support for the transition. PG&E also conducted bi-weekly calls with all 12 CCAs that were expected to participate in the Full Default TOU Transition that was planned to begin in October 2020.

In 2019, PG&E finalized six pieces of TOU communications for the Full Default TOU transition:

1) 90 Day Notification – Direct mail, to be sent to customers approximately 90 days in advance of their scheduled transition date;
2) 30 Day Notification – Direct Mail, to be sent to customers approximately 30 days in advance of their scheduled transition date;
3) 30 Day Notification – E-mail, with the same content as the Direct Mail piece above and to be e-mailed to all customers for whom PG&E has an e-mail address approximately 30 days in advanced of their scheduled transition date;

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[20] D.15-07-001, OP 9, required PG&E to file a residential rate design window application no later than January 1, 2018, proposing default TOU rates for residential customers.

4) Ineligible Letter – Direct mail, to be sent to customers that are ineligible to transition because of disqualifying criteria such as enrolling in a financial assistance program or the medical baseline program;

5) Opt-Out Letter – Direct mail, to be sent to customers who have chosen an alternate rate plan to the TOU (Peak Pricing 4-9 p.m. Every Day) rate plan; and

6) Business Reply Card Exception Letter – Direct mail, to be sent to customers when PG&E cannot process the business reply card, which will be attached to the 90 Day Notification (for example, because the card was not signed).

In 2019, PG&E also decided to include a Business Reply Card (BRC) in its 90-day notifications. In addition to reviewing the data and survey results regarding the BRCs tested in SCE's and SDG&E pilots, PG&E conducted customer research to finalize the design of its BRC.

PG&E also launched a territory-wide Rate Options digital campaign in March 2019 featuring an approximately 45-second pre-roll video in English or Spanish with information about rate plan options encouraging customers to visit their online account to view a rate comparison.

In addition, a July 22, 2016, ALJ Ruling directed the IOUs to include in their ME&O plans a detailed plan for integrating rate discussions into the start and transfer service process. During 2017-2019, as part of the Start/Transfer Pilot, PG&E developed and tested a decision tree tool and a script for CSRs to use to help customers select a rate plan when starting or transferring service. PG&E used the results of the pilot to develop a detailed guide and implemented the guide with all CSRs. PG&E conducted call monitoring of CSRs engaging in rate conversations when customers establish or transferred service.

9. TOU Billing Operations

In the 2017 GRC, PG&E forecasted Billing Operations costs related to the transition to interval billing of NEM 1.0 and Opt-in customers not included in the Opt-in or Default TOU Pilots. The D.17-05-013 Joint Party

SA authorized PG&E to remove these costs from the GRC forecast and recover them in the RRRMA.[21]

10. Statewide ME&O

The bulk of ME&O spending outside of direct-to-customer notifications was allocated to Statewide ME&O for mass media efforts, public relations and CBO outreach. Although these Statewide ME&O efforts were funded by the IOUs, the Commission clearly stated in D.17-12-023 that PG&E has no discretion to exercise control over the design, scope, or budget of the Statewide ME&O program and that its role is limited to fiscal management.[22] A series of Commission decisions and advice letter approvals, summarized in the workpapers supporting this chapter, delineated scope, schedule and budgets for the following vendors, for work starting in 2018, subject to CPUC oversight:

- DDB – Creative Consultant;
- OMD – Media Implementer;
- IPSOS – Statewide Evaluator; and
- Coleman, Inc. – Statewide ME&O Coordinating Consultant.

E. Conclusion

As discussed above, PG&E's proposal for recovery of its 2017-2019 costs recorded to the RRRMA are reasonable and consistent with the requirements of relevant Commission rulings and approvals of implementation plans in the

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21 D.17-05-013, Subsection 3.1.5.2 of the SA, as reflected in the Settling Parties' April 24, 2017 proposed alternative provisions: "In conjunction with the removal from this GRC of PG&E's forecasted activities for pricing products (Major Work Category (MWC) EZ*), billing, revenue, and credit (MWC IS)*, and IT (MWC 2F), PG&E shall be authorized to track and record costs incurred in 2017 and beyond for residential rate reform implementation including default TOU through its RRRMA."

22 In D.17-12-023, the CPUC held that: "[t]he governance structure for EUC should apply to the statewide residential rate reform ME&O work." (p. 60, Conclusion of Law (COL) 7.) D.13-12-038, established the governance structure for EUC statewide ME&O with the Commission retaining "oversight control" (p. 90, COL 26), "overriding authority on all decisions" (p. 90, COL 27i), "control over design of or modifications to the statewide [ME&O] program" and assigned PG&E the role of the "fiscal manager for the contract" (p. 98, OP 18). The Commission later confirmed the governance structure established in D.13-12-038 by establishing the RASCI governance model for the EUC contract which assigned the role of "Accountable," and authority as approver, to the Commission, and the roles of "Supportive" and "Consulted" to the IOUs. (D.16-03-029, p. 46-50, see esp. p. 50, Table.)

RROIR. PG&E used these funds to conduct activities in support of Residential Rate Reform. These activities include conducting an Opt-in TOU Pilot and Default TOU Pilot and preparing for the Full TOU Transition. In addition, PG&E implemented the HUS, performed other rate elimination and transition activities, and tested rate mailers. PG&E also conducted ME&O activities to support customers through these rate actions and to inform outreach for the upcoming Full TOU Transition. For these reasons, PG&E requests that the Commission approve its proposed refund of $3,738,246.

PACIFIC GAS AND ELECTRIC COMPANY

2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS

CHAPTER 8

DEMONSTRATION OF INCREMENTALITY

PACIFIC GAS AND ELECTRIC COMPANY
2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS
CHAPTER 8
DEMONSTRATION OF INCREMENTALITY

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DEMONSTRATION OF INCREMENTALITY

A. Introduction

This chapter demonstrates the incrementality of the costs requested in this application. "Incremental" costs are those labor, equipment, material, contract, and other support costs associated with work that is not included in Pacific Gas and Electric Company's (PG&E or the Company) General Rate Case (GRC) authorized revenue requirements or other recovery mechanisms.

Historically, PG&E's GRC revenue requirements contemplated routine or baseline levels of emergency response activity, vegetation management, electric asset inspection work, and electric asset maintenance and replacements. In recent years, however, we have incurred costs in these work areas and through new initiatives that are incremental to the work contemplated in rates. These incremental costs include our catastrophic event response and the significant wildfire mitigation work the Company has undertaken to address heightened wildfire risks and comply with rule and policy changes in furtherance of this goal.

This chapter focuses upon two broad categories of incremental costs, the incrementality of which are discussed in section B.[1] The first category is comprised of Catastrophic Event costs, which PG&E has incurred in connection with declared emergencies. These costs are booked in the Catastrophic Event Memorandum Account (CEMA). The second category is comprised of wildfire mitigation costs (referred to as "Wildfire" costs in this chapter), which PG&E has incurred to address recent rule changes and to reduce the risk of catastrophic wildfires in our service territory. These costs are booked in the Fire Hazard Prevention Memorandum Account (FHPMA) and the Fire Risk Mitigation Memorandum Account/Wildfire Mitigation Plan Memorandum Account (FRMMA/WMPMA).

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[1] In addition to these two categories of costs (i.e., CEMA and Wildfire), this chapter also briefly explains the basis for incrementality of the other two types of costs sought in this application. These other two types—the costs recorded to the Land Conservation Plan Implementation Account (LCPIA) and the Residential Rate Reform Memorandum Account (RRRMA) —are addressed in Section B.4.

Each of the costs included in this application relates to work that is new, or in addition to, what was contemplated by PG&E's existing rates. PG&E does not forecast CEMA costs in our GRCs, and the wildfire mitigation work we performed was in response to legislation, rule, and policy changes, and environmental and risk factors, that post-date our application in our most recent approved GRC. For example, we did much of the wildfire mitigation work described in this application pursuant to our Wildfire Mitigation Plan (2019 WMP), which stems from the 2018 enactment of SB 901. Costs incurred for the work outlined in the 2019 WMP are typically booked to two memorandum accounts, the FRMMA and WMPMA.

PG&E has several mechanisms in place to ensure the incrementality of the costs requested in this application. First, as described in section C, we tracked costs associated with this incremental work in the memorandum accounts described above, which are separate from those we use to track costs comprising PG&E's base rates. The costs were also tied to specific work orders to ensure that they had not already been recovered through existing rates, other proceedings, or any other recovery mechanism.

Second, to further support this application, we engaged an independent auditor, Ernst & Young (EY) to evaluate whether the wildfire mitigation costs for which we seek recovery were booked to the appropriate memorandum accounts and were for activities that were incremental to those contemplated by rates established in the GRC and other recovery mechanisms. Section D of this chapter describes EY's audit, which reviewed PG&E's recorded costs in question and confirmed that the wildfire mitigation costs are incremental and appropriately categorized.

Finally, based on lessons learned from prior filings, we have attempted to respond to questions intervenors may raise regarding the Company's methodologies for ensuring incrementality. Section E addresses these potential questions.

B. The Costs for Which PG&E Seeks Recovery Are Incremental

In 2019 our Electric Distribution Organization performed substantially more work than was forecasted in our 2017 GRC. We executed approximately 2,200,000 hours of work above the 2019 Electric Distribution work plan (~50 percent) due to the volume of 2019 major event responses, as well as reliability, pole replacement, and maintenance work. These hours represent an additional 1,650,000 hours of work as compared to 2018 work execution levels (~25%). While the work performed by these incremental hours does not strictly correspond to the activities reflected in this application, the comparison of 2019 actuals to 2019 plan and 2019 actuals to 2018 actuals demonstrates the magnitude—overall—of the incremental work performed in 2019.

Our wildfire mitigation and catastrophic event work comprised a significant part of this story. As described below, the costs presented in this application are incremental to those recovered by PG&E through our GRC and other mechanisms, and we separately track these costs to ensure that they are not double-recovered.

1. Overview of PG&E's Activity-Based Forecasting

The wildfire and CEMA costs for which we seek recovery in this application were not included in PG&E's 2017 GRC forecast. The following section describes our activity-based methodology for forecasting and recording costs for recovery through rates, which is foundational to the incrementality of the activities for which we seek recover in this application.

The recovery mechanism for a particular PG&E activity is determined by the activity scope. Activity-based forecasts create cost estimates, scopes, and schedules for work which are not tied to particular departments or staff.[2] As an example, we forecast asset maintenance activities based on the anticipated volume and complexity of work that is required to safely maintain the system in compliance with established policies and requirements. At the time the forecast is created, the resources to execute the work are not specified. The maintenance work is either completed with internal PG&E employees or contracted vendors, and the forecasted cost does not include internal employee salaries. The resources to complete the work ultimately are assigned closer in time to the execution of the work.

PG&E's forecasts typically present an aggregate cost for an activity without capturing the specific components of cost, labor, overheads, materials, etc. PG&E's headcount and support functions are not captured

2 For repeatable types of work, this forecasting process is tied to projecting total unit volumes and using a unit cost estimate to develop the financial forecast. The forecast typically does not specify whether internal or external resources will execute the work.

by any particular recovery mechanism, such as the GRC. Moreover, PG&E's methodology for forecasting is not so granular that materials or distinct allocations are explicitly identified in the forecast.

We use an activity-based forecast to ensure proper cost recovery through the appropriate mechanism. Our forecasts are not associated with specific employees or departments; instead they are based upon volumes of work, regardless of how the work is executed or by whom. Because PG&E staff and organizations often support work across multiple rate cases and regulatory accounts, this methodology provides flexibility to use internal and external resources as necessary to execute the work.

2. CEMA: Historic Costs are Excluded from GRC Forecasts

PG&E recovers base operating costs in our GRCs. Base operating costs include emergency response costs not eligible for recovery through the established CEMA mechanism. As a result, PG&E's GRCs are intended to recover costs from "major" emergencies, but PG&E's CEMA applications are intended to recover costs from "catastrophic events," which are those for which a disaster has been declared by the state or federal government.

In our GRC, PG&E first forecasts the cost of work performed for "major" emergencies. These costs are forecast on a fully loaded basis—i.e., the costs include both direct and overhead costs. For example, in our 2017 GRC, this forecast was based on the 5-year average (2010-2014) of historical costs. We then adjust (reduce) these forecast costs (on a fully loaded basis) for our forecast of CEMA costs, which is based on the 5-year average of CEMA-related costs for both direct and overhead expenditures. Therefore, our GRC revenue request for major emergency work does not include any work or costs (including straight time labor and overhead allocations) for CEMA events. This process also applies to the cost recovery true-up of the Major Emergency Balancing Account (MEBA) at the end of each year for electric distribution.

Because no CEMA costs are included in our GRC forecast submission, balancing account true-up, or other recovery mechanisms, a CEMA application represents the only mechanism for PG&E to collect costs recorded in CEMA event response orders. All CEMA work and all associated overheads costs can thus exclusively be recovered through a CEMA application.[3]

Major event responses (whether for CEMA or non-CEMA events) require PG&E resources across various departments to respond to outages and public safety situations with little to no-lead time. This fundamentally changes the Company's regular processes for executing base work because PG&E resources must temporarily delay base work in order to respond rapidly to urgent events.

"Routine" emergency work is also included in our GRC filing, and reflects smaller scale restoration and facility repair work that does not meet the major emergency or declared disaster thresholds. This work is funded as a part of our GRC and does not get trued-up via the MEBA recovery process. CEMA work does not get captured in the corresponding Major Work Categories (MWC) for "Routine" Emergency work and as such does not overlap with GRC funding.

a. Gas Distribution – GRC Base Rates Versus CEMA Work

Costs for Gas Distribution emergency response are recovered through GRC base rates. Gas Distribution Emergency Response includes work and materials required to replace damaged or failed facilities and are captured under MWC 52—Gas Distribution Emergency Response, and MWC FI—Corrective Maintenance, 1 for example, among others. This includes the replacement or repairs of mains, services, and regulator stations due to gas dig-ins and external forces such as landslides and non-catastrophic earth movements. However, Gas Distribution does not forecast for catastrophic events given the unpredictability of such events.

As with Electric Distribution, once an emergency is formally declared, PG&E creates specially coded and titled orders to allow the event response costs to be clearly and automatically segregated from routine work of the same type for CEMA tracking. Because these costs are not forecast as part of the GRC, therefore, all activity related to

[3] This process was described in PG&E's 2017 GRC application, Exhibit (PG&E-4), Chapter 4, p. 4-20.

CEMA events is unique and incremental to normal cost recovery mechanisms.

b. Power Generation – GRC Base Rates Versus CEMA Work

Power Generation does not forecast in its GRC for catastrophic events given the unpredictability of such events. As with Electric and Gas Distribution, once an emergency is formally declared, PG&E creates specially coded and titled orders to allow the event response costs to be clearly and automatically segregated from routine work for CEMA tracking. Because these costs are not forecast as part of the GRC, all activity related to CEMA events is unique and incremental to GRC-related costs.

3. Wildfire Mitigation: Work Comprised of New Activities and New Volumes of Work

a. Incremental Memorandum Accounts

Our wildfire mitigation work described in this application consists of activities booked to the FHPMA and activities conducted as part of PG&E's 2019 WMP and booked to the FRMMA or WMPMA.

FHPMA: In response to southern California wildfires in 2007, the CPUC initiated R.08-11-005, in which it adopted regulations to protect the public from potential fire hazards associated with overhead power lines. Beginning in 2009, the CPUC issued several decisions in this proceeding that adopted various new fire safety regulations, including General Order (GO) 166, Standard 1.E., which required electric utilities with overhead facilities in high fire-threat areas subject to extreme fire-weather events to prepare an annual fire prevention plan.

In May 2015, the CPUC initiated a successor to R.08-11-005, R.15-05-006, which addressed the following: (1) the development and adoption of a statewide fire-threat map that delineates the boundaries of new High Fire-Threat Districts (HFTD) where the newly-adopted regulations would apply; (2) the determination of the need for additional fire-safety regulations in HFTD areas; and (3) the revision of GO 95 to include a definition and maps of the HFTD areas, as well as new fire-safety regulations.

Some of the costs recorded to the FHPMA are also related to our compliance with CPUC D.17-12-024, which created new tree radial clearance standards and addressed the implementation of amendments to GO 95.

The FHPMA is used to track and record incremental costs associated with the implementation of regulations and requirements that have not been authorized for recovery in PG&E's GRC or other regulatory proceedings. Work booked to the FHPMA was generally conducted from 2012-2018.

FRMMA and WMPMA: Following recent devastating wildfires in California, the Legislature passed SB 901, which called for utilities to create a Wildfire Mitigation Plan (WMP). Mitigation work performed pursuant to our 2019 WMP for which recovery is sought here was tracked in the FRMMA or WMPMA and the work generally occurred in 2019.

As part of our 2019 WMP, we have instituted new programs, activities, and increased work volumes, which are incremental and not part of the GRC or any other rate case. The 2017 GRC, which covers 2017-2019, used 2014 recorded amounts as the "base year" and was filed in 2015 before we substantially reassessed our wildfire mitigation work in 2018.

b. Wildfire Mitigation Incrementality Types

Costs for each of the work categories included in this application are incremental to the amounts recovered in customer rates in 2017-2019 authorized by the 2017 GRC Decision on one of the following bases.

1) New Activities

Wildfire events in 2017 and 2018, and legislation implemented in response to them, led us to implement new programs that were neither contemplated by nor part of our requests in the 2017 GRC.

2) Increased Work Volumes

Developments in 2017 and 2018 led us to expand significantly programs that were originally included in the 2017 GRC Decision. For example, some programs saw a dramatic increase in units of work completed over adopted amounts. This application seeks recovery for only costs of the incremental work completed above and beyond what was specifically authorized in or imputed from the 2017 GRC Decision.

4. Other Types of Costs: The LCPIA and RRRMA Work Has Been Tracked for Many Years Outside the GRC

In addition to the CEMA and Wildfire costs discussed above at length, this application also includes costs related to the Land Conservation Commitment and Residential Rate Reform. The former is presented in Chapter 5 of the accompanying testimony. The latter is presented in Chapter 7 of the accompanying testimony.

Land Conservation Plan Implementation Account (LCPIA): Commission Resolution E-4072 (May 3, 2007) authorizes PG&E to separately record our costs to process applications before the CPUC or the Federal Energy Regulatory Commission (FERC) on transactions necessary to implement the Land Conservation Plan approved in D.03-12-035. The Land Conservation Plan was established as part of PG&E's emergence from bankruptcy in 2003. The name of the account used to record these costs is the Land Conservation Plan Implementation Account, referred to as the LCPIA.

The costs recorded in the LCPIA that are sought in this application date back to 2011. These costs have not been forecasted in GRCs and thus are not in PG&E's base revenues.

Residential Rate Reform Memorandum Account (RRRMA): As explained in Chapter 7, PG&E's 2017 GRC decision provided for separate tracking of costs and collection of revenues for implementing residential rate reform during 2017-2019. This construct thus separated and segregated the revenue and spending for residential rate reform activities over the 2017-2019 period.

Under the 2017 GRC Decision, the Commission authorized PG&E to collect $19.3 million per year of the three-year rate case cycle (for a cumulative total of $57.9 million) and to record our corresponding costs in the RRRMA.

We underspent the total revenue requirement for this period by approximately $3.7 million and have included in this application a refund of that amount for customers. Chapter 7 describes the entirety of PG&E's spending recorded to the RRRMA over the applicable period.

C. Orders and Financial Tracking

To adhere to the activity-based forecasting methodology described above, and to ensure that Wildfire mitigation costs are properly accounted for, all costs for which we seek recovery in this application were tracked in distinct orders that were tagged with identifiers different from those that are included in our GRC or other cost recovery mechanisms. Accordingly, this application is the appropriate mechanism to recover costs incurred for the events and work described herein. This is applicable to all costs incurred, and, as such, all costs captured in these orders are incremental to other recovery mechanisms' revenues.

All PG&E orders are linked to distinct regulatory filings. The costs and forecasts for activities associated with the GRC are only included in the GRC filing process, and, similarly, the costs and forecasts for activities associated with this filing are only included in the filing process for this application. Because of this linkage, any forecasted or recorded cost is addressed through a single regulatory process. This distinct order-tracking methodology ensures that duplicative recovery is avoided. Consequently, all costs captured in orders linked to this application are incremental and distinct from costs incurred and reviewed via the GRC or other rate case filings.

1. MEBA and CEMA – Electric Distribution Specific Order Process

CEMA was created to provide recovery for costs incurred in response to catastrophic events. Not all major, emergency, or rapid response events are CEMA-eligible. To be classified as a CEMA-eligible event, an emergency declaration from the Governor of California or President of the United States is required.

In the hours or days prior to an emergency declaration, PG&E follows specified accounting procedures and, for electric distribution, typically begins recording emergency response costs to the MEBA.[4] Once an event is classified as a catastrophic event, PG&E removes from MEBA the fully loaded costs for the electric distribution work performed and records them to CEMA. The following paragraphs describe this process more fully for electric distribution.

PG&E follows specific procedures for recording expenditures associated with the response and repair of damage to Company facilities. During the occurrence of a major event, affected divisions each separately track and report the costs incurred for restoring utility service and repairing damaged facilities associated with that event. The divisions segregate these costs by creating "specific orders"[5] to capture repair, replacement, and service restoration costs. These specific orders are created for both capital and expense and for overhead and underground restoration work, by county, within each division. PG&E creates the orders using a specific naming convention to identify the business region, division, county, and event for which the order is created.

The Finance Section Chief within the Operations Emergency Center or the Incident Management Team is responsible for monitoring costs, developing financial accounting strategy and providing charging guidance during the event. Costs are closely monitored and reviewed to ensure they are recorded in the correct Major Work Category (MWC) and aligned with the correct line of business (LOB). Where an event affects multiple PG&E facilities across systemwide geographic regions, multiple specific orders are

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4 The CPUC approved PG&E's MEBA in PG&E's 2014 GRC D.14-08-032. The purpose of the MEBA is to recover actual expenses and capital revenue requirements resulting from responding to major emergencies and catastrophic events not eligible for recovery through CEMA, which only records costs related to declared emergencies. To effectively separate and remove CEMA qualifying costs from MEBA, CEMA qualifying orders are identified and reassigned to a dedicated Receiver Cost Center that is established to track and separate CEMA costs. The costs requested for recovery in this application are excluded from PG&E's MEBA and, for that matter, all non-CEMA regulatory forecasts.

5 A "specific order" is a term used in PG&E's SAP accounting system to refer to orders established to record costs related to particular tasks or a given scope of work. Once the tasks or projects are complete, the specific orders are closed. These specific orders differ from "standing orders." Standing orders are used to record costs for day-to-day ongoing utility operations and are not closed following completion of specific tasks or projects.

used to ensure the proper reporting and control of system repairs and restoration work. PG&E's Business Finance Department, Emergency Recovery Program Manager, and the affected divisions review the orders to ensure that the costs charged to the specific orders occurred within the timeframes of the event, are in accordance with the major event charging guidelines, and were in the correct counties covered by the orders.

When a state or federal authority declares an emergency, we can identify clearly the CEMA-eligible portion of a declared event's costs and ensure there is no overlap between CEMA orders and GRC-funded orders.

2. Tracking Wildfire Mitigation Costs

Wildfire mitigation costs consist of two categories of incrementality: New activities and increased work volumes. These are tracked as described below.

a. New Activity

PG&E's base funded GRC work does not includes costs for new programs such as System Hardening, Public Safety Power Shut-off, and Enhanced Vegetation Management.[6] PG&E tagged all orders created for these activities with a Balancing/Memorandum Account Receiver Cost Center that identifies the costs as incremental wildfire mitigation. In addition, PG&E tagged all orders with a Master Funding ID (MFID) that indicates the recovery mechanism. GRC activities, in contrast, are tagged with a GRC MFID.

b. Incremental Work Volume

PG&E's base-funded GRC work includes wildfire-related work, but the costs for which we request recovery in this application are for additional work beyond what was authorized in the GRC.

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6 Enhanced Vegetation Management qualitatively differs from PG&E's routine, or baseline, vegetation management activities. It is more aggressive, and in addition to, routine practices with respect to overhead clearing, clearing of trees with the potential to strike equipment, targeted tree species work, wood removal, and safety oversight. In addition, in January 2018, the CPUC adopted the HFTD Map, which drastically increased the amount of PG&E's service area classified as "high fire threat area," where stricter fire-safety regulations apply, corresponding to increased clearance requirements.

PG&E's GRC funds baseline work, which has been supplemented significantly to address wildfire risks. To ensure incrementality in these areas, PG&E tracks wildfire mitigation-eligible costs in separate orders and GRC base-funded activities are removed.

The GRC base-funded activity level is determined by evaluating the GRC forecast and Decision. If a precise level of activity was forecast and approved in the GRC, that level is considered to be the base-funded activity level. If no precise level of activity was forecast or approved, a historic average of the activity level is used as the base-funded level.

The costs for which we seek recovery in this application fall into these categories of incrementality as described in the following table:

TABLE 8-1
INCREMENTALITY RATIONALE FOR WILDFIRE MITIGATION COSTS

Section	Mitigation	Incrementality
2-B.1.a	Overhead non-pole replacement	**Increased Spending over GRC:** The work for which PG&E seeks recovery under this program was in addition to the $6.363 million contemplated by the rates authorized in PG&E's 2017 GRC
2-B.1.a	Deteriorated Pole Replacement	**Increased Spending over GRC:** The work for which PG&E seeks recovery under this program was in addition to the $6.452 million contemplated by the rates authorized in PG&E's 2017 GRC
2-B.1.a	Routine Emergency Replacement	**Increased Spending over GRC:** The work for which PG&E seeks recovery under this program was in addition to the $0.952 million contemplated by the rates authorized in PG&E's 2017 GRC
2-B.1.a	Idle Facilities Removal	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.1.b	Substation Rep	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.1.b	Substation Def Space	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.1.b	Substation Anmial Abate & Emerg E	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.2.a	Overhead System Hardening	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.2.a	Pole Replacement	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.2.a	Covered Conductor	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.2.a	Undergrounding	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.2.a	Removal of Overhead Lines	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.2.b	Granular Sectionalizing (PSPS)	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.2.b	Automation and Protection (SCADA	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.2.c	Replacement of Non Exempt Fuses	**Increased Units:** The work for which PG&E seeks recovery under this program was in addition to the 50 units contemplated by the rates authorized in PG&E's 2017 GRC
2-B.2.c	Resilience Zones/Microgrids	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.

TABLE 8-1
INCREMENTALITY RATIONALE FOR WILDFIRE MITIGATION COSTS
(CONTINUED)

Section	Mitigation	Incrementality
2-B.3.b	Climatology	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.3.b	Geographic Information Systems	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.3.b	REAX	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.3.c	Increased Ispections and Associated Tree Work in HFTD Areas	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.3.d	Fuel Reduction	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.3.d	Accel Wildfire Risk Reduction	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.3.d	Enhanced Veg Mgmt Prog	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.4.a	Community Wildfire Safety Program PMO	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.4.b	Expanded Weather Station Deployn	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.4.b	Wildfire Cameras	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.4.b	Sensor IQ	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.4.c	Advanced Fire Modeling	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.4.c	Wind Loading	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.4.d	Wildfire Safety Operations Center	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.4.e	Safety and Information Protection T	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.4.e	SmartMeter Partial Voltage Detecti	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
2-B.5	Public Safety Power Shutoffs	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
4	Power Gen	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.
5	IT	**New Activity:** This program was instituted after, and was incremental to work included in, rates authorized in PG&E's 2017 GRC.

As shown in this table, four of the work categories for which we seek recovery are incremental because we performed incremental units of work or spent incrementally more in dollars than were contemplated in our 2017 GRC Decision. These categories are:

1) Non-Exempt Equipment Replacement (Fuses)

Replacement of Non-Exempt Equipment refers to the replacement of existing primary line equipment such as fuses and cutouts with equipment that has been certified by CAL FIRE as low fire risk and therefore exempt from vegetation clearance. This replacement work eliminates overhead line equipment and devices that may generate exposed electrical arcs, sparks or hot material during their operation. In the 2017 GRC, PG&E forecasted 50 units for a total cost of $0.5 million to do that routine work. In 2018, we significantly expanded the program and replaced 807 fuses. In this application, we request recovery of $9.1 million as the incremental amount.

2) Overhead Replacement, Pole Replacements, and Routine Emergency Replacement

This work refers to the identification and replacement of broken, damaged, or decayed distribution equipment, including conductors, connectors, crossarms, insulators, transformers, and poles. In our 2017 GRC, PG&E forecasted $13.8 million in capital expenditures for this equipment replacement in 2019 for Tier 2 and 3 HFTD areas. Because of our more aggressive wildfire mitigation measures in our 2019 WMP, PG&E incurred $223.3 million in capital expenditures for this work in 2019 for tier 2 and 3 HFTD areas. We seek recovery for the incremental amount of $209.5 million in this application.

D. Ernst & Young's (EY) Independent Audit Report

1. Description of EY's Audit

We proactively engaged EY to review the wildfire mitigation costs in this application. EY evaluated whether the costs were booked to the appropriate memorandum accounts and were for activities that were incremental to those contemplated by rates established in the GRC.[7]

EY's review included costs booked to the FHPMA, FRMMA, and WMPMA for which we seek recovery in this application. EY reviewed costs associated with contractor expenses, materials, internal labor and associated overheads to confirm that these costs were incremental to amounts authorized in D.17-05-013 in PG&E's 2017 GRC. EY adhered to PG&E's incrementality definition for this work, which is: Costs are incremental if incurred for work that was not funded in our GRC (because it is in addition to or separate from GRC costs) or any other recovery mechanism or proceeding.

EY further evaluated whether the wildfire mitigation costs were properly recorded in the FHPMA, the FRMMA, and the WMPMA. EY evaluated whether costs recorded in these accounts were incurred for separate activities—that is, whether costs are recovered in multiple accounts. EY tested transactions and selected representative samples to determine whether the costs had appropriate underlying support.

During EY's transactional testing for vendor costs, EY reviewed documentation and spoke with Company personnel to understand other available recovery mechanisms for wildfire and catastrophic event-type activities such as CEMA. EY evaluated transactions with a view to the characteristics of various recovery mechanisms in order to identify potentially misclassified transactions in the memorandum accounts. EY flagged transactions identified as potentially recoverable in other accounts. EY then obtained from PG&E further information to support inclusion of these transactions in the memorandum accounts as described in this application.

EY conducted its analysis in accordance with consulting standards established by the American Institute of Certified Public Accountants. EY's approach was designed to achieve (to the extent possible given the scope of

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7 EY's review was not an audit, review or compilation as those terms are defined by the American Institute of Certified Public Accountants.

this work) the principles of the National Association of Regulatory Utility Commissions audit manual.

2. EY's Review Methodology and Observations

EY segregated the costs within the memorandum accounts by cost category and developed testing procedures for each category of costs based on the unique nature and risks of each cost category. The table below summarizes the cost categories:

TABLE 8-2
POPULATION OF MEMORANDUM ACCOUNTS BY COST CATEGORY

Line No.	Cost Category	Amount
1	Vendor (Vendor Key, i.e. not null)	$1,301,879,235
2	Accruals, Reserves, and Other	203,754,152
3	Internal Labor (PGE1/660)	140,303,017
4	Materials (PGE1/53)	43,792,338
5	Overheads (PGE1/601)	238,740,468
6	Employee Expenses (Vendor Key "U")	5,849,899
7	Total	$1,934,319,109

We provided to EY available data and supporting documentation for each of these cost categories. EY then reviewed the support for the cost categories as follows:

Vendor Costs: EY performed detailed transaction testing on approximately $357 million of vendor costs (27% of total vendor costs).[8]

- EY isolated costs incurred for work performed by the single largest vendor (totaling approximately $220 million) and performed separate procedures due to the material amount of the collective charges. EY performed an analysis of this vendor's charges by date, order, and amount. EY selected targeted transactions upon which to perform detailed substantive testing, including analyzing underlying invoices, contracts, and purchase orders.[9]
- EY collected invoices for other high dollar transactions (totaling approximately $216 million) and tested a targeted selection of them. EY

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[8] EY Report, pp. 7-8.

[9] EY Report, pp. 7-15.

traced these transactions from the invoice back to the financial records. This testing included the analyzation of invoices, contracts, purchase orders, and other potentially relevant contemporaneous information.[10]

- EY performed a statistical sample of the remaining vendor costs (totally approximately $866 million) and tested transactions from the financial records to supporting invoices and contracts.[11]

Accruals, Reserves and Other: EY tested a targeted selection of cost accruals (approximately $204 million) by collecting available invoices and performed cut-off testing related to the timing of the accrual entry. EY also analyzed the accrual estimate for reasonableness as compared to final invoiced costs.[12]

Internal Labor: EY performed analytics over the entire population (approximately $140 million) of internal PG&E labor costs to identify unusual items based on date, hours charged per day and rate per hour, and transactions lacking consistent attributes of other internal labor items. EY selected transactions for further testing that were identified through these analytics.[13]

Materials: EY performed analytics over the entire population (approximately $44 million) of material cost to identify unusual items based on date and rate per unit. EY selected transactions for further testing that were identified through these analytics.[14]

Overheads: EY performed analytics over the entire population (approximately $239 million) of overhead charges. Based on these analytics EY selected overhead charges for recalculation totaling $93 million.[15]

Employee Expenses: EY selected a sample of employee expenses (approximately $5.8 million) through statistical sampling and traced the expenses back to financial records and supporting documentation. EY also

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10 EY Report, pp. 7-15.

11 EY Report, pp. 7-15.

12 EY Report, pp. 15-17.

13 EY Report, pp. 17-20.

14 EY Report, pp. 20-21.

15 EY Report, pp. 22-24.

ran analytics across the employee expense population as compared to the internal labor population to consider whether employees submitting expenses had evidenced worked on memorandum account activity.[16]

Capital/Expense: For transactions recorded as capital, EY consulted PG&E's capitalization policy and retirement unit guidelines to consider whether there was sufficient evidence for the capitalization of a transaction.[17]

In addition to the analysis and transaction testing described above, EY considered the incrementality of these costs in totality as compared to PG&E's 2017 GRC. EY reviewed PG&E's 2017 GRC application and supporting work papers to understand the type and nature of costs included within current base rates. EY then compared those costs and activities to the in-scope memorandum accounts to identify potential overlap or risk of double recovery. Furthermore, EY considered the imputed GRC costs for 2019 as compared to 2019 total actual incurred costs to identify large or unusual movements that may be indicative of GRC items being recorded in the memorandum accounts.[18]

3. Results of EY's Review

EY prepared findings and observations regarding the costs in the memorandum accounts based on EY's testing and analyses. EY's report is provided as Attachment A to this testimony. In summary, EY identified no issues that materially affect the balances of the memorandum accounts.[19] Aside from the comments summarized below, EY found no evidence to contradict PG&E's conclusions that the costs were: (i) incurred for activities within the scope of the relevant CPUC-approved memorandum account (the FHPMA, FRMMA, or WMPMA); (ii) accurately recorded; and (iii) incremental.[20]

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16 EY Report, pp. 24-25.

17 EY Report, pp. 14-15.

18 EY Report, pp. 25-28.

19 EY Report, pp. 7, 29.

20 EY Report, pp. 7, 29.

EY identified items totaling approximately $2.9 million (extrapolated to approximately $6.2 million) that were not properly evidenced for inclusion in the memorandum accounts.[21] EY's observations are summarizes as follows:

Unsupported vendor expenses: EY noted limited instances of vendors that charged amounts that were not supported by an invoice, contract, or purchase order. These items included unsubstantiated *per diem* amounts, inconsistent treatment of hotel charges, labor expense inconsistencies, and unsubstantiated miscellaneous expenses. EY also noted limited instances of vendors marking up subcontractor charges in a manner that was prohibited by the contract. EY noted limited instances in which a vendor contracted by PG&E for a specific service simultaneously worked as a subcontractor (subject to a markup) for a different service.[22]

Internal Labor: EY noted limited instances where internal labor charges were premised on rates of $175 or more per hour related to Management Services and Contractor Administration costs. EY was unable to identify supporting detail for these rates, which were atypically high for this work. EY also noted limited instances of internal labor charges related to Nuclear or Generation employees for which EY was unable to identify support for allocation to the FRMMA.[23]

Overhead: EY was unable to identify support for allocation to the memorandum accounts of Nuclear Generation overheads of approximately $76,000.[24]

Employee Expense: EY was unable to identify supporting labor documentation for expenses of approximately $234,000 for employees that should have had accompanying labor hours.[25]

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[21] EY Report, p. 29.

[22] EY Report, p. 29.

[23] EY Report, pp. 29-30.

[24] EY Report, p. 30.

[25] EY Report, p. 30.

Transactions recorded in the wrong account: EY noted limited instances in which amounts recorded in the FRMMA should have been recorded in FHPMA.[26]

TABLE 8-3
OBSERVATIONS FOR POTENTIAL EXCLUSIONS

Line No.	Cost Category	Exclusion Type	Statistical Sample	Targeted Selections	Total
1	Vendor	Idled Equipment	–	$17,487	$17,487
2	Vendor	Labor	34,025	124,168	158,194
3	Vendor	Lodging	–	153,106	153,106
4	Vendor	Markup	284,859	321,320	606,179
5	Vendor	Materials & supplies	4,735	118,344	123,079
6	Vendor	Per diem	115,163	456,655	571,818
7	Vendor	Travel expense	2,213	41,241	43,454
8	Vendor	Vehicle	97,297	762,250	859,546
9	Internal Labor	Rate > $200 per hour	–	7,366	7,366
10	Internal Labor	Nuc/Gen	–	13,955	13,955
11	Overhead	Nuc/Gen	–	76,260	76,260
12	Employee Expenses	Type A Employee	–	233,910	233,910
13	Total		$538,292	$2,326,062	$2,864,354
14	Total - Extrapolated		$3,862,334	$2,326,062	$6,188,396

As a result of EY's observations, we removed these costs from our request. See chapter 9 for this discussion. Note that the costs removed were $6.7 million, which was an earlier estimate of the findings that was needed for the RO run. This will be updated at a future iteration of the RO run.

E. Intervenors' Historic Concerns About Incrementality Have Been Addressed

In prior PG&E CEMA application proceedings, intervenors have raised certain incrementality concerns about the types of costs presented by PG&E, such as "straight-time labor," "materials," and "overheads." These historic concerns are addressed below. Additionally, the last section discusses how event response costs are moved from MEBA to CEMA once an emergency is declared.

26 EY Report, p.7.

1. Straight-Time Labor

Historically, intervenors have argued against the recovery of straight-time labor through the CEMA filing due to the incorrect assumption that straight-time labor is already funded via base rates. As noted above, however, the GRC and GT&S Rate Case include forecast costs based on activities, not specific people or positions. Those activity-based forecasts—which are reduced to remove the costs of CEMA activities—take into account various cost components like the replacement assets and tools, and labor rates, which include a combination of straight-time, overtime, and double-time labor. Had CEMA activities been included, the forecasts would have been higher. Accordingly, cost components associated with CEMA activities, including CEMA straight-time labor costs, are incremental to base rates.

When a CEMA-eligible event occurs, PG&E may have to deprioritize non-event response work to devote as many resources as possible to repair damaged electric and gas facilities and restore service as quickly as possible. In performing this work, PG&E crews often work around the clock, incurring not only straight-time, but also overtime and double-time labor costs. These costs are booked to the specific orders using the process described in the previous section and in Chapters 4 and 5.

Once the repair and restoration activities have concluded, PG&E crews return to their routine duties, including activities that had been postponed due to the CEMA eligible event. Completing the postponed activities requires incremental overtime labor as well as significant incremental contract resources to offset resources diverted to the event response work.[27] Yet, PG&E does not rely on a quantification of those incremental costs to serve as a proxy for CEMA straight-time labor. They are not charged to CEMA specific orders, but rather are incurred to replace the

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27 Major event response has a multitude of downstream ripple effects on displaced work that can be difficult and costly to track. For example, if a catastrophic storm pushes out a routine project by one week, that project will be rescheduled to the following available construction window. The project will then displace *other* work that will *itself* require rescheduling, potentially displacing additional work.

labor (straight-time and overtime) originally intended for executing base work.[28]

Hence, the test of incrementality is not whether a cost is straight-time or overtime. If that were the test, PG&E would book overtime costs to CEMA specific orders for work unrelated to the catastrophic event such as incremental overtime required for reprioritized base work. Similarly, PG&E would exclude from CEMA specific orders costs directly related to a catastrophic event only because the costs were incurred during normal working hours. PG&E does neither. CEMA straight-time labor is incremental for the simple reason that the GRC and GT&S forecasts are reduced commensurate with the cost of CEMA activities.

2. Materials

Similarly, some intervenors have historically argued for the exclusion of routine material costs. PG&E has two methods for accounting for what it spends on materials; these methods are used both for normal work and emergency response activities.

Small, common material items (e.g., small bolts, screws, nails) are kept as common stock in work locations and the cost for these materials are spread to orders through an allocation to work categories that use these materials. Major events do not receive the allocation for common stock items, so those material costs are not included in this application for cost recovery, though one could argue they should be as they are used during CEMA events.

Larger pieces of equipment (e.g., poles, transformers, and cable) are directly charged to specific work orders as that material is used on a given job. During major events, PG&E may proactively bring major materials to local yards or base camps that are temporarily established to facilitate restoration. The cost for these materials staged for major events are only charged to the emergency orders (including CEMA-specific orders) once a specific piece of material has been used on a specific job. The only material

28 We never have sought cost recovery for incremental overtime labor and contracting to address base work due to a CEMA event.

charges included in this application are directly tied to CEMA event response work.

Any material used during a catastrophic event must be restocked by PG&E to provide material to execute the base work that was temporarily deferred to address the event. Any items pulled from inventory for an event are repurchased. PG&E sets minimum inventory levels for commonly used materials. As that material is used, there is a trigger to automatically repurchase the specific item once it has dropped below a specific inventory level. As such, any material used during event response is ultimately restocked; all material used in CEMA event response is incremental to base material spend.

3. Overhead Costs

Intervenors have historically argued that most or all overheads are fully funded by base rates because PG&E uses our existing facilities, fleets, staff, etc. when performing CEMA emergency work. This argument assumes incorrectly that PG&E equipment and resources, including overheads, are funded through a single cost-recovery mechanism. CEMA costs in particular are removed from GRC and GT&S forecasts and are therefore excluded from the rates authorized in those cases. Moreover, PG&E incurs incremental costs for CEMA work beyond those associated with GRC and GT&S activities for certain overheads including payroll taxes, fleet, and IT devices. Because PG&E has not recovered the full cost of our equipment and resources in the GRC or GT&S, it is appropriate to recover the portion of the cost attributable to CEMA in this proceeding.

PG&E applies overheads to the labor and materials in all of our capital and balancing account orders so that the orders reflect the full costs of the work being performed.[29] Each overhead corresponds to a rate that is calculated to apply costs proportionately and consistently to either labor or materials in accordance with the guiding principles and requirements of the

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29 The overheads applied to labor include: benefits; paid time off; building services; Information Technology device services; fleet; indirect labor; payroll taxes; and operational management and support. The overheads applied to materials include: material burden and minor materials. As discussed in Chapter 5, PG&E has excluded from this CEMA request certain overhead costs that relate to employee benefits and capitalized Administrative and General.

FERC Uniform System of Accounts. Most overheads are calculated on a companywide basis. To determine the applicable rate, the total Company cost of the overhead is divided by the total company cost of labor or materials. In some cases where the use or consumption of overhead services are not uniform across the LOBs, separate LOB overhead rates are calculated.

For purposes of calculating overhead rates, PG&E combines a forecast for labor and materials associated with all base work, CEMA-eligible emergency work (based on a 5-year historical average of past CEMA expenditures), and PG&E's forecast of non-CEMA emergency work (i.e., routine emergency and MEBA work). Through this calculation, the total company costs of the overhead are allocated between CEMA, non-CEMA emergency, and all base work so as to proportionately spread the employee-related components of these costs across all activities that require PG&E staffing labor in a manner commensurate with the level of staff activity. CEMA events incur PG&E staff labor and as such, they necessarily incur overhead costs associated with PG&E staff.

As a result, when PG&E excludes CEMA-eligible emergency work from our GT&S or GRC forecast, we exclude not just the base cost of labor and materials associated with that work, but all associated overhead costs. This is true regardless of whether PG&E hires additional staff or acquires new vehicles to perform CEMA work. Stated another way, PG&E does not seek the full extent of our overhead costs through the GRC or GT&S because we have allocated a portion of these overheads to CEMA applications and other regulatory filings (i.e., the FERC TO filing).

Additionally, as more labor costs are incurred in response to a catastrophic event, variable costs within several overhead categories also increase. For example, the fleet overhead includes costs to maintain and repair PG&E vehicles, fuel costs, and rental equipment costs. In response to CEMA events, additional fuel costs and rental equipment costs are incurred. Vehicle maintenance and repair costs may also increase, resulting from additional wear and tear on the vehicles deployed in response to the CEMA events. Similarly, the payroll tax overhead includes payroll taxes incurred by the Company, which increase when additional overtime or double-time hours are incurred as a result of employees working on a CEMA event.

Following significant CEMA events, such as those represented in this application, PG&E automatically adjusts future GRC or GT&S overhead cost forecasts on the assumption that costs will be recovered via CEMA applications.[30]

F. Conclusion

This chapter demonstrates that the costs requested in this application are incremental. The costs for which we seek recovery in this application are for activities that are different from and in addition to those forecast in our GRC, GT&S, and other cost recovery mechanisms. We have tracked these costs separately and only those incremental costs are requested in this application. The costs therefore are eligible for recovery in this application.

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30 To simplify the review process, we are consolidating a number of overheads, including overheads related to CEMA, beginning in its 2020 GRC forecast on a going forward basis. However, that change was not yet implemented in PG&E's 2017 GRC, which set the rates in effect for the years in which the CEMA costs at issue in this application were incurred.

PACIFIC GAS AND ELECTRIC COMPANY

2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS

CHAPTER 8

ATTACHMENT A

ERNST & YOUNG COST ANALYSIS

Pacific Gas & Electric

Wildfire Mitigation and Catastrophic Events Cost Analysis

September 2020

Building a better working world

Building a better working world

September 25, 2020

Pacific Gas & Electric

77 Beale Street
San Francisco, CA 94105

Matthew Whorton:

We have completed our analysis of the costs recorded in the accounts listed below to support Pacific Gas and Electric Company's ("PG&E" or "the Company") Wildfire Mitigation and Catastrophic Events Cost Recovery Application. Our procedures were performed in accordance with our Statement of Work, dated May 20, 2020. We analyzed the Wildfire Mitigation Plan Memorandum Account (WMPMA), Fire Risk Mitigation Memorandum Account (FRMMA) and Fire Hazard Prevention Memorandum Account (FHPMA) to determine whether PG&E's recorded costs were properly recorded and reported in PG&E's application and incremental to costs previously authorized or requested for recovery.

Our report consists of three parts:

- We summarize our scope, approach and findings in a narrative executive summary;
- We describe our testing procedures and detailed observations in the body of the report; and
- We conclude with our summary of findings and recommendations for potential exclusions.

The information provided in this report is intended to be used to support the Company's Wildfire Mitigation and Catastrophic Events Cost Recovery application that will be filed later this year with the California Public Utilities Commission ("CPUC"). The report is not intended to be, and should not be, used without our prior written consent by any other party or for any other purpose. Our calculations relied on underlying accounting information provided by the Company. We did not audit that underlying accounting information.

We would be pleased to discuss any aspect of our work or this report with you or other members of management at your convenience.

Thank you,

Ernst & Young LLP

Table of Contents

I. Introduction

Pacific Gas & Electric Company (the "Company" or "PG&E") engaged Ernst & Young LLP ("EY") to conduct an analysis of costs included in PG&E's Wildfire Mitigation and Catastrophic Events Cost Recovery Application. The accounts included within the scope of work for this analysis are: Wildfire Mitigation Plan Memorandum Account ("WMPMA") from 6/5/2019 through 12/31/2019, Fire Risk Mitigation Memorandum Account ("FRMMA") from 1/1/2019 through 12/31/2019, and Fire Hazard Prevention Memorandum Account ("FHPMA") from 1/1/2010 through 12/31/2019. These accounts are hereinafter collectively referred to as the "Memorandum Accounts."

The purpose of the analysis we performed was to confirm that the costs included in the Company's cost recovery proceedings for the designated accounts, as captured in the Company's financial systems, reflected the costs directly attributable to the Memorandum Accounts and that any observations of possible deviations within the cost data provided (within the scope of our analysis) were not material to the overall costs incurred. PG&E plans to use this analysis to support its Wildfire Mitigation and Catastrophic Events ("WMCE") filing in a future proceeding.

Our analysis was conducted in accordance with the consulting professional standards in the Statement on Standards for Consulting Services ("SSCS") established by the American Institute of Certified Public Accountants. Furthermore, our approach is designed to achieve (to the extent possible given the limited scope of this work) the principles of the National Association of Regulatory Utility Commissions' ("NARUC") Rate Case and Audit Manual (2003) in an effective and efficient manner. We considered the guidance provided under Regulatory Assets and Other Deferrals section stating one "...should become familiar with the specific items in this account, including the nature of the entries, the dollar amounts, the reason for the deferrals, whether or not regulatory approval has been obtained (or is needed) for the deferrals." The guidance suggests further consideration regarding the nature of the deferrals and "whether the deferral is appropriate for inclusion in rate base. As noted in the manual, we relied on the commonly understood concepts of "prudence" and "reasonableness" when reviewing expenses and corresponding adjustments proposed by PG&E. The manual states the purpose of applying these concepts is to "determine a revenue requirement and customer rates that are just, fair, reasonable, and sufficient."

We also considered legislation in California Senate Bill (SB) 901, which mandates activities to strengthen California's ability to prevent and recover from catastrophic wildfires. This legislation contains additional requirements for utilities to address wildfire risks including implementing a comprehensive fire prevention plan. We embedded requirements from SB 901 and the Company's guidance on incremental costs related to the Memorandum Accounts within our testing steps and used this guidance to inform our conclusions.

Our procedures do not constitute an audit of the Company's financial statements nor do we provide any form of assurance on the financial statements as a whole. Our procedures did not constitute an audit, review or compilation as those terms are defined by the American Institute of Certified Public Accountants.

II. Executive summary

Objective

Based on information provided by PG&E relating to the costs included in the Company's cost recovery proceedings for the Memorandum Accounts, we prepared findings and observations regarding the inclusion of these costs in the Memorandum Accounts based on our testing and analysis. This report summarizes our approach to the analysis and testing of the Memorandum Accounts.

PG&E submitted a November 2018 Advice Letter to the Commission to open the FRMMA effective January 1, 2019. PG&E continues to use the FRMMA to record costs of wildfire mitigation activities not captured and approved in the annual WMPMA. For recordkeeping purposes, PG&E's business finance team treats all costs falling within either FRMMA or WMPMA as one and the same. The FHPMA contains costs not already being recovered in rates and predates the opening of the FRMMA by approximately a decade.

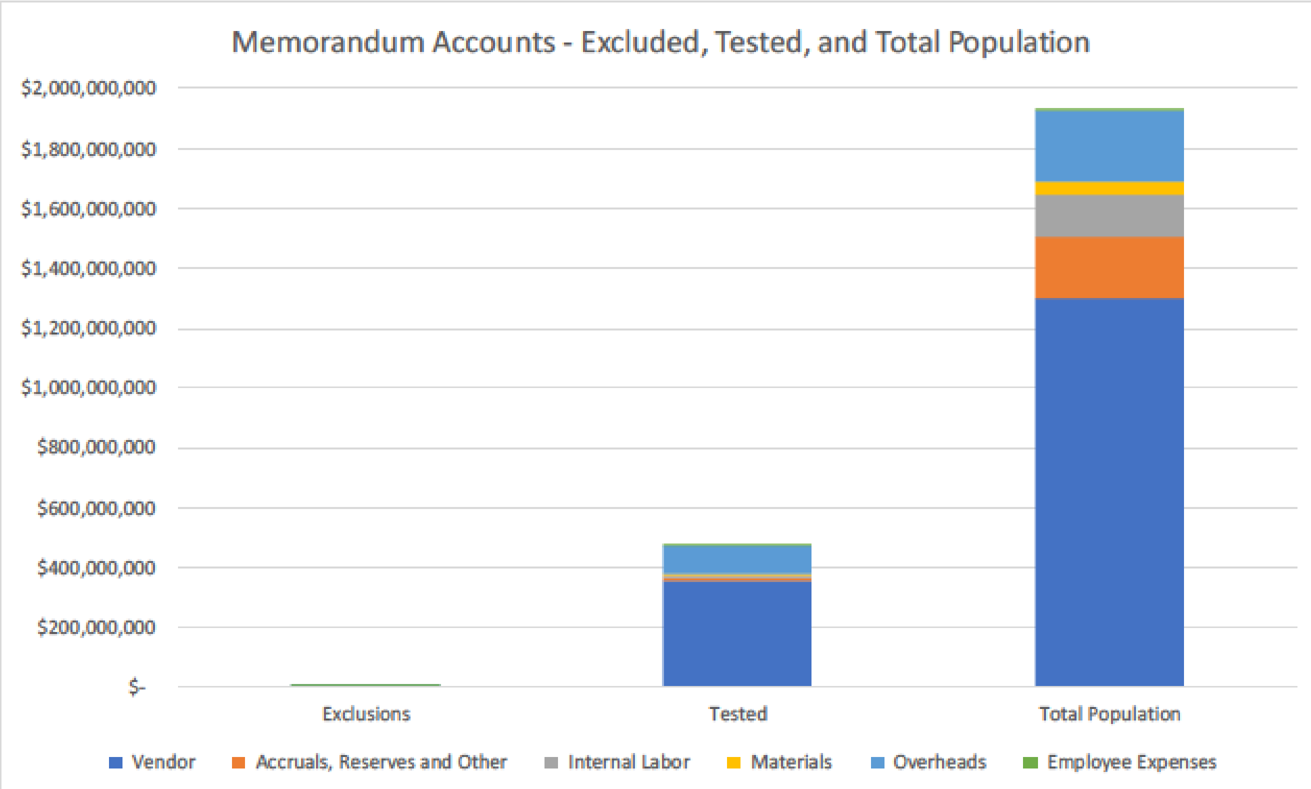
Our objectives were to:

1) Analyze whether the costs in the above referenced accounts totaling $1.9 billion were sufficiently supported, reasonable, and incremental in nature, and if the costs incurred were directly attributable to the Memorandum Accounts.
2) Develop observations relating to the costs for further consideration and provide those observations to the Company.
3) Request additional supporting documentation from the Company -- and confirm with the business owners and the Regulatory, Sourcing, and Finance Departments -- the facts surrounding the charges, and verify that there were no other pertinent facts that would impact the allocation of the charges to the Memorandum Accounts.
4) Prepare supporting workpaper documentation for all analyses, observations and conclusions.

The table below summarizes the cost categories:

Table 1 –Population of Memorandum Accounts by cost category

Cost Category	Amount	Transaction Amount Analyzed	% Tested
Vendor (Vendor Key, i.e. not null)	$ 1,301,879,235	$ 357,148,622	27%
Accruals, Reserves & Other	$ 203,754,152	$ 9,542,238	5%
Internal Labor (PGE1/660xxxx)	$ 140,303,017	$ 5,851,199	4%
Materials (PGE1/5300xxx)	$ 43,792,338	$ 2,452,902	6%
Overheads (PGE1/601xxxx)	$ 238,740,468	$ 96,293,030	40%
Employee Expenses (Vendor Key "U")	$ 5,849,899	$ 977,266	17%
Total	$ 1,934,319,109	$ 475,474,325	25%



Approach

Our approach consisted of first segregating the costs within the Memorandum Accounts by cost category and developing testing procedures for each category of costs based on the unique nature and risks of each cost category. We ran analytics across full populations to target these specific risks identifying transactions for testing detailed in the table below. We tested approximately 7,000 transactions totaling 25% of the total costs incurred. We collected approximately 14,000 documents containing supporting evidence for analysis. We also held multiple discussions across the organization including the Finance, Regulatory, and Sourcing Departments.

PG&E provided available data and supporting documentation for each of these cost categories. We developed and performed analytics and substantive testing tailored to each cost category, as further described within the "Procedures Performed" section of this report below.

In addition to the analysis and transaction testing, we also considered the incrementality of these costs, in totality, as compared to the last approved General Rate Case (GRC). We obtained the last GRC filing with supporting schedules to gain an understanding of the type and nature of costs included within current base rates. We then compared those costs and activities to the Memorandum Accounts to identify potential overlap or risk of double recovery. Furthermore, we considered the imputed 2019 GRC costs as compared to 2019 total actual incurred costs to identify large or unusual movements that may be indicative of GRC items being recorded in Memorandum Accounts.

Findings and Conclusions

As a result of the procedures described above, we identified no exclusions that would materially affect the balances of the Memorandum Accounts. Based on our analysis, we found no evidence to question management's conclusions that costs were: (i) incurred for the activities set forth in the corresponding, relevant CPUC approved Memorandum Accounts; (ii) accurately recorded; and (iii) incremental in nature.

As detailed below, we identified items totaling $2.9 million (extrapolated to $6.2 million) that were not properly evidenced for inclusion in the Memorandum Accounts largely due to:

1) Unsupported vendor expenses: We noted limited instances of vendors including expense amounts that were not properly evidenced within their invoice, the contract, or purchase order. These items contained: unsubstantiated per diems, inconsistent treatment of hotel charges, labor expense inconsistencies, and unsubstantiated other miscellaneous expenses.
2) Markups: We noted limited instances of vendors marking up subcontractor charges which were prohibited in the contract. Furthermore, we noted limited instances where vendors would be directly contracted by PG&E for a specific service and also engaged as a subcontractor (subject to markups by the prime) for a different service.
3) Transactions recorded in the wrong account: We noted limited instances were amounts were recorded within FRMMA that should have been recorded in FHPMA.
4) Nuclear generation charges: Labor and overheads charges for nuclear generation employees were identified in the population. In limited instances we were unable to confirm the employees role on the Memorandum Accounts.
5) Employee expenses: Employee expense charges were identified for certain employees who did not have accompanying labor charged to WMCE accounts. In limited instances we were unable to confirm the expenses were related to the Memorandum Accounts.

All excluded amounts for the aforementioned cost categories were validated and confirmed by PG&E for removal from the WMCE Cost Recovery Application. We understand PG&E intends to reflect proposed exclusions within the Memorandum Accounts and remove the proposed exclusions from the application.

III. Procedures performed

The following section will describe detailed procedures performed for each category of costs mentioned above.

Vendor Costs

Cost Category	Amount	Percent of Total Population
Vendor	$ 1,301,879,235	67%

Approach

We performed detailed transaction testing on $357 million of vendor costs or approximately 27% of total vendor costs from a starting population of approximately $1.3 billion. To arrive at a starting population of $1.3 billion for vendor costs, we first isolated accrual transactions totaling approximately $247 million from the full population of costs. We identified more than 70% of the accrual transactions as vendor costs and developed separate testing procedures for the vendor cost accrual amounts. The vendor cost accrual procedures are described below. For the remaining balance of invoiced vendor costs ($1.3 billion), we segregated the transactions into 3 categories for specific testing procedures: targeted selections, largest vendor and statistical sample.

We selected approximately $357 million for testing and tailored our testing approach based on the characteristic of the transaction as described in the three subcategories of vendor costs below.

Table 2 – Vendor cost subcategories

Ref	Vendor Costs - Subcategories	SAP Amount	Selected for Testing
A	Targeted	216,248,706	143,898,136
B	Largest Vendor (Quanta)	220,000,572	70,073,060
C	Statistical Sample	865,629,957	143,177,426
Total		$ 1,301,879,235	$ 357,148,622

A) Targeted: We identified a targeted selection of high dollar transactions over $100,000 from the $1.3 billion of vendor costs. We selected transactions based on available data within SAP, combined with available bulk invoice extracts and information extracted from a third party processing service (Taulia). We tested approximately $143 million of targeted selections from a population of approximately $216 million with available support. Our testing approach included analyzing invoices, contracts, purchase orders and other potentially relevant contemporaneous information.

B) Largest Vendor – Quanta Energy Services LLC ("Quanta"): We isolated the transactions for Quanta, a vendor with the largest total cost across the Memorandum Accounts. Quanta's total charges of $220 million were material to the overall vendor cost population of $1.3 billion. We selected approximately $70 million in transactions to perform detailed substantive testing following analysis of the full population of total Quanta costs. Our detail testing included analysis of underlying invoices, contracts, and purchase orders.

C) Statistical Sample: From the remaining untested vendor cost balance of approximately $866 million, we selected a statistical sample of transactions to compare financial data to supporting invoices and contracts.[1] Statistical sampling reports for both FRMMA and FHPMA are included as appendices to this report. Our testing approach included the same procedures applied to the

[1] The remaining untested vendor cost balance is the starting amount of $1.3 billion less the targeted population of approximately $216 million and less the largest vendor costs of approximately $220 million.

targeted selections, which included analyzing invoices, contracts, purchase orders and other potentially relevant contemporaneous information.

We performed the following steps in our testing of vendor costs

For our analysis of vendor costs, we developed a customized testing platform that functioned as a database and allowed for real-time reporting of testing metrics. To test vendor costs at a transactional level, we generated a unique ID for each transaction within our testing population and created a corresponding case file within the testing platform. Each case file contained relevant fields from SAP relating back to the transaction, a testing survey to document observations, and a file storage tab to append supporting documentation provided by PG&E.

The testing surveys were used to document our detailed transactional testing (described more below) and flag transactions meriting further analysis through the use of Reason Codes. The Reason Codes are as follows:

Table 3 – Reason Codes

Code	Exception description
R1	The transaction does not have a corresponding invoice.
R2	Company provided transaction data does not match supporting documentation. Amounts or work description per supporting documentation is inconsistent with transaction data.
R3	The transaction does not have supporting documentation/or is illegible/or has insufficient information.
R4	The transaction occurred outside of the Memorandum Account period.
R5	The transaction does not appear to be reasonably and prudently incurred. Flagged items may include unusually high unit costs, descriptions unrelated to WMPMA/FRMMA/FHPMA activities, etc.
R6	The transaction is not consistent with Company policy. Excluded items may include alcohol, tobacco, entertainment, etc.
R7	The transaction is potentially not incremental in nature.

Our detailed testing steps were as follows:

1) Reconciliation of SAP data to supporting documentation (R1, R2, R3, R4):
    a. We analyzed the underlying documentation to determine whether an invoice from a third party was provided.
    b. Upon receipt of an invoice, we compared the invoice amount, vendor name and other relevant identifiers to the relevant fields of SAP data to ensure vendor names were consistent and dollar amounts tied. 2
    c. If an invoice or the underlying support was lacking sufficient information or was illegible, we noted in the testing platform that additional documents or confirmations were needed to support the transaction amount.

[2] In certain, limited instances, an invoice could not be provided as the invoice was not retained or an electronic data interchange system was used in the place of traditional paper invoicing. In the event this occurred, a contract, purchase order, management records of approval, or other support was accepted in place of an invoice.

d. We analyzed the date or range of dates for services provided within the invoice and documented whether the services took place during the applicable scope periods for the Memorandum Accounts.

2) Reasonableness testing (R5, R6):

a. We performed analyses to determine if a transaction was reasonably and prudently incurred for the services provided by examining unit prices under each cost category (e.g. labor, equipment, materials, per diem, reimbursable expenses) and comparing those unit prices to prices charged by other vendors performing similar services. We requested additional documentation and confirmation for outliers noted during our testing and documented our findings within the testing survey.

b. We analyzed invoices, receipts, and other third party support to determine whether vendors billed for items that are prohibited by PG&E's employee expense policy such as alcohol, tobacco, or personal products and services.

3) Incremental nature of the transaction (R7):

a. We analyzed the information provided in the invoice, contract, and other support to determine whether the services performed appear to be incremental activity related to wildfire risk or prevention. We relied on Company policies and other guidance from PG&E described below to help identify the nature and timing of various incremental activities in addition to what was included in prior General Rate Case ("GRC") proceedings.

b. Per the Company's guidance on incremental costs, PG&E uses the FRMMA, WMPMA and FHPMA Memorandum Accounts to record costs related to wildfire mitigation activities. Legislation mandates additional requirements for utility operations, maintenance, and infrastructure improvements to address wildfire risk, including implementing a comprehensive fire prevention plan. Per PG&E's Regulatory Accounting Document (RAD # 19-06-03rev01 or "RAD"), PG&E tracks costs incurred for wildfire mitigation activities that are not otherwise covered in the utility's electrical corporation revenue requirements or the 2017 GRC. Within the RAD and Advice Letter 5419-E, planned mitigation activities defined as incremental costs fall under the following categories: 1) brand new programs, 2) substantial increase of costs exceeding what occurred during the last general rate case, or 3) inspections and repairs relating to high or very high fire threat, called "Tier II" or "Tier III," that exceeded what occurred during the last general rate case.

i. Brand new programs – These costs may include expense and capital expenditures relating to the following activities: investments in system hardening to reduce potential fire risks associated with overhead distribution systems (i.e. replacing bare overhead conductors with covered conductors, select undergrounding, and replacing equipment with low fire risk equipment certified by the California Department of Forestry and Fire Protection); expanded automation and protection programs including enhanced controls like Supervisory Control and Data Acquisition capability and implementing Public Safety Power Shutoffs ("PSPS") to proactively de-energize lines in high fire risk areas; and situational awareness programs for improving knowledge of local weather and environmental conditions.

ii. Substantial increase in costs over prior GRC – These costs relate to planned mitigation activities that were substantially increased over normal, routine costs recovered in the prior GRC. For example, vegetation management activities were increased as part of wildfire mitigation efforts on top of the routine activities included in the GRC, such as species removal, overhang clearing, fuel reduction, and other indirect costs associated with vegetation management (i.e. PMO, administration, IT, etc.).

iii. Inspections and repairs – These costs relate to inspections and repairs that were increased, enhanced or expanded over activities recovered in the prior GRC, including enhanced inspections of high fire threat areas, drone and helicopter inspections, climbing inspections of transmission towers, and repairs and capital replacements such as emergency maintenance, substation maintenance and pole maintenance. Also included in this category are costs incurred to identify issues and risks to public or employee safety which call for immediate corrective action.

For observations requiring further consideration, we grouped the vendor cost transactions for further investigation by Reason Codes. We later removed Reason Codes initially tagged to transactions meriting further review after we received additional documentation and confirmation demonstrating support for the charges within the transaction. In some instances, transactions were either partially or fully unsupported and were flagged using all relevant Reason Codes. In these instances, we calculated an excluded amount in dollars for all of the corresponding transaction that did not fully meet the testing requirements dictated by the Reason Codes.

We made the following observations in our testing of vendor costs

As a result of the procedures described above, we identified immaterial amounts that were lacking sufficient support or did not appear to be reasonably incurred totaling approximately $2.5 million in vendor costs.[3] We grouped the exclusions by type based on high level themes we identified within the testing we performed on our targeted and sampled selections. The themes are as follows:

1) Idled equipment - We identified limited instances of equipment time charged to the Company when no work was performed.
2) Labor - We identified limited instances related to overbillings, errors or missing support related to labor charges within the vendor invoices.
3) Lodging - We noted instances where hotel charges below the GSA rate were incurred by vendor employees while the GSA rate to PG&E was charged to the invoice (e.g. the vendor employee incurred actual charges of $150 per night but charged the GSA rate of $200 per night to the invoice). Additionally, we noted hotel charges incurred and charged to PG&E above the GSA rate (e.g. the vendor employee incurred actual charges of $250 per night and charged $250 per night to the invoice when the GSA rate was $200 per night).
4) Markup - We noted limited instances where a markup was incurred for passthrough charges on equipment, travel expense and other items aside from labor. We also noted limited instances where a subprime markup was incurred for labor where the subprime was also directly engaged by PG&E as a vendor.

[3] Approximately $2.5 million of identified exclusions does not include the extrapolated amount applied to the sampled vendor cost transactions.

5) Materials and supplies – We identified limited instances of alcohol, cigarettes and other miscellaneous personal charges (e.g, car wash) on the vendor invoice.
6) Per diem – We noted in some instances that the count of per diems incurred exceeded the count of vendor employees providing labor. In some instances, we noted supplemental per diems were incurred in excess of the original per diem per person or per diems were incurred when no labor was incurred.
7) Travel expenses – We identified limited instances where travel expense was lacking sufficient support or did not reconcile to the charges on the vendor invoice.
8) Vehicle – We noted in some instances that a monthly vehicle allowance was charged in conjunction with mileage charges. We identified limited instances where values greater than 10% of the GSA mileage rate were charged on the vendor invoice.

Table 4 – Vendor cost exclusions

Exclusion Type	Statistical Sample	Targeted Selections	Total
Idled Equipment	$ -	$ 17,487	$ 17,487
Labor	$ 34,025	$ 124,168	$ 158,194
Lodging	$ -	$ 153,106	$ 153,106
Markup	$ 284,859	$ 321,320	$ 606,179
Materials & supplies	$ 4,735	$ 118,344	$ 123,079
Per diem	$ 115,163	$ 456,655	$ 571,818
Travel expense	$ 2,213	$ 41,241	$ 43,454
Vehicle	$ 97,297	$ 762,250	$ 859,546
Total	$ 538,292	$ 1,994,570	$ 2,532,862

All excluded amounts were validated and confirmed by PG&E for removal from the WMCE Cost Recovery Application.[4] We understand PG&E intends to reflect proposed vendor cost exclusions within the Memorandum Accounts and remove the proposed exclusions from the application.

We also identified limited instances where costs were recorded to FRMMA related to services performed before the scope period began on January 1, 2019. PG&E validated approximately $1.5 million of vendor costs for reclassification into FHPMA. We understand PG&E also intends to reflect this reclassification within the application.

During our transactional testing for vendor costs, we obtained documentation and questioned Company personnel to understand other available recovery mechanisms for wildfire and catastrophic event type activities such as the Catastrophic Event Memorandum Account ("CEMA"). This enabled us to evaluate the WMCE transactions with a view to the differing characteristics of various recovery mechanisms and to identify potentially misclassified transactions within the Memorandum Accounts subject to transaction testing. While performing our transaction testing described above, we flagged transactions that we identified as potentially recoverable in other accounts. We followed up with the Company to obtain further information evidencing inclusion in the Memorandum Accounts. Substantially all flagged items were related to PSPS events or fuel reduction activities. We understand these events have overlapping activities related to both Memorandum Account activities and CEMA

[4] Refer to Section IV – Summary of findings and recommendations for further detail regarding the excluded amount for vendor costs.

activities. We worked with the Company to obtain an understanding of these differences and determined the applicable recovery mechanism was to include the transactions we identified within the Memorandum Accounts.

We performed additional testing of the largest vendor

We identified Quanta as PG&E's largest vendor related to the costs incurred in the Memorandum Accounts. Quanta performs contracting services including the design and installation of infrastructure projects and invoices PG&E through both its parent and various subsidiary companies. We performed a holistic analysis of Quanta's total charges of approximately $220 million as they were material to the overall vendor cost population.

Our holistic analysis across the population of Quanta transactions helped us to identify approximately $70 million in transactions for testing. To conduct our holistic analysis, we analyzed the services described in multiple Quanta contracts and compared these contracted services to the descriptions in SAP for the Order, Purchase Order and other identifying fields. The purpose of this comparison was to determine if any services within SAP appeared to fall outside of the scope of contracted services. We also selected additional transactions for testing by the Order number when we identified an excluded amount in a Quanta transaction. If a transaction within our selections resulted in a partial or full exclusion, we identified the Order number in the full population of Quanta transactions and sampled additional transactions containing the same Order number. As a result of this process, we tested a total of $70 million in Quanta transactions.

We also selected additional transactions to test with the largest dollar amount by transaction for two reasons. First, we considered the materiality of the transaction compared to the full population of Quanta transactions and noted multiple transactions greater than $5 million. We also compared the full population of Quanta transactions to a listing of Planning Orders provided by PG&E for costs that the Company planned to no longer seek recovery. We noted multiple high dollar transactions greater than $5 million where recovery would not be sought and tested a selection of these high dollar transactions to analyze them for identifiable trends that may also be present within the population of Quanta transactions where PG&E plans to seek recovery. We wanted to verify whether the same or similar identifiable trends were found within transactions where PG&E would seek recovery and not seek recovery to determine if further exclusions were merited. Upon performing our analysis on comparing nonrecoverable to recoverable transactions, no anomalies were identified.

After we identified and selected additional Quanta transactions for testing based on our holistic analysis, we performed the same transactional testing procedures in our testing platform as described in our testing of vendor costs above. The table below summarizes the additional dollars tested for Quanta as compared to the total population of costs.

Table 5 – Additional Quanta testing by dollar and Memorandum Account

Quanta Energy Services, LLC	Total	FRMMA	FHPMA
Total population	$ 220,000,572	$ 219,815,567	$ 185,005
EY tested population	$ 70,073,059	$ 69,888,054	$ 185,005
% Tested population	31.9%	31.8%	100%

As we previously stated, we understand that all excluded amounts were validated and confirmed by PG&E for removal from the WMCE Cost Recovery Application. No pervasive or thematic exclusions were noted as it pertains to Quanta outside of the exclusion types noted above.

We performed additional testing of vendor costs classified as capital expenses

For transactions recorded as a capital expense, we performed additional testing procedures to understand whether a transaction appeared to be related to a capital project and therefore was accurately coded. Capital expenses are eligible for recovery, similar to the other vendor costs. However, a utility treats capital expenses differently as it relates to the utility's revenue requirement or the amount of recovery a utility is allowed to collect from its ratepayers. Operating expenses are typically recovered at cost whereas capital expenditures are typically recovered using a cost plus basis, meaning these types of costs are multiplied by an allowed rate of return. For this reason, additional procedures were performed to analyze the classification of a cost as a capital expenditure as opposed to an operating expense. In the scope of our testing for vendor costs, we tailored our testing procedures to address these issues and applied additional scrutiny to capital expenses.

We received a listing of expense types by the Major Work Category ("MWC"), which is a field within SAP. We compared the listing we received to the vendor cost transactions within SAP to identify which costs were classified as a capital expense by the Company. We also identified the total cost by expense type within the vendor cost transactions we tested, which is summarized in the table below.

Table 6 – Vendor costs classified as capital expenses selected for testing

Expense Type	Amount	Selected for Testing
Capital	$ 319,362,236	$ 84,936,749
Operations and Maintenance	$ 982,516,999	$ 272,211,872
Total Vendor Costs	$ 1,301,879,235	$ 357,148,621

We consulted the Company's capitalization policy and retirement unit guidelines to consider whether there was sufficient evidence for the capitalization of a transaction cost. Additionally, we referenced the Retirement Unit Catalog ("RUC") to determine whether the transactions tagged as a capital expense contained assets that appeared to be recorded in the RUC. In instances where further information was required to determine the proper classification, we also compared the plant asset on the invoice to the Order description in SAP, which provided additional insight into the nature of each expense.

At the transactional level, we performed capital expense testing using the third party invoice we received and any additional supporting documents such as the contract or purchase order to validate that capitalization of the transaction adhered to the Company's internal guidance. In some instances, we identified transactions containing costs which were not clearly defined in the capitalization policy of the retirements catalog. We also identified an amount of costs related to vegetation management services, which through discussion with management we understand can be capitalized as a component cost of a major capital project. We selected these transactions for testing and performed the additional testing procedures outlined below:

1) We analyzed the makeup of the orders where vegetation management was recorded to understand whether this was a component cost of a major capital project.
2) Where the percentage of the vegetation management costs made up a major portion of vendor costs within the overall order, we requested PG&E to provide the status of the order. If the order was still open and incurring costs, this would indicate that the vegetation management occurred at the beginning of the project resulting in a high percentage at the time of testing. In all instances selected, PG&E confirmed that the orders were still open and active.
3) For the remaining transactions not clearly identified as related to vegetation management we requested additional documentation supporting confirmation of the services provided, projects serviced, and how that project relates to the activity within the Memorandum Accounts. Based on the additional support we received, it appeared that the transaction costs were for the purchase of long-term capital assets supporting the activity within the Memorandum Accounts.

We made the following observations in our testing of capital expenses

Overall, capitalized costs appeared to be accurately recorded and costs were incurred for capital assets or in support of a capital program. For these reasons, we did not identify any exclusions from the total population of capitalized costs.

Accruals, Reserves and Other

Cost Category	Amount	Percent of Total Population
Accruals	$ 203,754,152	11%

Approach

We identified a total population of approximately $204 million of accruals, reserves and other costs. Within this population, we noted approximately $247 million of accruals within FRMMA and a credit balance (i.e. a negative cost amount) of approximately $44 million related to reserves and other costs within the Memorandum Accounts. We did not perform holistic or transactional testing on the populations of reserves or other costs.

We tested approximately $9.5 million of accrual transactions that were recorded in SAP as of December 31, 2019 related to vendor costs. We analyzed the population of vendor cost accruals holistically and noted 12 transactions related to Enhanced Vegetation Management ("EVM") totaling approximately $81 million. We noted that approximately 80% of the EVM accruals were comprised of two transactions, and we performed an EVM accrual walkthrough with the Business Finance department to better understand the nature and timing of these accruals before selecting additional transactions to test.

Business Finance confirmed that the EVM accruals were manual entries made in SAP on or before December 31, 2019 to accrue for EVM services provided before year-end. We learned that Business Finance developed its estimate from multiple sources of information before recording the manual entries. Business Finance stated it gathered data from its electronic data interchange ("EDI") system that vendors providing EVM services can use to invoice the Company. Business Finance noted the invoicing data driving its accrual calculation for the manual entries was data considered "in progress" within the system (i.e., not yet submitted as a finalized and billed amount). Business Finance stated various PG&E personnel also spoke directly to vendors who did not use PG&E's EDI system to obtain an estimate of costs incurred, but not yet billed through year-end.

Business Finance stated the 2019 manual EVM accrual entries totaling approximately $81 million were supported with finalized vendor invoices received in 2020 for approximately $100 million, which means the Company under accrued for EVM services by approximately $20 million. Business Finance confirmed they will seek recovery for the $20 million difference in next year's proceedings, and that amount will not be reflected in the period under review.

Business Finance provided us with a workbook of transactional level detail corresponding to the 12 manual accrual entries in order to select samples for testing. Using the workbook and the SAP data, we selected samples at the transactional level from the workbook and the full population of accruals within the corresponding SAP data for the Memorandum Accounts.

We performed the following steps in our testing of accruals

For our targeted selections of accruals making up $9.5 million, we collected available invoices and performed testing related to the timing of the accrual entry and the reasonableness of the accrual estimate. We compared the SAP data to the third party invoice and other related support to perform the following testing procedures:

1) Reasonableness of estimate:
    a. We performed a reasonableness test on the estimate of services to be performed in the respective Memorandum Account period by comparing the accrual amount to the invoiced amount.[5] A transaction was determined to be supported if the accrued amount was less than or equal to the actual invoiced amount. In limited instances, an accrued amount was greater than the actual invoiced amount. The implication of an over accrual

[5] The full population of accrual transactions tested was within FRMMA. The scope period for FRMMA is from January 1, 2019 through December 31, 2019, meaning the focus of our analysis was year-end 2019.

is that rate payers could be potentially paying for services that were performed in a future period beyond the scope period. However, Business Finances confirmed an under accrual of approximately $20 million for EVM accruals, meaning immaterial discrepancies would likely not result in a net over accrual across the population.

2) Cut-off testing:
   a. We conducted cut-off testing to determine if the timing of the accrual entry was reasonable compared to the date or range of dates the services were performed on the invoice compared to the date the transaction was recorded in SAP. A transaction was determined to be supported if the work was performed prior to the accrual date, an invoice was received and recorded subsequent to the accrual date, and the accrual amount was ultimately reversed out.

We made the following observations in our testing of accruals

We identified immaterial differences at the transactional level where accruals were recorded for all or a portion of the invoiced services in the prior period and subsequent period (i.e., 2018 & 2020). In aggregate, accrual transactions appeared to be recorded in the proper period and supported by invoices for services rendered in 2019. As previously noted, the Company recorded manual accruals totaling approximately $81 million, which was later determined to be under accrued by $20 million. The under accrual amount is material and indicative of a net under accrual across the population of transactions we tested. The Company also noted the under accrual will not be reflected in the FRMMA Memorandum Account for the period under review. For these reasons, we did not identify any exclusions from the total population of vendor cost accruals.

Internal Labor

Cost Category	Amount	Percent of Total Population
Internal Labor	$ 140,303,017	7%

Approach

The total internal labor amount identified in the FHPMA and FRMMA data exports was $140.3 million.

We performed analytics on the $140.3[6] million of internal labor costs by reviewing labor hours, rates, job titles, cost centers, and other related fields in SAP and identified outliers based on the distribution of labor data and industry knowledge.

We identified the following outlier categories and made targeted selections for additional testing totaling $5.8M:

A) Employee workdays with 16 or more labor hours charged by an employee on a single day: We identified transactions where an employee charged 16 or more labor hours on a single day. We performed a targeted selection of these transactions and requested timesheets and work descriptions for the work performed.

B) Employee workdays with an employee labor rate greater than or equal to $175 per hour: We reviewed the population of labor data and identified outliers in labor rates. This threshold was based on the distribution of labor charges to the Memorandum Accounts as well as our experience with market rates across the industry. Line items with labor rates greater than or equal to $175 per hour were selected for further testing.

C) Employees with job titles/cost centers referencing "Nuclear" or "Generation": We identified labor costs with cost centers referencing "Nuclear" or "Generation." These cost centers are not normally associated with activities relating to wildfire risk or prevention; therefore we selected these transactions to perform additional testing.

D) Non-Standard Labor Costs: We identified non-standard labor charges without an employee key, quantity of hours, and associated rate. We performed a targeted selection of these charges and requested invoices and/or other supporting documentation to help map these costs back to the financial records.

We performed the following steps in our testing of internal labor

We requested supporting documentation for our targeted selection of outliers and performed the following additional procedures:

A) Workdays with 16 or More Labor Hours:

We performed a walkthrough with PG&E and followed SAP detail through to supporting timesheets and work descriptions provided by PG&E. In each instance, the time sheets supported the amount of hours charged and the work was related to a Public Safety Power Shutoff (PSPS) event. Per discussion with PG&E Supervisor of Electric Business Finance, PSPS events are treated as emergencies similar to storms, fires and floods.

[6] This amount is based on PG&E employees internal labor charges. Consulting and contractor costs may not show up within this total and would be reviewed through vendor cost invoices.

As a result, overtime is expected, and crews work around the clock to restore power and mitigate PSPS hazards.

B) Workdays with Labor Rates Greater Than or Equal to $175 Per Hour:

We analyzed other related fields within SAP to distinguish the types of labor where labor rates were greater than or equal to $175/hour. The outliers selected for further tested related to the following Cost Elements: 1) IT Analyze, Plan, Mtce, etc. Tier 4; 2) IT Analyze, Plan, Mtce, etc. Tier 5; 3) IT Software Development tier 4; 4) Management Services and 5) Contractor Admin.

Per communications with PG&E, PG&E utilizes activity-based costing. IT contractor costs utilize a tiered billing process that is based on the billed costs from vendors. Activity types are grouped into tiers and are assigned standard rates that closely align to the rates billed by vendors. For example, if the vendor is invoicing PG&E for $125/hour for a resource, that resource will use tier 3 activity type and will bill at $125/hour.

Based on the information provided by PG&E, we compared the assigned rates to the tiered standard rates and determined the IT cost elements were within the ranges provided.

C) Internal Labor Related to Wildfires by Nuclear & Generation Employees:

PG&E provided a data file mapping Employee Key to Job Position[7]. We utilized this data file to reconcile the Employee Keys on the FRMMA labor population data to Job Titles. We performed analytics on the long-form Job Titles provided by PG&E and/or their associated cost element to quantify the labor costs related to non-electrical employees (Nuclear & Generation) in the FRMMA population. EY identified 30 employees with job titles related to Nuclear or Generation with internal labor costs allocated to FRMMA.

PG&E provided a list of Generation EEs that worked on the Wildfire Safety Inspection Program (WSIP). Per supporting documentation, 24 Nuclear or Generation employees that allocated internal labor costs to FRMMA were confirmed to have worked on WSIP.

D) Non Standard – Labor Costs:

identified non-standard labor charges without an employee key, quantity of hours, and associated rate and requested invoices and other supporting documentation.

Through discussion with PG&E, it was determined that the charges were related to use of Blackhawk helicopters purchased in 2018 for wildfire mitigation purpose.

The helicopter costs are related to "chargebacks." Per PG&E, the Aviation Services cost center processes the invoices from their cost center and "charges back" the cost to the appropriate order through an internal allocation process using the sender cost center. We received invoice support for limited selections. Invoices evidenced the costs incurred for pilot time, fuel, and other operational usage charges from outside service providers.

[7] Copy of Internal Labor - Employee Listing.xlsx

We made the following observations in our testing of internal labor

1) Labor rates greater than or equal to $175 per hour $7,366: Transactions with labor rates greater than or equal to $175 per hour relating to the Management Services and Contractor Admin Cost Elements were identified without supporting detail. We recommend excluding these costs from the WMCE filing.
2) Internal Labor related to Wildfires by Nuclear & Generation Employees $13,955: Transactions for 6 Nuclear and/or Generation employees were identified without evidence supporting these employees to have internal labor allocated to FRMMA. We recommend excluding these costs from the WMCE filing.

Materials

Cost Category	Amount	Percent of Total Population
Materials	$ 43,792,338	2%

Approach

The total material amount identified in the FHPMA and FRMMA data exports was $43.8 million.

We performed walkthroughs of the process to distribute and account for materials. We then ran analytics on the $43 million of material costs by performing key word searches and unit cost analysis, and high dollar transactions.

We identified the following outlier categories and made targeted selections for additional testing totaling $2.4M:

A) <u>Non-Electric Material types:</u>

We performed key word searches across the materials population for Gas/Water/Transmission type materials and identified materials with the cost element "Gas & Water Specialties." From that population, we identified a targeted selection of these transactions and requested work orders and project descriptions for which these materials were used.

B) <u>Higher than average unit cost</u>

We performed a unit price statistical analysis based on material descriptions and cost elements for capital and expense related materials. Based on these results, we selected materials with high standard deviations compared to their respective averages (coefficient of variation) for further testing. We requested documentation supporting the cost of the high/low material price and appropriate entry into the system.

C) <u>High dollar transactions</u>

We identified high dollar transactions within the materials population made targeted selections on this population. We requested shipment location of the materials to verify that the amount and quantity of materials represented in the system were shipped to a location within the fire grid.

We performed the following steps in our testing of materials

A) <u>Non-Electric Material Types:</u>

Through inquiries with management and analyzing the supplemental evidence we identified that in each instance of materials with the cost element "Gas & Water Specialties." the material was for galvanized pipe required for an electric pole replacement project and appropriately allocated to the memorandum accounts.

B) <u>Unit Cost by Material Type:</u>

Through discussions with supply chain, it was determined that the "long text" material description associated with the material key was not provided in the original data set. The long text description distinguishes variations among material type groupings. We were provided the "long text description" for each material we selected it appears reasonable that there would be variation in price based on the underlying detail provided. Overall, unit prices for materials were consistent across material descriptions with a total variation percentage of 3.26%. Outliers identified during the unit price analysis make up less than 1% of the total sample population of $43.8 million.

C) <u>Shipment Location of Materials:</u>

Through discussions with supply chain it was determined that the Plant Maintenance orders have a Maintenance Work Center representing the location of shipment of the materials. For all instances where there was a shipment location, we compared the location provided to the 2019 CAL FIRE map and determined that the shipment location of the materials was within the fire grid. In limited instances, the selections were associated with a controlling order which does not have a maintenance work center defining the location of shipment. In these instances we were provided controlling order description and based on that, it appeared that the material usage was related to memorandum account activity.

We made the following observations in our testing of materials

- We did not identify any exclusions from the total population of materials.

Overheads

Cost Category	Amount	Percent of Total Population
Overheads	$ 238,740,468	12%

Approach

The total overhead amount identified in the FHPMA and FRMMA data exports was $238.7 million.

We performed analytics on the $238.7 million by analyzing amounts included in the cost pools, allocation percentages applied, and the type of overheads included in the Memorandum Accounts.

We performed the following analytical procedures and selected overhead categories for recalculation totaling $93 million;

A) <u>Holistic analysis of overhead charges</u>

We reviewed the full overhead population to identify anomalies or abnormalities in types of overhead charged (electric vs non-electric), base for application, allocation percentage, and fluctuation in allocation percentage over the calendar year.

We Identified 27 cost elements in the overhead data provided by PG&E totaling $238.7 million. We then reviewed actual 2019 overhead allocation rates including monthly allocation rates and base amounts for each overhead category. We used the information provided to recalculate the 2019 anticipated allocations for each of the 27 cost elements. We identified variances between the recalculated amounts and the allocation amounts booked to each account.

Following our recalculation, we had several discussions with PG&E stakeholders to better understand the overhead allocation approach. During these discussions, we learned the following:

- Overhead allocations are applied using a tiered approach.
- PG&E uses templates to input data points for recalculation purposes.

As a result of this analysis, we selected a targeted sample of overhead categories from the population and requested PG&E to provide recalculation based on rates for respective periods and base cost categories.

B) <u>Analysis of Non-Electric overheads</u>

Within the overhead categories, we identified two non-electric cost elements: 6010109 (Indirect Labor – Nuclear Gen) and 6010117 (Operation Mgmt & Support – Nuclear Gen). We selected these for recalculation and requested additional data linking back to the labor base for allocation.

We performed the following steps in our testing of overhead charges

A) Holistic analysis of overhead charges:

Based on discussions with PG&E, we selected specific order numbers to review within each of the nine cost elements. PG&E provided detailed calculations for these nine specific orders for the selected months.

- We reviewed actual 2019 overhead allocation rates and selected months with the highest fluctuations in rates.
- The order numbers selected in the table above represent the order numbers with the highest allocation amounts for the months selected.

We reviewed calculations provided by PG&E and identified no variances.

Table 7: Selections for recalculation

Cost Element	Cost Element Description	OH Amount	Order Selection	2019 Month Selection
6010106	Indirect Labor - Electric	29,639,582	8189917	September
6010120	Benefits OH	24,126,733	70037405	March
6010100	Paid Time Off	20,121,460	74021961	July
6010123	Fleet OH	11,010,607	35120949	December
6010121	Payroll Taxes OH	8,600,237	74021961	May
6010107	Indirect Labor - Gas	1,876,006	31410440	January
6010115	Operation Mgmt & Support - Gas	842,145	35109832	November
6010109	Indirect Labor - Nuclear Gen	63,060	31466938	December
6010117	Operation Mgmt & Support - Nuclear Gen	13,201	7093505	October

B) Analysis of Non-Electric overheads:

We reviewed calculations provided by PG&E and identified no variances. However, although the recalculation was mathematically accurate, we were unable to trace the Nuclear Generation base amount to which the allocation percentage was applied back to the internal labor data. Without identification of the base population, we were unable to confirm the employee's role as it relates to WMCE events.

We made the following observations in our testing of overhead costs

1) For nuclear generation overheads, the labor base for allocation for was not identified. As such we were unable to confirm the non-electric employees' role in the WMCE events. Without supporting evidence for the entire labor population for which the allocation percentage was applied to, we recommend excluding these costs from the WMCE filing.

Employee Expense

Cost Category	Amount	Percent of Total Population
Employee Expenses	$ 5,849,899	0.3%

Approach

The total employee expense amount identified in the FHPMA and FRMMA data exports was $5.8 million.

We performed a combination of transaction testing through statistical sampling, and data analytics over the $5.8 million of employee expenses.

For transaction testing we selected a statistical sample of transactions to compare financial data to supporting invoices and contracts. Statistical sampling reports for both FRMMA and FHPMA are included as appendices to this report. Our testing approach included the same procedures applied to the targeted selections in the vendor cost selection above, which included analyzing invoices, contracts, purchase orders and other potentially relevant contemporaneous information.

Through the data analytics, we identified the following outlier category and made targeted selections for additional testing totaling $977K:

A) Employees charging expenses with no accompanying labor charge
We compared employee expenses charged to the internal labor data provided by PG&E for both FRMMA ($130.4 million) and FHPMA ($9.9 million). Employees who charged expenses to WMCE orders but did not have accompanying labor hours charged were identified in the Employee Expense population. In order to determine the validity of the submission of these expenses, we selected the top ten employees in both FRMMA and FHPMA with the highest amount of expenses and no associated labor charges. We requested supporting documentation evidencing the relationship of the charges to the Memorandum Accounts including employee job description, job assignment and business purpose for charges.

We performed the following steps in our testing of employee expenses

A) Employees charging expenses with no accompanying labor charge

Per discussions with PG&E management, we understand that among the population identified above, there were administrative employees who were responsible for booking and making purchases on behalf of employees who were in the field responding to PSPS events. There were also "Type B" employees who are not allowed to "chargeout" labor to the specific cost centers they may be supporting. Based on our understanding of conversations with PG&E stakeholders, PG&E employees are assigned a base cost center (Type A or Type B). Employees tagged to the Type B cost centers do not charge their labor to WMCE orders, but are still authorized to charge expenses.

PG&E provided testimony from 15 of the 20 employees confirming their role, what the expense charges were for, and how they related to WMCE events.

We made the following observations in our testing of employee expenses

1) Employees charging expenses with no accompanying labor charge $233,909: Employee expenses amongst five different employees are related to Type A employees. These employees would be expected to have labor hours accompanying expenses charged to WMCE orders and evidence supporting this amount was not provided. We recommend excluding these costs from the WMCE filing.

Incrementality

Cost Category	Amount	Percent of Total Population
Total population	$ 1,934,319,109	100%

Approach

In addition to the analyses and transaction testing described above, we considered the incrementality of the Memorandum Accounts in totality as compared to the last approved GRC. Testing on an individual transaction level does not allow for broader understanding of the account level activity. We performed an analysis starting from the full population of transactions at both the Memorandum Account and general ledger account level. The purpose of analyzing the Memorandum Accounts holistically as compared to the last GRC filing was to identify potential overlap or risk of double recovery.

PG&E plans to seek recovery for approximately $1.5 billion in costs related to FRMMA compared to approximately $28 million in costs related to FHPMA for the calendar year 2019. It is important to note we did not consider earlier proceedings related to the costs recorded in FHPMA dating back to 2010. We did not consider imputed or actual costing data for other years outside of 2019, as a substantial amount of costs within the scope of our engagement occurred in 2019. As noted below, we found no evidence that indicated we should expand our analysis beyond 2019.

We performed the following steps in our testing of incrementality

We reviewed documents and filings related to the prior proceedings, discussed Company practices and previous experience with PG&E personnel, and evaluated our ability to identify account level costing that was incremental, incurred for, and directly attributable to the Memorandum Accounts. We obtained the last GRC filing with supporting schedules to gain an understanding of the type and nature of costs included within current base rates. We also obtained PG&E's 2019 Risk Spending Accountability Report ("RSAR") and analyzed it to understand actual expense compared to imputed costs. The purpose of the RSAR is to provide a summary of actual expense compared to imputed values derived from the Company's 2017 GRC decision. We considered the imputed 2019 GRC costs as compared to 2019 total actual incurred costs to identify large or unusual movements that may be indicative of GRC items being recorded in Memorandum Accounts.

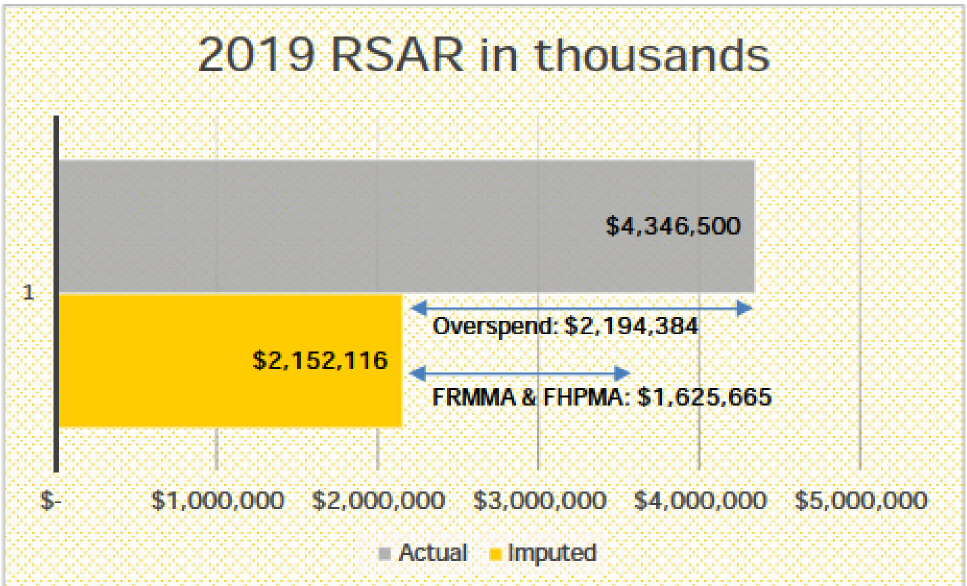
We performed additional procedures to analyze the incrementality of the Memorandum Accounts in totality as compared to the last GRC and on an activity level basis. Our procedures are as follows:

1) We obtained PG&E's 2017 GRC and the applicable supporting schedules, and we analyzed the account level activities to understand the nature and timing of the activities contained within approved rates. The purpose of this analysis was to understand account level activities included within the last GRC compared to new, evolving or the same types of account activity we noted within the SAP data we received for the Memorandum Accounts.
2) We obtained PG&E's 2019 RSAR and analyzed it to understand the 2019 imputed amounts compared to PG&E's 2019 actual spend at the account level. The activities and amounts in the RSAR appear to be in line with our understanding of the account level activities documented within the company's 2017 GRC. Additionally, we noted that the comparison of imputed to actual 2019 spend demonstrates PG&E overspent their GRC by approximately $2.2 billion which is captured in Table X below.
3) We received the company's 2019 Electric Line of Business file ("LOB") file, which includes substantially all activity in 2019 related to the company's electric operations. We compared the account level activities in FRMMA that were captured in the Electric LOB file to our transactional FRMMA data from SAP to analyze our starting population in SAP for accuracy and completeness. No material differences were noted over the course of our analysis.
4) We met with the Business Finance department to better understand the Company's Electric LOB file and received a walkthrough to reconcile the Memorandum Accounts to the Company's 10-K disclosure. This step was performed to further our understanding around the accuracy and completeness of the population of costs in totality as they were recorded to the financial statements.

We made the following observations in our holistic analyses of incrementality

Based on our holistic analyses, the company appears to have overspent its 2019 imputed balance by approximately $2.2 billion. We noted within the RSAR data that of the approximately $2.2 billion in overspend, $1.6 billion is attributed to the Memorandum Accounts[8]. Additionally, the Company appears to have overspent its GRC above and beyond the amount of the Memorandum Accounts by a total of approximately $600 million.

Table 8 – 2019 RSAR with actual costs of approximately $4.3 billion



We compared the Electric LOB file to the 2019 RSAR at the account activity level to understand whether specific account level activity costs actually incurred reconciled to the difference between the imputed and actual amounts incurred within the 2019 RSAR. We noted limited instances where account level activity amounts recorded to FRMMA were greater than the 2019 RSAR overspend, suggesting there may be overlapping recovery. We identified three Major Work Categories where the Company's overspend in the 2019 RSAR was less than the totals recorded to FRMMA in the 2019 Electric LOB data. The aggregate difference was approximately $91 million across these three account level activities.

[8] We compared the overspend to the total spend within the SAP data we received for 2019 FRMMA and 2019 FHPMA costs, which was approximately $1.6 billion and $28 million respectively.

Table 9 – 2019 RSAR account level activity cost differences compared to 2019 LOB costs

MWC	MWC Description	2019 RSAR Difference (Overspend)	FRMMA LOB Costs	Recording difference
08	Electric Distribution Reliability Base - Overhead Asset Replacement	$ 253,850	$ 281,060	$ (27,210)
49	Electric Distribution Circuit/Zone Reliability Program	$ 3,860	$ 57,185	$ (53,325)
BF	Electric Operations Patrols/Inspections	$ 155,338	$ 165,421	$ (10,083)
Total				$ (90,618)

PG&E confirmed the reason this occurred was due to differences at the Maintenance Activity Type ("MAT") activity level, which is a coding that distinguishes a more granular account level activity than the MWC coding. We analyzed the MAT coding for MWCs 08, 49, and BF and noted significant overspend at the MAT code level related to FRMMA activities. We identified three MAT level activities that appeared to reflect activities we noted on vendor invoices during our vendor cost testing. It is worth noting the 2019 RSAR imputed spend for both System Hardening and PSPS activities was zero, which is indicative of incremental spend.

Table 10 – 2019 RSAR account level activity by MAT code related to FRMMA overspend

MWC	MWC Description	MAT	MAT Description	2019 RSAR Actual	2019 RSAR Imputed	Difference
08	Electric Distribution Reliability Base - Overhead Asset Replacement	08W	System Hardening: Wildfire Resiliency projects	$ 287,429	$ -	$ 287,429
49	Electric Distribution Circuit/Zone Reliability Program	49H	Public Safety Power Shutoff (PSPS) Sectionalizer Device Install/Replace	$ 51,193	$ -	$ 51,193
BF	Electric Operations Patrols/Inspections	BFB	Overhead Poles Inspected	$ 138,261	$ 10,986	$ 127,275
Total						$ 465,898

We found no material differences related to the account level activity imputed and incurred in the 2019 RSAR compared to the 2019 Electric LOB file upon receiving the aforementioned confirmations from PG&E. After completing our procedures described above, we did not note any specific discrepancies between 2019 imputed versus incurred costs or material differences in spend within the account level of activity recorded in PG&E's filings compared to their internal records. It does not appear that the GRC overspend in 2019 is indicative of costs being moved to the Memorandum Accounts for recovery already sought within a prior proceeding (i.e. double recovery).

IV. Summary of findings and recommendations

Conclusions

As a result of the procedures described above, we identified no exclusions that would materially affect the balances of the Memorandum Accounts. Based on our analysis, we found no evidence to question management's conclusions that costs were: (i) incurred for the activities set forth in the corresponding, relevant CPUC approved Memorandum Accounts; (ii) accurately recorded; and (iii) incremental in nature.

As a result of the procedures described above, we did identify items totaling $2.9 million (extrapolated to $6.2 million) that were not properly evidenced for inclusion in the Memorandum Accounts.

Table 10 - Observations for potential exclusion

Cost Category	Exclusion Type	Statistical Sample	Targeted Selections	Total
Vendor	Idled Equipment	$ -	$ 17,487	$ 17,487
Vendor	Labor	$ 34,025	$ 124,168	$ 158,194
Vendor	Lodging	$ -	$ 153,106	$ 153,106
Vendor	Markup	$ 284,859	$ 321,320	$ 606,179
Vendor	Materials & supplies	$ 4,735	$ 118,344	$ 123,079
Vendor	Per diem	$ 115,163	$ 456,655	$ 571,818
Vendor	Travel expense	$ 2,213	$ 41,241	$ 43,454
Vendor	Vehicle	$ 97,297	$ 762,250	$ 859,546
Internal Labor	Rate > $200 per hour	$ -	$ 7,366	$ 7,366
Internal Labor	Nuc/Gen	$ -	$ 13,955	$ 13,955
Overhead	Nuc/Gen	$ -	$ 76,260	$ 76,260
Employee Expenses	Type A Employee	$ -	$ 233,910	$ 233,910
Total		$ 538,292	$ 2,326,062	$ 2,864,354
Total - Extrapolated		$ 3,862,334	$ 2,326,062	$ 6,188,396

We propose the following items, grouped by high level themes identified within our testing, to be excluded from the Memorandum Accounts:

1) Vendor Costs: We noted limited instances of vendors including expense amounts that were not properly evidenced within their invoice, the contract, or purchase order. These items contained: unsubstantiated per diems, inconsistent treatment of hotel charges, labor expense inconsistencies, and unsubstantiated other miscellaneous expenses. We noted limited instances of vendors marking up subcontractor charges prohibited in the contract. Furthermore, we noted limited instances where vendors would be directly contracted by PG&E for a specific service and be treated as a subcontractor (subject to markups by the prime) for a different service.
2) Internal Labor: We noted limited instances where internal labor charges contained labor rates greater than or equal to $175 per hour related to the Management Services and Contractor

Admin Cost Elements. We were not able to identify supporting detail for the excessive rates. We also noted limited instances of internal labor charges related to Nuclear and/or Generation employees. We were unable to identify evidence supporting the internal labor the employees allocated to FRMMA.

3) Overhead: The labor base for allocation for Nuclear Generation overheads for approximately $76,000 was not identified. We were unable to confirm the non-electric employees' role as it related to the WMCE events.
4) Employee Expense: We identified employee expenses of approximately $234,000 related to Type A employees. These employees would be expected to have labor hours accompanying expenses charged to Orders within the Memorandum Accounts and evidence supporting this amount was not provided.

All excluded amounts for the aforementioned cost categories were validated and confirmed by PG&E for removal from the WMCE Cost Recovery Application. We understand PG&E intends to reflect proposed exclusions within the Memorandum Accounts and remove the proposed exclusions from the application.

V. Appendix A – Statistical sampling methodology

Pacific Gas and Electric Company
2020
Fire risk mitigation memorandum account
Sampling and estimation report

Ernst & Young LLP
1101 New York Avenue, NW
Washington, DC 20005

September 21, 2020

Contents

Introduction

The purpose of the Pacific Gas and Electric Company (PG&E) 2020 fire risk mitigation memorandum account (FRMMA) study was to estimate the total error amount for the transactions incurred in 2019 by certain vendors in FRMMA. This report focuses exclusively on the statistical sampling and estimation component of the study. Decisions about the review process and the sample determinations are not part of this report.

Questions regarding the sampling and estimation methodology can be directed to Siyu Qing at (202) 327-7210 or Ryan Petska at (202) 327-7245.

Section I: Executive summary

A stratified sample of 270 transactions was selected from a sampling population of 112,126 transactions in PG&E FRMMA. Based on the results of the sample, it was estimated that the total error amount was $2,042,284 with margins of error of $897,617 and $1,075,639 at 90 and 95 percent confidence level respectively.

Table 1 summarizes the estimation results.

Table 1. Estimation summary

Estimation Category	Estimated Amount	Margin of Error at 90% Confidence Level	Margin of Error at 95% Confidence Level
Total Error Amount	$ 2,042,284	$ 897,617	$ 1,075,639

Section II: Population

Population

The original population contained 128,922 transactions totaling $616,371,373 in transaction cost (cost). After removing debit/credit matches based on the fields Planning Order - Key, Order - Key, Purchasing Doc - Key, Vendor - Key, PO Item - Key, EY CO Doc First and the absolute value of the cost, the final population consisted of 125,700 transactions totaling $616,371,373 in cost. The final population also contained -$73,308,081 in negative transactions (credits) which were set aside during sample design and adjusted for during estimation via a credit adjustment. Thus, the resulting sampling population contained 112,126 transactions totaling $689,679,454 in cost.

A summary of the population is provided in Table 2.

Table 2. Population summary

	Total Net		Positives (Debits)		Negatives (Credits)	
	Total Cost	Number of Records	Total Cost	Number of Records	Total Cost	Number of Records
Original Data	**$ 616,371,373**	**128,922**	**$ 719,010,170**	**113,737**	**$ (102,638,797)**	**15,185**
- Debit/Credit Match	$ -	3,222	$ 29,330,716	1,611	$ (29,330,716)	1,611
Final Population	**$ 616,371,373**	**125,700**	**$ 689,679,454**	**112,126**	**$ (73,308,081)**	**13,574**
Sampling Population	**$ 689,679,454**	**112,126**	**$ 689,679,454**	**112,126**	**$ -**	**-**

Sampling unit

The sampling unit was an individual transaction.

Sampling frame

The sampling frame consisted of 112,126 transactions totaling $689,679,454 in cost.

Section III: Sample design

Stratification

A stratified random sample design was used for the study. Stratified sample designs are highly efficient designs that often allow confidence and precision goals to be obtained with smaller samples than would be required with simple random samples. The population data was divided into groups, or strata, and each stratum was sampled separately, with different sampling rates to increase the efficiency of the design. During estimation, the sampled records were appropriately weighted to reflect the sampling rates for the different strata. In this study, the individual transaction's cost amount was used as the basis for stratification.

A certainty or take-all stratum was defined for transactions with large costs relative to the rest of the data (greater than or equal to $1,200,000). Transactions in this stratum were sampled at a rate of 100 percent in an effort to improve the stability of the estimate.

The sample design is shown below in Table 3.

Table 3. Sample design summary

Stratum Number	Stratum Definition	Population Size	Population Cost	Sample Size	Sample Cost
1	$0 to $499.99	53,265	$ 7,812,613	30	$ 4,629
2	$500 to $6,209.99	45,338	$ 76,849,785	30	$ 52,733
3	$6,210 to $20,299.99	8,187	$ 90,686,966	30	$ 324,731
4	$20,300 to $52,009.99	2,832	$ 92,365,063	30	$ 957,464
5	$52,010 to $99,899.99	1,316	$ 93,832,065	30	$ 2,216,465
6	$99,900 to $198,999.99	685	$ 93,710,121	30	$ 3,860,198
7	$199,000 to $414,999.99	329	$ 93,409,711	30	$ 8,557,398
8	$415,000 to $1,199,999.99	144	$ 91,085,236	30	$ 19,227,702
9	$1,200,000 and above	30	$ 49,927,894	30	$ 49,927,894
Total		**112,126**	**$ 689,679,454**	**270**	**$ 85,129,215**

Section IV: Sample selections and results

Source and seed of random numbers

The function RANUNI in the statistical software, SAS, was used to generate the random numbers for sample selection. The seed used to generate the random numbers was 616371373; it represented the total cost in the full population prior to removing any out-of-scope transactions.

Serialization of frame

Prior to generating random numbers in SAS, the population was sorted by the field EY PK. The purpose of this sort was to place the file in a reproducible and verifiable order so the random number assignment was independent of an arbitrary frame sequence.

Method of selection

To select the sample, the sampling frame was sorted by stratum and the random numbers described above. Thus, the entire file was put into random order within a stratum. Then, the required number of transactions per stratum was selected according to this random order. For example, the first 30 transactions in this random order were selected for stratum one.

Sample results

The results of the sample review are available upon request. Table 4 provides a summary of the results by stratum.

Table 4. Sample results summary

Stratum Number	Stratum Definition	Population Size	Population Cost	Sample Size	Sample Cost	Sample Error Amount
1	$0 to $499.99	53,265	$ 7,812,613	30	$ 4,629	$ -
2	$500 to $6,209.99	45,338	$ 76,849,785	30	$ 52,733	$ -
3	$6,210 to $20,299.99	8,187	$ 90,686,966	30	$ 324,731	$ 96
4	$20,300 to $52,009.99	2,832	$ 92,365,063	30	$ 957,464	$ 211
5	$52,010 to $99,899.99	1,316	$ 93,832,065	30	$ 2,216,465	$ 30,719
6	$99,900 to $198,999.99	685	$ 93,710,121	30	$ 3,860,198	$ 18,873
7	$199,000 to $414,999.99	329	$ 93,409,711	30	$ 8,557,398	$ 24,880
8	$415,000 to $1,199,999.99	144	$ 91,085,236	30	$ 19,227,702	$ 3,519
9	$1,200,000 and above	30	$ 49,927,894	30	$ 49,927,894	$ 170,767
Total		**112,126**	**$ 689,679,454**	**270**	**$ 85,129,215**	**$ 249,066**

Section V: Estimation

Standard statistical methods were used to produce the estimates from the stratified sample. Differences in the probabilities of selection among strata were properly accounted for by statistical weighting. The mean per unit (MPU) estimator[9] was used to compute the estimated total error amount.

The MPU estimator

The MPU estimator is the weighted sum of the sample means of error amount over all strata. In stratified sampling with L strata, this can be represented as

$$\hat{\cdot}_{mpu} = \sum N_h \bar{y}_h,$$

where

N_h is the number of transactions in stratum h,
$\bar{y}_h$ is the sample mean of error amount, and
h = 1 to L, the number of strata.

The standard error of the MPU estimate is given by

$$\hat{S}(\hat{Y}_{mpu}) = \sqrt{\sum N_h (N_h - n_h) S_{yh}^2 / n_h},$$

where

[9] Roberts, D. M. (1978) Statistical Auditing, American Institute of Certified Public Accounts, Inc., New York.

$S_{yh}^2 = \sum \frac{(y_{hi} - \bar{y}_h)^2}{n_h - 1}$ is the sample variance of error amount in stratum h.

Confidence limits were calculated from the estimate plus or minus its margin of error, where the margin of error is computed as the standard error times the Student's t-value with a 90 or 95 percent two-sided confidence.

The degrees of freedom for the t-value were approximated using the Satterthwaite formula as follows:

$$n_e = \left(\sum g_h s_{yh}^2\right)^2 \Big/ \sum \frac{g_h^2 s_{yh}^4}{n_h - 1},$$

where

$$g_h = N_h(N_h - n_h)/n_h.$$

As a result of the Satterthwaite adjustment, the t-value used in estimation was 1.674 and 2.006 for 90 and 95 percent confidence level respectively.

Table 5 shows the estimated total error amount and its associated precision measures.

Table 5. Estimation results summary

			90% Two-sided Confidence Level			95% Two-sided Confidence Level		
Estimation Category	Estimated Amount	Standard Error	Margin of Error	Lower Bound	Upper Bound	Margin of Error	Lower Bound	Upper Bound
Total Error Amount	$ 2,042,284	$ 536,211	$ 897,617	$ 1,144,667	$ 2,939,902	$ 1,075,639	$ 966,645	$ 3,117,924

Credit adjustments

The estimated total error amount was adjusted to account for the -$73,308,081 remaining credits. The overall estimated total error amount, determined from the sample (positive amounts only), was adjusted by applying the estimated error percentage of 0.3 percent to the unmatched credits (-$73,308,081). Therefore, the adjusted estimated total error amount was calculated as follows:

$2,285,183 + (0.3% * (-$73,308,081)) = $2,042,284.

Pacific Gas and Electric Company

2020

Fire hazard prevention memorandum account

Sampling and estimation report

Ernst & Young LLP
1101 New York Avenue, NW
Washington, DC 20005

September 21, 2020

Contents

Introduction

The purpose of the Pacific Gas and Electric Company (PG&E) 2020 fire hazard prevention memorandum account (FHPMA) study was to estimate the total error amount for the transactions incurred from 2010 to 2019 by certain vendors in FHPMA. This report focuses exclusively on the statistical sampling and estimation component of the study. Decisions about the review process and the sample determinations are not part of this report.

Questions regarding the sampling and estimation methodology can be directed to Siyu Qing at (202) 327-7210 or Ryan Petska at (202) 327-7245.

Section I: Executive summary

A stratified sample of 167 transactions was selected from a sampling population of 13,506 transactions in PG&E FHPMA. Based on the results of the sample, it was estimated that the total error amount was $1,820,050 with margins of error of $1,396,098 and $1,679,113 at 90 and 95 percent confidence level respectively.

Table 1 summarizes the estimation results.

Table 1. Estimation summary

Estimation Category	Estimated Amount	Margin of Error at 90% Confidence Level	Margin of Error at 95% Confidence Level
Total Error Amount	$ 1,820,050	$ 1,396,098	$ 1,679,113

Section II: Population

Population

The original population contained 16,811 transactions totaling $249,258,585 in transaction cost (cost). After removing debit/credit matches based on the fields Planning Order - Key, Order - Key, Purchasing Doc - Key, Vendor - Key, PO Item - Key, EY CO Doc First and the absolute value of the cost, the final population consisted of 14,823 transactions totaling $249,258,585 in cost. The final population also contained -$26,378,696 in negative transactions (credits) which were set aside during sample design and adjusted for during estimation via a credit adjustment. Thus, the resulting sampling population contained 13,506 transactions totaling $275,637,281 in cost.

A summary of the population is provided in Table 2.

Table 2. Population summary

	Total Net		Positives (Debits)		Negatives (Credits)	
	Total Cost	Number of Records	Total Cost	Number of Records	Total Cost	Number of Records
Original Data	**$ 249,258,585**	**16,811**	**$ 363,789,501**	**14,500**	**$ (114,530,916)**	**2,311**
- Debit/Credit Match	$ -	1,988	$ 88,152,220	994	$ (88,152,220)	994
Final Population	**$ 249,258,585**	**14,823**	**$ 275,637,281**	**13,506**	**$ (26,378,696)**	**1,317**
Sampling Population	**$ 275,637,281**	**13,506**	**$ 275,637,281**	**13,506**	**$ -**	**-**

Sampling unit

The sampling unit was an individual transaction.

Sampling frame

The sampling frame consisted of 13,506 transactions totaling $275,637,281 in cost.

Section III: Sample design

Stratification

A stratified random sample design was used for the study. Stratified sample designs are highly efficient designs that often allow confidence and precision goals to be obtained with smaller samples than would be required with simple random samples. The population data was divided into groups, or strata, and each stratum was sampled separately, with different sampling rates to increase the efficiency of the design. During estimation, the sampled records were appropriately weighted to reflect the sampling rates for the different strata. In this study, the individual transaction's cost amount was used as the basis for stratification.

A certainty or take-all stratum was defined for transactions with large costs relative to the rest of the data (greater than or equal to $1,200,000). Transactions in this stratum were sampled at a rate of 100 percent in an effort to improve the stability of the estimate.

The sample design is shown below in Table 3.

Table 3. Sample design summary

Stratum Number	Stratum Definition	Population Size	Population Cost	Sample Size	Sample Cost
1	$0 to $199.99	6,607	$ 291,660	30	$ 1,471
2	$200 to $43,699.99	5,596	$ 43,695,011	30	$ 236,355
3	$43,700 to $142,999.99	863	$ 66,607,087	30	$ 2,311,809
4	$143,000 to $371,999.99	319	$ 68,051,759	30	$ 6,166,616
5	$372,000 to $1,199,999.99	104	$ 66,860,363	30	$ 19,200,560
6	$1,200,000 and above	17	$ 30,131,402	17	$ 30,131,402
Total		**13,506**	**$ 275,637,281**	**167**	**$ 58,048,212**

Section IV: Sample selections and results

Source and seed of random numbers

The function RANUNI in the statistical software, SAS, was used to generate the random numbers for sample selection. The seed used to generate the random numbers was 2492586; it represented the total cost in the full population, prior to removing any out-of-scope transactions, divided by 100 and rounded to the nearest integer.

Serialization of frame

Prior to generating random numbers in SAS, the population was sorted by the field EY PK. The purpose of this sort was to place the file in a reproducible and verifiable order so the random number assignment was independent of an arbitrary frame sequence.

Method of selection

To select the sample, the sampling frame was sorted by stratum and the random numbers described above. Thus, the entire file was put into random order within a stratum. Then, the required number of transactions per stratum was selected according to this random order. For example, the first 30 transactions in this random order were selected for stratum one.

Sample results

The results of the sample review are available upon request. Table 4 provides a summary of the results by stratum.

Table 4. Sample results summary

Stratum Number	Stratum Definition	Population Size	Population Cost	Sample Size	Sample Cost	Sample Error Amount
1	$0 to $199.99	6,607	$ 291,660	30	$ 1,471	$ 43
2	$200 to $43,699.99	5,596	$ 43,695,011	30	$ 236,355	$ 693
3	$43,700 to $142,999.99	863	$ 66,607,087	30	$ 2,311,809	$ 33,330
4	$143,000 to $371,999.99	319	$ 68,051,759	30	$ 6,166,616	$ 24,867
5	$372,000 to $1,199,999.99	104	$ 66,860,363	30	$ 19,200,560	$ 170,402
6	$1,200,000 and above	17	$ 30,131,402	17	$ 30,131,402	$ 59,891
Total		**13,506**	**$ 275,637,281**	**167**	**$ 58,048,212**	**$ 289,227**

Section V: Estimation

Standard statistical methods were used to produce the estimates from the stratified sample. Differences in the probabilities of selection among strata were properly accounted for by statistical weighting. The mean per unit (MPU) estimator[10] was used to compute the estimated total error amount.

The MPU estimator

The MPU estimator is the weighted sum of the sample means of error amount over all strata. In stratified sampling with L strata, this can be represented as

$$\hat{Y}_{mpu} = \sum N_h \bar{y}_h,$$

where

N_h is the number of transactions in stratum h,
$\bar{y}_h$ is the sample mean of error amount, and
h = 1 to L, the number of strata.

The standard error of the MPU estimate is given by

$$\hat{S}(\hat{Y}_{mpu}) = \sqrt{\sum N_h (N_h - n_h) S_{yh}^2 / n_h},$$

where

$S_{yh}^2 = \sum \frac{(y_{hi} - \bar{y}_h)^2}{n_h - 1}$ is the sample variance of error amount in stratum h.

[10] Roberts, D. M. (1978) Statistical Auditing, American Institute of Certified Public Accountants, Inc., New York.

Confidence limits were calculated from the estimate plus or minus its margin of error, where the margin of error is computed as the standard error times the Student's t-value with a 90 or 95 percent two-sided confidence.

The degrees of freedom for the t-value were approximated using the Satterthwaite formula as follows:

$$n_e = \left(\sum g_h s_{yh}^2\right)^2 \Big/ \sum \frac{g_h^2 s_{yh}^4}{n_h - 1},$$

where

$$g_h = N_h(N_h - n_h)/n_h.$$

As a result of the Satterthwaite adjustment, the t-value used in estimation was 1.692 and 2.035 for 90 and 95 percent confidence level respectively.

Table 5 shows the estimated total error amount and its associated precision measures.

Table 5. Estimation results summary

			90% Two-sided Confidence Level			95% Two-sided Confidence Level		
Estimation Category	Estimated Amount	Standard Error	Margin of Error	Lower Bound	Upper Bound	Margin of Error	Lower Bound	Upper Bound
Total Error Amount	$ 1,820,050	$ 825,117	$ 1,396,098	$ 423,952	$ 3,216,148	$ 1,679,113	$ 140,936	$ 3,499,163

Credit adjustments

The estimated total error amount was adjusted to account for the -$26,378,696 remaining credits. The overall estimated total error amount, determined from the sample (positive amounts only), was adjusted by applying the estimated error percentage of 0.7 percent to the unmatched credits (-$26,378,696). Therefore, the adjusted estimated total error amount was calculated as follows:

$2,012,663 + (0.7% * (-$26,378,696)) = $1,820,050.

VI. Appendix B – Company documentation received

PG&E policy and guidance documents considered

We considered policies and procedures associated with the charging and/or allocation of charges related to WMPMA, FRMMA, FHPMA, CEMA and OII Settlement, as well as Company guidance and relevant documents related to 2019 Wildfire Mitigation Plan, CPUC-approved Preliminary Statement, Fire Safety Rulemaking decisions, Resolution E-3238, Public Utilities Code Section 454.9, Payment approval level or authorization, and Employee expense reimbursements.

Document Title	Description
1. Wildfire OII Final DD 20200507.pdf	Wildfire OII Settlement
2. ELEC_5419-E.pdf	Advice Letter 5419-E for FRMMA
3. ELEC_5555-E.pdf	Advice Letter 555-E for WMPMA
4. RegulatoryAccountingDocuments_Admin-Doc_PGE_20190910_578256.pdf	WMPMA/FRMMA RAD
5. 2019 Plan	Amended 2019 Wildfire Mitigation Plan, dated February 6, 2019
6. 2020 Plan	2020 Wildfire Mitigation Plan per PG&E's website
7. Fire Safety OIR Decision.pdf	Fire Safety Rulemaking Decision
8. Decision-Archive_Final-Dec_CPUC_19910724_Res-E-3238_204404.pdf	Resolution E-3238
9. Public Utilities Code Section 454.9	Public Utilities Code Section 454.9
10. FIN-2210P-01_FIN-2210P-01+Arranging+Travel+and+Reimbursing+Business+Expenses.pdf	Arranging Travel and Reimbursing Business Expenses Procedure
11. FIN-2210S_FIN-2210S+Employee+Business+Expense+and+Travel+Standard.pdf	Employee Business Expenses and Travel Standard
12. GOV-7+_Contract+Approval+and+Signing+Policy.pdf	Contract Approval and Signing Policy
13. GOV-3001S+_GOV-3001S+Contract+Signing+Authority+Standard.pdf	Contract Signing Authority Standard
14. GOV-3002P-01_GOV-3002P-01+Significant+Transaction+Review+Procedure.pdf	Significant Transaction Review Procedure

15.	GOV-3002P-01+Att.+1_Att.+1+Significant+Transaction+Worksheet.pdf	Significant Transaction Worksheet
16.	GOV-3002P-01+Att.+2_Att.+2+Potential+Form+8-K+Disclosure.pdf	Significant Transaction Review Procedure
17.	GOV-3002P-01+Att.+3_Att.+3+Significant+Transaction+Review+Credit+Questionnaire.pdf	Significant Transaction Review Credit Questionnaire
18.	GOV-3002P-01+Att.+4_Att.+4+STR+Routing+Instructions.pdf	Instructions for Routing a Significant Transaction Using EDRS
19.	GOV-3002S_GOV-3002S+Significant+Transaction+Review+Standard.pdf	Significant Transaction Review Standard
20.	Approvals+for+Expenditures+of+Funds+and+Disposals+of+Property,+and+Contract+Signing+Policy.pdf	Approvals for Expenditures of Funds and Disposals of Property, and Contract Signing Policy
21.	RISK-3004S_RISK-3004S+Sourcing+Credit+Risk+Management.pdf	Sourcing Credit Risk Management Standard
22.	GRC-2017-Phl_Report_PGE_20200330_600096.pdf	2019 Risk Spending Accountability Report in compliance with CPUC Decision 19-04-020
23.	GRC-2017-Phl_Test_PGE_20150901_346388.pdf	2017 General Exhibit Exhibit (PG&E-4) Electric Distribution Workpapers Supporting Chapters 1A and 2 - 12
24.	Phl_Test_PGE_20150901_346389.pdf	2017 General Exhibit Exhibit (PG&E-4) Electric Distribution Workpapers Supporting Chapters 13 - 19
25.	Electric LOB Total Costs.xlsx	2019 Electric Line of Business costs
26.	https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB901	California Senate Bill (SB) 901

PACIFIC GAS AND ELECTRIC COMPANY

2020 WILDFIRE MITIGATION AND CATASTROPHIC EVENTS

CHAPTER 9

ACCOUNTING ADJUSTMENTS

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CHAPTER 9
ACCOUNTING ADJUSTMENTS

A. Introduction

This chapter presents adjustments to Pacific Gas and Electric Company's (PG&E) Electric Distribution, Gas Transmission and Distribution, Power Generation, Shared Services, Corporate Services, Information Technology, and Customer Care recorded costs sought through this application in the following accounts:

1. Fire Risk Mitigation Memorandum Account (FRMMA);
2. Wildfire Mitigation Plan Memorandum Account (WMPMA);
3. Fire Hazard Prevention Memorandum Account (FHPMA);
4. Catastrophic Event Memorandum Account (CEMA);
5. Land Conservation Plan Implementation Account (LCPIA); and
6. Residential Rate Reform Memorandum Account (RRRMA).

This chapter describes the removal of costs—relating to the Wildfire Order Instituting Investigation Decision (Wildfire OII Decision), overhead cost variance, and Assembly Bill (AB) 1054—in section B below that have been already reflected in Chapters 2 through 7.

This chapter also describes additional adjustments made in this Chapter 9 to reflect reductions for:

- Ernst & Young's recommendations;
- Insurance proceeds; and
- CEMA overhead and administrative and general (A&G) adjustments.

This latter group of adjustments are shown in tables 9-1 and 9-2 below and described more fully in section C. The adjusted costs described in this chapter are used to calculate the corresponding revenue requirement shown in Chapter 10.

Table 9-1 below shows, by chapter, the total costs presented in the accompanying testimony (Chapters 2 through 7), as well as the adjustments made to these recorded costs. Subsequently, Table 9-2 shows the total costs by memorandum account. After adjustments, as shown in the tables below, the costs for which PG&E seeks recovery are $1.2 billion in expenses and $0.8 billion in capital expenditures.

TABLE 9-1
TOTAL COSTS AND ADJUSTMENTS BY CHAPTER
(THOUSANDS OF DOLLARS)

Line No.	Chapter	Memo Accounts	Expense	Capital Expenditures	Total
1	Chapter 2: ED – Wildfire Mitigations	FHPMA, FRMMA/WMPMA	$1,008,987	$574,326	$1,583,313
2	*Remove:*				
3		*Ernst & Young recommendations*	*(5,860)*	*(328)*	*(6,188)*
4		Subtotal	$1,003,127	$573,998	$1,577,125
5	Chapter 3: ED – CEMA	CEMA	$182,204	$196,007	$378,210
6	*Remove:*				
7		*Overheads and A&G*	(15,141)	(9,366)	(24,507)
8		*Insurance proceeds*	(6,669)	–	(6,669)
9		Subtotal	$160,394	$186,641	$347,035
10	Chapter 4: Gas	CEMA	$35,470	$20,552	$56,022
11	*Remove:*				
12		*Overheads and A&G*	*(3,798)*	*(705)*	*(4,503)*
13		*Insurance proceeds*	*(18,331)*	–	*(18,331)*
14		Subtotal	$13,341	$19,847	$33,188
15	Chapter 5: Power Generation	WMPMA, CEMA, LCPIA	$2,986	$3,215	$6,201
16	*Remove:*				
17		*Overheads and A&G*	–	*(107)*	*(107)*
18		Subtotal	2,986	$3,108	$6,094
19	Chapter 6: IT	WMPMA	$5,900	$17,643	$23,543
20	Chapter 7: Customer Care	RRRMA	$(3,738)	–	$(3,738)
21	Total Recorded Adjusted		$1,182,010	$801,236	$1,983,246

TABLE 9-2
TOTAL COSTS AND ADJUSTMENTS BY ACCOUNT
(THOUSANDS OF DOLLARS)

Line No.	Account	Expense	Capital Expenditures	Total
1	CEMA	$218,371	$219,773	$438,144
2	Adjustments:			
3	*Overheads and A&G*	*(18,939)*	*(10,177)*	*(29,117)*
4	*Insurance proceeds*	*(25,000)*	–	*(25,000)*
5	CEMA recorded adjusted	$174,431	$209,596	$384,027
6	FRMMA/WMPMA	$722,063	$591,969	$1,314,031
7	Adjustments:			
8	*Ernst & Young recommendations*	*(2,379)*	*(328)*	*(2,708)*
9	FRMMA/WMPMA recorded adjusted	$719,683	$591,640	$1,311,324
10	FHPMA	$295,037	–	$295,037
11	Adjustments:			
12	*Ernst & Young recommendations*	*(3,481)*	–	*(3,481)*
13	FHPMA recorded adjusted	$291,557	–	$291,557
14	LCPIA	77	–	77
15	RRRMA	$(3,738)	–	$(3,738)
16	Total Recorded Adjusted	$1,182,010	$801,236	$1,983,246

B. Costs Already Excluded from Chapters 2-7

The following amounts were already excluded from the costs presented in Chapters 2-7 of the testimony.

1. Wildfire OII Decision

On June 27, 2019, the California Public Utilities Code (CPUC or Commission) issued the Wildfire OII Decision 19-06-015 to determine whether PG&E "violated any provision(s) of the California Public Utilities Code (PU Code), Commission General Orders or decisions, or other applicable rules or requirements pertaining to the maintenance and operation of its electric facilities that were involved in igniting fires in its service territory in 2017." On December 5, 2019, the Assigned Commissioner amended the scope of issues to be considered in that proceeding to include the 2018 Camp Fire.

On December 17, 2019, PG&E, the Safety and Enforcement Division (SED) of the CPUC, the CPUC's Office of the Safety Advocate (OSA), and the Coalition of California Utility Employees (CUE) jointly submitted to the CPUC a proposed settlement agreement in connection with that proceeding. Pursuant to the settlement agreement, PG&E agreed that it would not seek rate recovery of certain wildfire-related expenses and expenditures in future applications, which totaled $1.625 billion. In addition, PG&E agreed to spend $50 million, funded by shareholders, on 20 specified System Enhancement Initiatives. On May 7, 2020, the CPUC issued a final decision that included modifications to the settlement agreement.[1] This Decision imposed penalties totaling $2.137 billion, which included $1.823 billion in disallowances for wildfire-related expenditures.[2]

In accordance with these disallowances, PG&E has not included the amounts described below in the costs presented in Chapter 2. Specifically, the following costs were excluded from this application.

- FRMMA/WMPMA exclusion: The Wildfire OII Decision disallowed 2019 distribution safety inspections and distribution safety repair costs tracked in the FRMMA/WMPMA. As of December 31, 2019, PG&E had incurred $165.4 million related to electric distribution safety inspections and $43.4 million in expense for electric distribution safety repairs.[3] PG&E has removed these amounts from recorded expense in this application.
- FHPMA exclusion: The Wildfire OII Decision disallowed $36 million of costs related to electric distribution Accelerated Wildfire Risk Reduction (AWRR) base camp and administrative expense tracked in the FHPMA. PG&E has excluded $34.7 million of AWRR recorded expense amount in this application.

2. Overhead Cost Variance

Overhead costs are applied to orders based on internal and contract activity. As these overheads are analyzed following the monthly settlement of costs, an overhead cost variance adjustment is processed when a particular program is over-burdened with overhead costs. Due to the magnitude of the wildfire mitigation work in relation to other work, an adjustment was booked for year-end 2019 to properly allocate overhead

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1 D.20-05-019.

2 D.20-05-019, pp. 2 and 36.

3 The Wildfire OII Decision estimated the 2019 distribution safety inspections costs to be $157 million and 2019 distribution safety repair costs to be $79 million.

costs across electric programs. Specifically, a $33.1 million reduction in FRMMA/WMPMA was applied during year-end of 2019 that was related to an overhead cost variance. This amount was excluded from the costs presented in Chapter 2.

3. AB1054 AFUDC Adjustment

In compliance with the AB1054 statutory requirement that prohibits large electrical corporations from including in equity rate base their share of the $5 billion spent statewide on fire risk mitigation capital expenditures, PG&E has made two types of adjustments. The first, which was already addressed in the capital costs in Chapters 2 and 6, is that PG&E has removed from the FRMMA/WMPMA the cost of equity of $574 thousand booked to Allowance for Funds During Construction (AFUDC). The second, which appears in Chapter 10, is that PG&E has removed $18.7 million associated with the return on rate base.

Please refer to Chapter 10, Section 2c, for more details on the AB1054 equity return removal on wildfire related capital costs.

C. Adjustments

PG&E has removed the following amounts from the costs presented elsewhere in this application.

1. Reductions Due to Ernst & Young Recommendations

As described in Chapter 8 and its attachment, Ernst & Young identified items totaling approximately $2.9 million (extrapolated to approximately $6.2 million) that Ernst & Young recommended for removal from this application. The amounts requested in this application have been reduced by this amount as shown in Tables 9-1 and 9-2 above.

2. Insurance Proceeds

Pursuant to Public Utilities Code Section 454.9 and Resolution E-3238, PG&E is allowed to seek recovery for direct expenses and capital costs related to catastrophic events. Resolution E-3238 also states that:

> While costs incurred for repairs may well be significant, they may not necessarily all be properly recoverable from ratepayers. Recovery may be limited by consideration of the extent to which losses are covered by

insurance,… and possibly other factors relevant to the particular utility and event.[4]

Consistent with the Resolution, PG&E has removed $25 million from this application to reflect insurance recovery proceeds related to the 2017 Tubbs Fire.

As a result of the 2017 Tubbs Fire, PG&E sustained damage to transmission and distribution lines, buried gas mains, underground gas service connections, service centers, utility poles, meters, transformers, and related equipment. As of September 30, 2020, the $25 million insurance proceeds represents the total amount of the collection in relation to costs represented in this application.

PG&E continues to provide supporting documentation and cooperate with requests for proof of loss to the insurance companies. PG&E expects to receive future insurance recoveries; however, the timing and amounts are uncertain. As insurance proceeds are received, PG&E will return these amounts to ratepayers. We will provide an update on any further proceeds in our rebuttal testimony.

3. CEMA Overhead and A&G Costs

In accordance with Decision 08-01-021, PG&E is removing all capitalized A&G costs charged to the capital orders in its CEMA. Furthermore, PG&E is excluding employee benefit costs associated with labor expense incurred for the CEMA Events. PG&E has removed $18.9 million related to employee benefit costs and $10.2 million in capitalized A&G overheads expense.

D. Conclusion

As shown in this chapter, PG&E has removed from its cost recovery request appropriate adjustments relating to the Wildfire OII Decision, overhead cost variance, AB 1054, recommendations from our external auditor Ernst & Young, insurance proceeds, and CEMA overhead and A&G costs.

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[4] Res.E-3238, pp. 2-3.

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CHAPTER 10

REVENUE REQUIREMENT

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CHAPTER 10
REVENUE REQUIREMENT

A. Introduction

The purpose of this chapter is to present the revenue requirement associated with the incremental costs recorded in the Fire Hazard Prevention Memorandum Account (FHPMA), the Fire Risk Mitigation Memorandum Account (FRMMA), the Wildfire Mitigation Plan Memorandum Account (WMPMA), the Catastrophic Event Memorandum Account (CEMA), the Land Conservation Plan Implementation Account (LCPIA) and the Residential Rate Reform Memorandum Account (RRRMA) included in this application. The revenue requirement calculation using the Results of Operations (RO) model presented here compile all capital costs and operating expenses to estimate the revenue that Pacific Gas and Electric Company (PG&E) needs to recover for work presented in this application. The revenue requirement for these costs is described below in Section B and sets forth in the tables at the end of this chapter. The revenue requirement for the final cost recovery will be calculated using the same RO assumptions presented here, updated as appropriate for interest expense, Revenue Fees and Uncollectible (RF&U), authorized Cost of Capital (COC), and tax parameters.

B. Summary of Request

In this application, PG&E seeks recovery of $1,280.7 million in total revenue requirement excluding interest for the period of 2017 through 2022. This amount consists of cumulative revenue requirement of $293.3 million for the FHPMA, $739.9 million for the FRMMA/WMPMA, $251.2 million for the CEMA, $0.077 million for the LCPIA and a $3.7 million refund to customers due to reduced spending for the RRRMA. In Section D of this chapter, PG&E explains the three cost recovery proposals given the pending Interim Rate Relief[1] Application.

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[1] Application (A.) 20-02-003.

In calculating the revenue requirement pursuant to this application, PG&E has removed the applicable amounts for activities that PG&E agreed to not seek cost recovery in accordance with the Decision of the Wildfires Order Instituting Investigation (I.19-06-015).

The FHPMA total revenue requirement of $293.3 million is associated with $293.3 million of expense incurred through 2019 and recorded in the FHPMA, as presented in Chapter 9, Table 9-1.

The FRMMA/WMPMA total revenue requirement of $739.9 million is associated with $720.3 million of expense and $592.4 million in capital expenditures incurred in 2019 and recorded in the FRMMA/WMPMA, as presented in Chapter 9, Table 9-1.

The CEMA total revenue requirement of $251.2 million is associated with $174.4 million of expense net of insurance proceeds and $209.6 million in capital expenditures in responding to certain CEMA events incurred in 2017, 2018 and 2019, as presented in Chapter 9, Table 9-1. As discussed in Chapter 9, the costs underlying the CEMA revenue requirement have been adjusted, in compliance with Public Utilities Code (Pub. Util. Code) Section 454.9, Resolution (Res.) E-3238, and Decision (D.) 08-01-021, to reflect only those costs not otherwise recovered through rates and incurred in counties that received a disaster declaration by a competent state or federal authority.

The other revenue requirement of $(3.7) million is associated with $0.077 million of expense recorded the LCPIA and $3.7 million refund to customers due to reduced spending in the RRRMA.

Table 10-1 at the end of this chapter presents the revenue requirement by each of the memorandum accounts described above. The revenue amount in this application excludes RF&U. When this application is approved by California Public Utilities Commission (CPUC or Commission), PG&E will update the revenue requirement to include RF&U in accordance with the Commission approved preliminary statement discussed in Section D in this chapter.

PG&E proposes to record the appropriate revenue requirement presented in this application into the Electric Distribution Revenue Adjustment Mechanism (DRAM), Portfolio Allocation Balancing Account (PABA) , Gas Core Cost Subaccount of the Core Fixed Cost Account (CFCA), and Noncore Subaccount of the Noncore Customer Class Charge Account (NCA).

C. Elements of the Results of Operations Calculation

Costs included in this application are based on the recorded amounts for the Wildfire mitigation programs, Catastrophic Events, and other memorandum accounts summarized in Chapter 1. The Chapters 2 through 8 testimony and workpapers supporting those chapters provide detailed description of these costs.

1. Expense

In this application, PG&E seeks to recover a total expense requirement of $1,184.4 million excluding interest. This amount is associated with the relevant expense of $293.3 million recorded in the FHPMA, $720.3 million recorded in the FRMMA/WMPMA, $174.4 million recorded in the CEMA for certain CEMA events included in this application, $0.077 million recorded in the LCPIA, and a $3.7 customer refund recorded in the RRRMA.

In accordance with the Wildfire OII Decision[2] PG&E has removed a total of $235.1 million of expense in calculating the wildfire mitigation expense revenue requirement. Specifically, PG&E has removed $34.7 million of expense related to accelerated wildfire risk reduction base camp costs and removed $200.4 million of expense related to Electric Distribution safety inspection and repairs.

The CEMA expense revenue requirement excludes employee benefits associated with labor expense incurred for the Catastrophic Events included in this application, as discussed in Chapter 9.

The expense-related revenue requirement is presented by year in Table 10-2 at the end of this chapter.

2. Capital

In this application, PG&E seeks to recover a total capital revenue requirement of $96.3 million. This amount is associated with the incremental capital expenditures of $592.4 million recorded in the FRMMA/WMPMA and $209.6 million recorded in the CEMA for certain CEMA events included in this application. There is no capital revenue requirement for the FHPMA, LCPIA, and the RRRMA.

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[2] I.19-06-015.

The capital-related revenue requirement is presented by year in Table 10-3 at the end of this chapter.

The capital revenue requirement is calculated based on the capital additions associated with the expenditures included in this application. Capital additions are incurred when PG&E spends funds on capital projects that are necessary to replace, augment or support its existing utility plant. In the case of the capital expenditures included in this filing, these expenditures were incurred to correct a loss of property or other damage to existing utility plant resulting from the identified Catastrophic Events or to install new utility plant or replace existing utility plant to mitigate wildfire risk. As discussed in Chapter 9, PG&E has excluded capitalized Administrative and General costs from CEMA capital expenditures in this filing.

As capital work happens, the costs are accumulated and recorded to Construction Work in Progress (CWIP) until the project is operational and providing utility service. While in CWIP, projects that last over 30 days accrue an Allowance for Funds Used During Construction (AFUDC). Projects that last less than 30 days do not accrue AFUDC and are treated as "operative as installed." When a specific capital project becomes operational, the CWIP balance is transferred to plant-in-service, and the capital expenditures and associated AFUDC become capital additions. Once a project is transferred to plant-in-service, it is included in rate base and a revenue requirement is calculated.

In calculating the capital revenue requirement in this application, PG&E has included recorded wildfire mitigation capital additions in 2019 and capital additions expected in 2020, 2021, and 2022 for capital expenditures recorded through 2019 and forecast to be operative in 2020-2022. These capital additions will become part of rate base and earn a revenue requirement the month it goes operational.

Res.E-3238 provides that "in addition to direct expense, utilities could also book capital-related costs such as depreciation and return on capitalized additions." Consistent with this resolution, PG&E's capital-related revenue requirement includes depreciation expense, a return on rate base, related federal and state income taxes, and property taxes.

The various capital-related components of the RO calculation are discussed below.

a. Depreciation

Depreciation is included in the revenue requirement calculation as both depreciation expense and accumulated depreciation. Depreciation expense is calculated on a straight-line, remaining-life method (in accordance with the Commission Standard Practice U-4, Determination of Straight Line Remaining Life Depreciation Accruals) using CPUC-approved rates from depreciation accrual rate schedules effective during the period for which the revenue requirement calculations are made. Depreciation expense is calculated by multiplying the weighted average plant in service by the corresponding book depreciation rates.

In this application, PG&E has used the 2017 General Rate Case (GRC) D.17-05-013 authorized depreciation rates for the years 2017-2022. PG&E will update the 2020-2022 depreciation expense calculated in this application based on the depreciation rates authorized in the final decision for PG&E's 2020 GRC, which is currently pending.

b. Rate of Return on Rate Base

Rate base is calculated using utility plant less adjustments for deferred taxes and depreciation reserve. Utility plant consists of the original cost of investment in plant and equipment that is used and useful in rendering or restoring utility services. In developing the rate base associated with that plant for purposes of this filing, certain deductions are made. A reduction is made for the accumulated deferred income taxes associated with these assets. These deferred income taxes primarily result from following the Modified Accelerated Cost Recovery System (MACRS) tax depreciation method and casualty loss deductions for Federal Income Tax (FIT) purposes. Rate base is reduced by the amount of depreciation reserve (i.e., the accumulated depreciation already taken in prior years).

PG&E multiplies the currently adopted composite Rate of Return (ROR) by the weighted average rate base for each year to calculate the

Net for Return. This calculation uses the ROR and capital structure adopted in PG&E's 2013 authorized Cost of Capital decision for year 2017[3], the 2018 authorized COC decision for years 2018-2019,[4] and the 2020 authorized COC decision for years 2020-2022.[5] On August 20, 2020, CPUC approved PG&E's Advice letter 4275-G/5887-E (Tier 2) to update its COC effective July 1, 2020. This application uses the updated cost of debt from this advice letter. Section C below explains the ROR applied to Wildfire mitigation rate base.

c. Assembly Bill 1054 Return on Wildfire Costs

Pursuant to the Assembly Bill (AB) 1054 passed on July 12, 2019 by Governor Newsom, large electrical corporations are prohibited from including in equity rate base their share of the first $5 billion spent statewide on fire risk mitigation capital expenditures[6] in their approved Wildfire Mitigation Plans. PG&E's allocation of the $5 billion in capital expenditures pursuant to the initial allocation metric is $3.21 billion.[7] PG&E's capital expenditures that count towards the $3.21 billion in wildfire risk mitigation capital expenditures are those that are recorded in the FRMMA/WMPMA and Community Wildfire Safety Program forecast in the 2020 GRC. PG&E must apply a debt return to additions to rate base as described in Pub. Util. Code Section 8386.3 (e). Subsequently on November 1, 2019, PG&E filed the AB 1054 brief with the CPUC to seek approval of the costs subject to the modified return. PG&E asked for Commission's approval to include wildfire mitigation costs starting August 2019 for the modified return. PG&E is yet to receive a final decision on this filing.

The ROR that PG&E applied to the AB 1054 equity rate base in this application is as follows: the cost of capital bond debt ratio was increased from 47.5 percent to 99.5 percent and the cost of equity ratio

3 D.12-12-034.

4 D.17-07-005.

5 D.19-12-056.

6 Capital expenditures include capital additions and cost of removal.

7 As noted above in Section 3280, this amount is subject to later adjustment if the administrator of the Wildfire Fund publishes a revised Wildfire Fund allocation metric.

was decreased from 52 percent to 0 percent. The preferred stock ratio remained unchanged at 0.5 percent.

Table 9-1 shows the FRMMA/WMPMA costs starting August 2019 adjusted to remove the cost of equity from the AFUDC.

d. Income Tax and Depreciation Assumptions

This section describes the assumptions and calculations used in the revenue requirement calculation to estimate depreciation for income tax purposes.

PG&E estimates current California Corporation Franchise Taxes and FIT on net operating income before income taxes. PG&E follows MACRS and Asset Depreciation Range[8] guidelines for classifying capital additions and calculating federal and state tax depreciation. Current FIT expense is the product of the currently effective corporate income tax rate, 21 percent, and federal taxable income. Likewise, current state income tax expense is the product of the statutory rate (8.84 percent) and the state taxable income. Both MACRS and federal casualty loss tax deductions are computed on a normalized basis. This allows PG&E to recognize the timing differences between book and these federal tax deductions. This difference multiplied by the federal tax rate is called deferred FITs, and is included as an adjustment to current federal tax expense and a credit to rate base. State income taxes are calculated on a flow-through basis. Therefore, customers receive an immediate benefit from the use of accelerated state tax deductions. There are no deferred state taxes and therefore no associated deduction to rate base.

The 2017 Tax Cuts and Jobs Act (TCJA) reduced the FIT rate from 35 percent to 21 percent, which resulted in remeasurement of deferred taxes associated with capital additions placed in service prior to 2018 from 35 percent to 21 percent as of December 31, 2017. The 14 percent excess will be refunded to ratepayers in accordance with normalization requirements. Depreciation related tax timing differences giving rise to excess tax reserves are required to be amortized using the

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8 Uses Sum of Years Digits method.

Average Rate Assumption Method (ARAM) under the normalization rules. The ARAM requires that excess tax reserves be refunded to customers over the regulatory book life of the underlying assets that generated the original tax reserves. TCJA stipulates that the refunding of excess tax reserves more rapidly or to a greater extent than such reserve would be reduced under the ARAM results in a normalization violation. PG&E proposes to use the ARAM to amortize plant-related excess deferred taxes.

The capital expenditures included in this filing were incurred to correct a loss of property or other damage to existing utility plant resulting from an identified catastrophic event. Certain capital costs qualify for casualty loss tax treatment. Internal Revenue Code Section 165(a) allows a deduction for any loss sustained during the taxable year that is not compensated for by insurance or otherwise. In accordance with Revenue Ruling 87-117 and Chief Counsel Advice 201145011, the potential recovery of storm and fire costs requested in a filing with the CPUC is not considered compensation for the casualty loss under Section 165(a) (however any potential recovery will be included in gross income in the future if and when received). Treas. Reg. Section 1.165-1(b) provides that to be allowable as a deduction under Section 165(a), a loss must be evidenced by closed and completed transactions, fixed by identifiable events, and related to disaster losses actually sustained during the taxable year. The amount of loss to be taken into account for purposes of Section 165(a) shall be the lesser of either:

i) The amount which is equal to the fair market value of the property immediately before the casualty reduced by the fair market value of the property immediately after the casualty; or
ii) The amount of the adjusted basis prescribed in Treas. Reg. Section 1.1011-1 for determining the loss from the sale or other disposition of the property involved.

Under Treas. Reg. Section 1.165-7(a)(2)(ii), the cost of repairs (both capital and expense) to the property damaged is acceptable as evidence of the loss of value. However, Treas. Reg.

Section 1.263(a)-(3)(k)(1)(iii), requires the taxpayer to capitalize the expense component resulting in net tax deduction of the capital restoration costs. Since these Catastrophic Event costs are capitalized for book purposes and deducted for tax purposes, a book-tax adjustment is created. As described above, in this filing, federal depreciation and casualty loss deduction book-tax adjustments are computed on a normalized basis, while state book-tax differences are calculated on a flow-through basis.

Cost capitalized for book purposes that do not qualify for tax casualty loss deductions may qualify for the tax repair deduction. Federal and California tax repair deductions are treated on a flow-through basis. PG&E applies Treasury Regulations under Sections 162 and 263(a) to deduct costs attributable to repairs and maintenance of gas transmission and distribution lines. PG&E applies Internal Revenue Service (IRS) Revenue Procedures 2011-43 and 2013-24 to deduct costs attributable to repairs and maintenance of electric distribution circuits and electric generation plants. The IRS guidance allows a more expansive "unit of property" definition for tax purposes than for financial reporting purposes. This allows PG&E to treat certain expenditures as a current repair expense. For financial reporting purposes, these expenditures are capitalized and depreciated. Thus, a tax and book basis timing difference is created.

e. Property Taxes

Property tax calculations are determined by multiplying the taxable Plant Less Depreciation (Net Plant) by the composite property tax factor for 2017-2022. The property tax factor is comprised of the adjusted base year market-to-cost ratio multiplied by the composite tax rate. The adjusted market-to-cost ratio is the relationship between the most current assessment (adjusted) and the taxable Net Plant.

D. Cost Recovery

PG&E is presenting the following cost recovery proposals depending on whether PG&E's Interim Rate Relief request is granted. In accordance with Ordering Paragraph 3 of the September 18, 2020 Proposed Decision in

A.20-02-003, Table 10-5 compares the amount of interim rate relief granted in the ratemaking scenarios below with the revenue requirement sought in this application.

1. Preferred Scenario

PG&E's preferred scenario assumes that PG&E's Interim Rate Request of $891 million is approved, which would leave a remaining $422.5 million (including interest of $32.9 million) revenue requirement for recovery. In this preferred scenario, PG&E proposes to recover the remaining revenue requirement over a 12-month period, following the conclusion of interim rate relief recovery starting June 2022, or as soon as practicable following a final decision. PG&E believes this proposal would provide rate stability while reducing the financing costs to customers. In this scenario, the typical residential electric customer would see his/her bill increase by approximately $3.55 per month over currently effective rates. This would result in a net decrease from the level requested through interim rates. The typical residential gas customer would see his/her bill increase by approximately $0.10 per month.

2. Alternative Scenario 1

On September 18, 2020, CPUC issued a proposed decision on PG&E's interim rate relief application—A.20-02-03—which adopted $447.0 million of rate recovery over a 17-month period from January 2021 to May 2022. If the Commission adopts this proposed decision, PG&E requests to collect the remaining $868.4 million of revenue requirement (including interest of $34.8 million) over a 12 month period from June 2022 to May 2023, after the conclusion of interim rate relief recovery. PG&E respectfully requests a 12-month recovery as the timely recovery of the wildfire mitigation costs presented in this application will strengthen PG&E's credit rating and cash flow and its ability to service its debt, thereby benefitting customers with a lower interest rate on its debt. In this scenario, the typical residential electric customer would see his/her bill increase by approximately $7.64 per month over currently effective rates. This would result in a net increase from the level authorized in the interim rate relief proposed decision. The typical residential gas customer would see his/her bill increase by approximately $0.10 per month.

3. Alternative Scenario 2

PG&E's alternative Scenario 2 assumes that no Interim Rate Relief is granted. In this scenario, PG&E proposes to recover the entire $1,320 million revenue requirement (including interest of $39.4 million) over a 24-month period, starting January 2022, or as soon as practicable following a final decision. In this scenario, the typical residential electric customer would see his/her bill increase by approximately $5.82 per month over currently effective rates. The typical residential gas customer would see his/her bill increase by approximately $0.05 per month.

PG&E's final cost recovery will include the interest expense based on the applicable interest rates, timing of the decision and the adopted cost recovery scenario.

In the final stages of preparation of this case we have identified some minor amounts that were included in the RO model that should not have been included. These will be removed in future runs of the model. Furthermore, future errors and adjustments that are discovered through the litigation of the case will be included in the revenue requirement update, as appropriate.

Consistent with past practice, PG&E proposes to roll the FRMMA/WMPMA and CEMA-eligible capital into rate base in its 2023 GRC. The revenue requirement associated with the recorded costs included in this application are not included in PG&E's 2020 GRC or in any other cost recovery mechanism or otherwise adopted as part of current authorized rates.

The revenue requirement calculation in this filing excludes RF&U. Upon CPUC approval of the cost recovery in this application, the revenue requirement associated with the approved costs in this filing will be posted monthly into the specific memorandum accounts and will include interest and RF&U. PG&E will accrue interest associated with authorized revenue requirement based on the latest available interest rates, consistent with the Commission-approved preliminary statement which provides for the applicable "interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, G.13, or its successor."[9]

PG&E proposes to recover all approved incremental expenditures through the DRAM, PABA, CFCA, and NCA rate mechanisms as part of the Annual Electric True-Up (AET) and Annual Gas True-Up (AGT) advice letter filings on January 1, 2022, or the next available rate change after the effective date of the decision in this proceeding, and through the AET and AGT thereafter. Rates set to recover costs in this application will be determined in the same manner as rates set to recover other Electric Distribution, Power Generation, Gas Distribution and Gas Transmission costs, using adopted methodologies for revenue allocation and rate design. The change in rates for approved recovery of recorded costs included in this application will affect total charges for bundled service customers and for customers who purchase energy from other suppliers (i.e., direct access and community choice aggregation customers).

E. Conclusion

PG&E respectfully requests that the Commission adopt a total revenue requirement of $1,280.7 million (excluding interest) or $1,313.0 million (preferred scenario including interest). The revenue requirement set forth in this filing is calculated using the RO model for separately funded rate case applications and is based on the recorded costs presented and included in other testimony submitted in this filing. The revenue requirement calculation is provided in the workpapers supporting this chapter.

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9 https://www.pge.com/tariffs/tm2/pdf/ELEC_PRELIM_G.pdf; https://www.pge.com/tariffs/tm2/pdf/GAS_PRELIM_AC.pdf.

TABLE 10-1
REVENUE REQUIREMENT – SUMMATION OF ALL YEARS (2017-2022)[(a)]
(THOUSANDS OF DOLLARS)

Line No.		Electric Distribution			Power Generation			Gas Distribution			Gas Transmission			Total Functional Areas		
		(2017-2022)			(2017-2022)			(2017-2022)			(2017-2022)			(2017-2022)		
		Expense	Capital	Total	Expense	Capital	Total	Expense	Capital	Total	Expense	Capital	Total	Expense	Capital	Total
	Event															
1	FHPMA (2010 - 2019)	293,269	0	293,269	-	-	-	-	-	-	-	-	-	293,269	0	293,269
2	FRMMA / WMPMA	718,113	19,549	737,662	2,213	-	2,213	-	-	-	-	-	-	720,325	19,549	739,874
3	2018 Carr Fire	491	(898)	(407)	-	-	-	133	82	215	-	-	-	623	(816)	(192)
4	2019 Jan and Feb severe storm	97,286	31,881	129,166	697	954	1,650	703	109	812	-	-	-	98,685	32,943	131,629
5	2019 Ridgercerest Eq	-	-	-	-	-	-	2,824	21	2,845	35	487	521	2,859	508	3,367
6	2019 October Wind/PSPS Event	7,209	2,633	9,842	-	-	-	-	-	-	-	-	-	7,209	2,633	9,842
7	2019 Bethel Island Fire	0	10	10	-	-	-	-	-	-	-	-	-	0	10	10
8	2019 Camino Fire	-	4	4	-	-	-	-	-	-	-	-	-	-	4	4
9	2019 Glencove Fire	-	80	80	-	-	-	-	-	-	-	-	-	-	80	80
10	2017 Cherokee Fire	80	73	154	-	0	0	-	-	-	-	-	-	80	73	154
11	2017 La Porte Fire	56	454	510	-	-	-	-	0	0	-	-	-	56	454	510
12	2017 Tubbs Fire	55,273	35,413	90,686	-	-	-	9,578	5,441	15,019	68	0	68	64,919	40,854	105,773
13	Land Conservation Plan	-	-	-	77	0	77	-	-	-	-	-	-	77	0	77
14	RRRMA Residential Rate Reform	(3,738)	(0)	(3,738)	-	-	-	-	-	-	-	-	-	(3,738)	(0)	(3,738)
15	Subtotal - Recorded without Interest	1,168,038	89,199	1,257,237	2,986	954	3,940	13,238	5,653	18,891	103	487	589	1,184,365	96,293	1,280,657
16	Total RRQ (without Interest)	**1,168,038**	**89,199**	**1,257,237**	**2,986**	**954**	**3,940**	**13,238**	**5,653**	**18,891**	**103**	**487**	**589**	**1,184,365**	**96,293**	**1,280,657**
17	Preferred Scenario - Interest	32,282	(966)	31,316	29	5	35	1,477	33	1,511	5	1	6	33,794	(926)	32,867
18	Alternative Scenario 1 - Interest	34,161	(906)	33,254	29	5	35	1,477	33	1,511	5	1	6	35,672	(866)	34,806
19	Alternative Scenario 2 - Interest	38,530	(774)	37,755	31	7	38	1,506	45	1,551	5	2	7	40,072	(720)	39,352
20	**Total RRQ - Preferred Scenario**	**1,200,320**	**88,233**	**1,288,553**	**3,015**	**959**	**3,974**	**14,715**	**5,687**	**20,402**	**108**	**488**	**595**	**1,218,158**	**95,366**	**1,313,525**
21	**Total RRQ - Alternative Scenario 1**	**1,202,198**	**88,293**	**1,290,491**	**3,015**	**959**	**3,974**	**14,715**	**5,687**	**20,402**	**108**	**488**	**595**	**1,220,037**	**95,427**	**1,315,463**
22	**Total RRQ - Alternative Scenario 2**	**1,206,568**	**88,425**	**1,294,992**	**3,017**	**961**	**3,978**	**14,744**	**5,698**	**20,442**	**108**	**489**	**597**	**1,224,437**	**95,572**	**1,320,009**

TABLE 10-2
EXPENSE REVENUE REQUIREMENT – SUMMARY BY YEAR (2017-2022)
(THOUSANDS OF DOLLARS)

Line No.	Annual RRQ without Interest	Electric Distribution Expense RRQ	Power Generation Expense RRQ	Gas Distribution Expense RRQ	Gas Transmission Expense RRQ	Total Functional Area Expense RRQ
1	2017	30,085	68	19,460	56	49,669
2	2018	296,817	7	5,929	12	302,764
3	2019	847,804	2,912	6,180	35	856,931
4	2020	(6,669)	-	(18,331)	-	(25,000)
5	2021	-	-	-	-	-
6	2022	-	-	-	-	-
7	**Total (without interest)**	**1,168,038**	**2,986**	**13,238**	**103**	**1,184,365**
8	Preferred Scenario - Interest	32,282	29	1,477	5	33,794
9	Alternative Scenario 1 - Interest	34,161	29	1,477	5	35,672
10	Alternative Scenario 2 - Interest	38,530	31	1,506	5	40,072
11	**Total RRQ - Preferred Scenario**	**1,200,320**	**3,015**	**14,715**	**108**	**1,218,158**
12	**Total RRQ - Alternative Scenario 1**	**1,202,198**	**3,015**	**14,715**	**108**	**1,220,037**
13	**Total RRQ - Alternative Scenario 2**	**1,206,568**	**3,017**	**14,744**	**108**	**1,224,437**

TABLE 10-3
CAPITAL REVENUE REQUIREMENT – SUMMARY BY YEAR (2017-2022)
(THOUSANDS OF DOLLARS)

Line No.	Annual RRQ without Interest	Electric Distribution Capital RRQ	Power Generation Capital RRQ	Gas Distribution Capital RRQ	Gas Transmission Capital RRQ	Total Functional Area Capital RRQ
1	2017	(3,907)	(0)	123	(0)	(3,784)
2	2018	1,069	(5)	644	11	1,719
3	2019	(85,299)	(4)	(2,008)	(175)	(87,487)
4	2020	63,099	350	2,582	255	66,286
5	2021	57,346	303	2,160	196	60,005
6	2022	56,891	310	2,153	200	59,554
7	**Total**	**89,199**	**954**	**5,653**	**487**	**96,293**
8	Preferred Scenario - Interest	(966)	5	33	1	(926)
9	Alternative Scenario 1 - Interest	(906)	5	33	1	(866)
10	Alternative Scenario 2 - Interest	(774)	7	45	2	(720)
11	**Total RRQ - Preferred Scenario**	**88,233**	**959**	**5,687**	**488**	**95,366**
12	**Total RRQ - Alternative Scenario 1**	**88,293**	**959**	**5,687**	**488**	**95,427**
13	**Total RRQ - Alternative Scenario 2**	**88,425**	**961**	**5,698**	**489**	**95,572**

TABLE 10-4
TOTAL REVENUE REQUIREMENT – SUMMARY BY YEAR (2017-2022)
(THOUSANDS OF DOLLARS)

Line No.	Annual RRQ and Interest	Electric Distribution RRQ	Power Generation RRQ	Gas Distribution RRQ	Gas Transmission RRQ	Total Functional Area RRQ
1	2017	26,178	68	19,583	56	45,885
2	2018	297,886	1	6,573	23	304,483
3	2019	762,506	2,907	4,172	(141)	769,444
4	2020	56,430	350	(15,750)	255	41,286
5	2021	57,346	303	2,160	196	60,005
6	2022	56,891	310	2,153	200	59,554
7	**Subtotal - Without Interest**	**1,257,237**	**3,940**	**18,891**	**589**	**1,280,657**
8	Preferred Scenario - Interest	31,316	35	1,511	6	32,867
9	Alternative Scenario 1 - Interest	33,254	35	1,511	6	34,806
10	Alternative Scenario 2 - Interest	37,755	38	1,551	7	39,352
11	**Total RRQ - Preferred Scenario**	**1,288,553**	**3,974**	**20,402**	**595**	**1,313,525**
12	**Total RRQ - Alternative Scenario 1**	**1,290,491**	**3,974**	**20,402**	**595**	**1,315,463**
13	**Total RRQ - Alternative Scenario 2**	**1,294,992**	**3,978**	**20,442**	**597**	**1,320,009**

TABLE 10-5
INTERIM RATE RELIEF – REVENUE REQUIREMENT
(THOUSANDS OF DOLLARS)

Ln No	Account	Revenue Requested in this application	Interim Rate Relief Revenue Request	Interim Rate Relief-Proposed Decision	Revenue Requirement - Preferred Scenario	Revenue Requirement - Alternative Scenario 1
		(A)	(B)	(C)	(D)=(A)-(B)	(E)=(A)-(C)
1	FHPMA	293,269	253,938	164,197	39,331	129,072
2	FRMMA/WMPMA	739,874	407,332	263,382	332,542	476,492
3	CEMA	251,175	192,748	-	58,427	251,175
4	LCPIA	77	-	-	77	77
5	RRRMA	(3,738)	-	-	(3,738)	(3,738)
6	**Total excluding interest**	**1,280,657**	**854,018**	**427,579**	**426,639**	**853,078**
7	Interest in Preferred Scenario	32,867	36,981	-	(4,113)	-
8	Interest in Alternative Scenario 1	34,806	-	19,455	-	15,351
9	**Total Revenue Requirement including interest - Preferred Scenario**	**1,313,525**	**890,999**	**-**	**422,526**	**-**
10	**Total Revenue Requirement including interest - Alternative Scenario 1**	**1,315,463**	**-**	**447,035**	**-**	**868,429**

PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

STATEMENTS OF QUALIFICATIONS

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF EMILY BARTMAN

Q 1 Please state your name and business address.

A 1 My name is Emily Bartman, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Chief Product Manager in the Pricing Products Department. My responsibilities include representing customer needs while identifying, addressing, and communicating potential business and operational impacts from new rate proposals. In addition, I serve as the witness for Pricing Products' General Rate Case Phase I and Rate Reform Cost Recovery proceedings.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Mathematical Economics from Pomona College in 1986, and a Master's degree in Business Administration from the University of California at Berkeley in 1992. I have worked at PG&E since 2011, as a Principal Product Manager for pricing products before I was promoted to my current position in July 2020. Prior to that, I worked as an independent consultant for nine years including four years at Southern California Edison Company (SCE), analyzing and synthesizing existing customer research to help drive strategic planning efforts. Between 1994 and 1999, I worked for Edison International, first building a customer-focused market analysis and strategy organization at SCE, later helping launch the unregulated affiliate Edison Enterprises from the corporate center, and then building a direct marketing organization at Edison Source. From 1988 to 1990 and 1999 to 2002, I worked for the PA Consulting Group (also PHB Hagler Bailly and Theodore Barry and Associates) in the retail strategy group.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 7, “2017-2019 Residential Rate Reform Memorandum Account Costs”;
- Workpapers supporting Chapter 7.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF SANDRA CULLINGS

Q 1 Please state your name and business address.

A 1 My name is Sandra Cullings, and my business address is Pacific Gas and Electric Company, 1850 Gateway Boulevard, Concord, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Director of the Core Programs for Major Project and Programs, Electric Distribution and Transmission, including Wildfire Mitigation.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Arts degree in Political Science from California State University, Stanislaus. I have been employed in a variety of operational and supervisory positions at PG&E since 2000. More recently, I was the Senior Manager responsible for the end-to-end process for Internal Work and the Rule 20A Program (2018-2019); Senior Manager of Planning, Scheduling and Controls for Major Projects and Programs (2016-2018); Senior Manager of Distribution Work and Program Management (2015-2016); and the Rotation Director for Strategic Business Management, responsible for transmission and distribution resource planning (2014-2015).

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 2, "Electric Distribution: Wildfire Mitigation Activities":
  - Sections B.1.a and B.2; and
- Workpapers supporting Chapter 2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ANGELINA M. GIBSON

Q 1 Please state your name and business address.

A 1 My name is Angelina M. Gibson, and my business address is Pacific Gas and Electric Company, 2641 N State Street, Ukiah, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am Director of Emergency Preparedness and Response Strategy & Execution in the Electric Distribution organization. Prior to my current role, I was the Manager of the Emergency Management and Public Safety Department.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Public Safety Administration from Franklin University, Columbus, Ohio, in 2004. I am a Disaster Science Fellow of the Academy of Emergency Management. I have held numerous positions within PG&E's emergency response process since 1995 and have been employed in a variety of bargaining unit and management positions at PG&E since 1988.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 2, "Electric Distribution: Wildfire Mitigation Activities":
  - Section B.4 and B.5; and
- Workpapers supporting Chapter 2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DAVE LEVIE

Q 1 Please state your name and business address.

A 1 My name is Dave Levie, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E or the Company).

A 2 I am a Manager in the Revenue Requirements and Cost Analysis team and I oversee the operating and maintenance, and administrative and general cost inputs into our cost recovery applications. The team and I are also responsible for ensuring that the Company is in compliance with the Federal Energy Regulatory Commission and the California Public Utilities Commission reporting requirements. We prepare analytics, insights, and recommendations that enable informed decision-making by PG&E senior management.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Accounting from the University of Arizona in 2005 and became a Certified Public Accountant in California in 2008 (current status is inactive). Prior to PG&E, I was an Auditor for PricewaterhouseCoopers. Since joining PG&E in 2009, I have held various positions in our Corporate and Capital Accounting departments that centered around cost recovery, balancing accounts, and maintaining key controls and financial inputs into our rate base. For the last two years, I have directly supported our regulatory filings.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 9, "Accounting Adjustments";
- Workpapers supporting Chapter 9.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF VISHWANATH NATARAJAN

Q 1 Please state your name and business address.

A 1 My name is Vishwanath Natarajan, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Senior Director of the Products and Enterprise Platforms Department in the Information Technology (IT) organization. My department is responsible for the management, development and support of IT software applications used by resources in Electric Operations, the Wildfire Safety Program, and Geographical Information Systems Departments.

Q 3 Please summarize your educational and professional background.

A 3 In 1991, I received a Bachelor's degree in Electronics and Communication Engineering from Bharathiar University from Coimbatore, India. With respect to my professional background, I have been in the IT field for over 25 years working in Telecommunications, Financial and Banking industries. Since 2016, I have worked at PG&E as the Senior Director in IT, responsible for IT software applications supporting the Customer Care organization. In 2019, I subsequently acquired the responsibility for the management, development and support of IT software applications in support of the Community Wildfire Safety Program which led to my current role in 2020. Prior to PG&E, I was a Senior Vice President in IT for SunTrust Bank for three years. In this position, I was responsible for supporting the Digital Channels Technology organization for the bank. Prior to that, I led the Technology Application Development organization for Allconnect, a consumer services company partnering with utilities across the United States.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 6, "Information Technology Costs"; and
- Workpapers supporting Chapter 6.

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MATTHEW T. PENDER

Q 1 Please state your name and business address.

A 1 My name is Matthew T. Pender, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Director of Electric Regulatory Strategy, the Community Wildfire Safety Plan (CWSP) Program Management Office (PMO) and Wildfire Plans. My team is responsible for Electric Operations' regulatory proceedings and activities that support the safe, efficient and transparent execution of PG&E's Wildfire Safety Plans. This includes managing the submission of Wildfire Mitigation Plans and the associated requirements to report on the execution of the plans.

Q 3 Please summarize your educational and professional background.

A 3 I attended North Carolina State University and earned Bachelor of Science degrees in Mechanical Engineering and Business Management. I have worked at PG&E since 2006 as a Gas Distribution Engineer, a Gas Program Manager, Manager and Director of Electric Performance Management, Director of Land Management, Director in Vegetation Management and now Director of Electric Regulatory Strategy, CWSP PMO and Wildfire Plans. While working at PG&E, I obtained my license as a Professional Engineer in the State of California (Mechanical Engineering, specifically) and I also earned my master's degree in Business Administration from the University of Pennsylvania's Wharton School of Business.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 2, "Electric Distribution: Wildfire Mitigation Activities":
  - Sections A and C.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DEBBIE W. POWELL

Q 1 Please state your name and business address.

A 1 My name is Debbie W. Powell, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am Vice President, Asset, Risk Management & Communications Wildfire Safety Program in PG&E's Electric Operations Organization.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in General Science from the United States (U.S.) Naval Academy in 1990.

I served in the U.S. Navy from 1990-2003. I served in various leadership positions during this time including Main Propulsion Assistant of the USS Gettysburg; Chief Engineer of the USS Cole and USS Arthur W. Radford; and a Joint Forces Command Staff Officer.

I worked in various capacities at Dell, Inc. from 2003-2006 including Facilities Engineering and Maintenance Manager and Business Continuity and Recovery Planning Program Global Manager.

I worked at the Lower Colorado River Authority from 2006-2010 as the Plant Manager of a natural gas fired power plant. In this position, I was responsible for plant performance, operations, and environmental and safety compliance.

I joined PG&E's Power Generation organization in May 2010 as a Director responsible for the operations and maintenance of the fossil generation assets. In January 2012, I became the Director responsible for the operations and maintenance of the hydroelectric generation assets.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 1, "Introduction and Overview";
- Workpapers supporting Chapter 1.

Q 5 Does this conclude your statement of qualifications?
A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF DIVYA RAMAN

Q 1 Please state your name and business address.

A 1 My name is Divya Raman, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am a Manager in the Financial Forecasting and Revenue Requirements section of the Finance and Risk Department, where I am responsible for producing and supervising the preparation of revenue requirement models and sponsoring related testimony.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science degree in Management from Birla Institute of Technology and Science, India in 2005. I also received my Master of Science degree in Finance from London Business School in 2009. I also have the Chartered Financial Analyst certification.

I started my career in PG&E in 2012 as a Senior Analyst in Capital Recovery and analysis team and promoted to Expert Analyst in 2013. My responsibilities included analysis and presentation of Depreciation Expense, Plant and Rate base in various rate cases. I was the Plant and Ratebase, Depreciation Expense witness in PG&E's first formula rate Transmission Owner filing.

In 2018, I was promoted to Principal Analyst in the Financial Forecasting and Revenue Requirements team. My focus in this position included reviewing PG&E's revenue requirement in the 2019 Gas Transmission and Storage, 2020 General Rate Case, as well as PG&E's 2018 and 2019 Catastrophic Event Memorandum Account filings. In 2020, I was promoted to Manager of the Revenue Requirement and Regulatory Results of Operations team. My responsibilities in this position include production and supervision of revenue requirement calculations for regulatory filings and being the expert witness for revenue requirements.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2020 Wildfire Mitigation and Catastrophic Events:

- Chapter 10, "Revenue Requirement"; and
- Workpapers supporting Chapter 10.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF STEVE ROYALL

Q 1 Please state your name and business address.

A 1 My name is Steve Royall, and my business address is Pacific Gas and Electric Company, 245 Market Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Director for Operations and Maintenance of PG&E's generation facilities in the northern portion of our system in PG&E's Power Generation organization.

Q 3 Please summarize your educational and professional background.

A 3 I joined PG&E in 2007 as Director in the Generation Department, responsible for managing the Gateway Generating Station. Prior to PG&E, I worked at the Northern California Power Agency, where I was the Assistant General Manager of Power Generation and the Manager of Gas Fired Generation. I have more than 37 years of experience working in power generation projects in the areas of operation, engineering, construction, and commissioning. I have been involved in projects that resulted in approximately 3,500 megawatts of new generation in California and Washington over the last 37 years, including PG&E's new Gateway Generating Station, and Colusa Generating Station. Other former employers include: (1) Calpine Corporation; (2) Phillips Oil Company; and (3) Freeport McMoRan Corporation. I am the Chairperson of the Electric Utility Cost Group Fossil committee and the former chairman of the Combined Cycle Users Group.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 5, "Power Generation"; and
- Workpapers supporting Chapter 5.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MATT SANDERS

Q 1 Please state your name and business address.

A 1 My name is Matt Sanders, and my business address is Pacific Gas and Electric Company, 1535 Bonanza Street, Walnut Creek, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Director of Vegetation Management Program Management. This includes providing portfolio management and controls for the entire Vegetation Management program enabling Vegetation Management operations to ensure the safety, reliability, and regulatory compliance with state and federal rules. In addition, I provide strategic direction over the Vegetation Management Standards and Procedures and ensure adequate training and communication is performed to enable our Vegetation Management workforce to provide quality in their work.

Q 3 Please summarize your educational and professional background.

A 3 I have a Bachelor of Science degree in Industrial Engineering from California Polytechnic State University, San Luis Obispo, California. In addition, I have attended the Stanford Executive Leadership Program and obtained my Project Management Professional certification from the Project Management Institute. I have had a 14-year career at PG&E spanning roles in Portfolio & Project Management, General Construction, Finance, Corrective Action Program, and Asset Risk Management. Prior to PG&E, I had engineering roles at Boeing Commercial Airplanes, Frederickson, Washington, and the Contra Costa Water District, Concord, California.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E’s 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 2, “Electric Distribution: Wildfire Mitigation Activities”:
  - Sections B.3; and
- Workpapers supporting Chapter 2.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF ANDREW WELLS

Q 1 Please state your name and business address.

A 1 My name is Andrew Wells, and my business address is Pacific Gas and Electric Company, 6121 Bollinger Canyon Road, San Ramon, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Manager of Emergency Preparedness in the Gas System Operations organization. The Gas Emergency Preparedness (GEP) team consists of staff tasked with developing and maintaining the Gas Emergency Response Plan (GERP). The Emergency Preparedness Team is responsible for: (1) developing and delivering training related to the GERP; (2) creating and delivering challenging exercises to ensure emergency center teams maintain skills in emergency response; (3) and supporting emergencies in the field when they occur. As the Manager, I am responsible for ensuring the GEP team accomplishes its mission. In addition, I represent PG&E on the board of directors for the Underground Service Alliance of California and Nevada, the non-profit organization that operates the 8-1-1 call center for Northern California and Nevada.

Q 3 Please summarize your educational and professional background.

A 3 I hold a Bachelor of Science degree in Fire Service Administration Technology, and have performed work in the emergency preparedness and/or response fields for the past 29 years. My experience includes working in incident management roles in the: (1) Los Angeles County Fire Department, (2) Pechanga Fire Department, (3) Sierra Madre Fire Department, and (3) San Onofre Nuclear Generating Station, as a Project Manager on the emergency preparedness team. During my 6-year tenure at PG&E, I have managed and supervised emergency preparedness teams and programs, as well as running several damage prevention and public awareness programs.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 4, “Gas”;
- Attachment A, “Additional Material”; and
- Workpapers supporting Chapter 4.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF MATT WHORTON

Q 1 Please state your name and business address.

A 1 My name is Matt Whorton, and my business address is Pacific Gas and Electric Company, 77 Beale Street, San Francisco, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Director of the Business Finance Electric Operations Department who directly supports the Financial Planning and Analysis activities of PG&E's electric business.

Q 3 Please summarize your educational and professional background.

A 3 I received my Bachelor of Science in Microbiology from the University of California at Davis and my Master of Business Administration (MBA) from the University of San Francisco. Upon receiving my MBA, I began work at PG&E 11 years ago and have had numerous roles within the Finance Organization.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony in PG&E's 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 8, "Demonstration of Incrementality"; and
- Attachment A, "Ernst & Young Cost Analysis."

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.

PACIFIC GAS AND ELECTRIC COMPANY
STATEMENT OF QUALIFICATIONS OF THOMAS J WRIGHT, JR.

Q 1 Please state your name and business address.

A 1 My name is Thomas J Wright, Jr., and my business address is Pacific Gas and Electric Company, 6111 Bollinger Canyon Road, San Ramon, California.

Q 2 Briefly describe your responsibilities at Pacific Gas and Electric Company (PG&E).

A 2 I am the Process Owner of Emergency/Restoration in the Electric Distribution organization. The Emergency/Restoration organization consists of the Emergency Management group, Emergency Recovery Program, and the Damage Claims. The Emergency Management team is responsible for: developing response processes to emergency incidents; training and preparing PG&E's electric organization to provide efficient responses to emergencies and catastrophic disasters; and direct support of emergency response. The Emergency Recovery group is responsible for the electric emergency response work, which most often entails responding to outages. I am responsible for: allocating funding for emergency response in all 19 PG&E divisions; monitoring financial and work performance; providing technical direction; optimizing system spending and resource allocation; and working with asset owners to support area investment strategy. The Damage Claims team is responsible for recovery costs for damages to PG&E's facilities from third parties.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science degree in Electrical Engineering from the University of Arkansas in Fayetteville, Arkansas in 1992 and a Master's of Science in Engineering Management from the University of New Orleans in New Orleans, Louisiana in 2000. I have been with PG&E since 2010 holding several positions in operations and asset management. In 2018 and 2019, I led the Wildfire Safety Inspection Program for PG&E's Transmission Assets.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony and workpapers in PG&E's 2020 Wildfire Mitigation and Catastrophic Events Application:

- Chapter 2, "Electric Distribution: Wildfire Mitigation Activities":
  - Section B.1.a;
- Workpapers supporting Chapter 2;
- Chapter 3, "Electric Distribution: CEMA"; and
- Workpapers supporting Chapter 3.

Q 5 Does this conclude your statement of qualifications?

A 5 Yes, it does.