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Date: May 15, 2025
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PACIFIC GAS AND ELECTRIC COMPANY

2027 GENERAL RATE CASE

PREPARED TESTIMONY

EXHIBIT (PG&E-4)

ELECTRIC DISTRIBUTION

CHAPTERS 1-9

VOLUME 1 OF 2

PACIFIC GAS AND ELECTRIC COMPANY
2027 GENERAL RATE CASE
EXHIBIT (PG&E-4)
ELECTRIC DISTRIBUTION

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 1

ELECTRIC DISTRIBUTION POLICY AND INTRODUCTION

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ELECTRIC DISTRIBUTION POLICY AND INTRODUCTION

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 1
ELECTRIC DISTRIBUTION POLICY AND INTRODUCTION

A. Introduction

This chapter introduces Pacific Gas and Electric Company's (PG&E) Electric Distribution exhibit in PG&E's 2027 General Rate Case (GRC). The teams supporting the Electric Distribution exhibit are responsible for safely and reliably delivering electricity to PG&E's customers over a large and diverse service area through efficient and cost-effective planning, engineering, constructing, maintaining, and restoring of electric distribution assets.

Electric Distribution teams are focused on achieving the core mission to deliver affordable and clean energy safely and reliably to our customers every single day, while building the energy network of tomorrow, and meeting the challenge of climate change by integrating renewable and clean energy technologies. In addition, we are committed to improving the customer experience by delivering on our commitments. Electric Distribution exhibit's expense and capital forecasts represent a risk-informed portfolio that puts safety first while delivering on customer commitments and supporting California's clean energy goals.

B. Key Developments Since 2023 GRC

Since the 2023 GRC we have continued to focus on reducing wildfire risk, adapting to meet California's energization needs, and pursuing operational excellence. This section highlights some of the progress we have made in these areas since the 2023 GRC.

1. Wildfire Risk Reduction

In 2021, we announced a multiyear infrastructure safety program to underground powerlines in high wildfire-risk areas. Since launching the program, we have constructed and energized 875 miles of underground powerlines,[1] and we are on track to complete over 1,500 total miles of

[1] Underground mileage does not include work completed prior to 2021. See Exhibit (PG&E-4), Ch. 4, Section B.1 for mileage completed since 2019.

undergrounding through 2026 in our highest areas of wildfire risk.[2] In 2024 alone, we completed 258 miles of underground system hardening to support wildfire mitigation efforts. Our undergrounding efforts are making our system safer and more resilient, positioning us to better serve our customers and respond to our state's evolving climate challenges.

In addition to undergrounding, we have implemented an integrated strategy to manage and reduce ignition risk through a suite of comprehensive monitoring and data collection programs designed to provide insight into changing environmental hazards around our assets including wildfire cameras, weather stations, and asset inspections. These programs provide continuous monitoring capability that we use to decide which mitigations to deploy, and where and when to deploy them, as certain situations arise. To date, PG&E has installed 635 high-definition cameras and 1,585 weather stations to achieve visual coverage of over 90 percent of the Tier 2 and Tier 3 areas of the California Public Utilities Commission's (CPUC) High Fire Threat District (HFTD) map in PG&E's service territory.

Our strategy includes operational mitigations—like Down Conductor Detection (DCD) and Enhanced Powerline Safety Settings (EPSS)—that help automatically de-energize within one-tenth of a second or faster if a hazard makes contact with an EPSS-enabled line. The EPSS Program resulted in fewer CPUC-reportable ignitions and a reduction in acres impacted by wildfire. In 2024, we surpassed our Wildfire Mitigation Plan commitment to install DCD technology on 400 distribution protection devices, with the successful installation of approximately 700 relays or controller devices. Our EPSS protection prevented 629 potential wildfire ignitions or wildfire mitigation outages through the end of 2024. These prevented disruptions include outages occurring due to equipment failure, vegetation contact, animal contact, or third-party contact.

Through our EPSS program we are seeing reduced ignitions and making progress on reducing customer interruptions following EPSS enablement. In 2024, we reduced the Customer Average Interruption

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[2] Forecast of 1,500 miles through 2026 includes undergrounding for Butte Fire Rebuild and Community Rebuild.

Duration Index (CAIDI) and Customers Experiencing a Sustained Outage (CESO) for customers served by EPSS-capable lines as compared to data from the prior two-year average. Through the end of 2024, the average CAIDI was 150 minutes—a 17 percent reduction from the prior two-year average.

We will continue to conduct analysis on the reliability impacts when EPSS is enabled, as well as deploy the actions that we have available to reduce customer impact following EPSS enablement, including: (1) ground and aerial patrols and investigations; (2) enhancing our segmentation strategy; and (3) installing fault indicators.

2. Meeting California's Energization Needs

The Powering Up Californians Act[3] was signed into law in 2023 to enhance grid connections. The bill determines that in order to meet decarbonization goals and federal, state, regional, and local air quality and decarbonization standards, plans, and regulations, that the state's electrical distribution systems must be substantially upgraded, new customers must promptly connect to the electrical distribution system, and existing customers must have their service level promptly upgraded. The legislature directed the Commission to determine reasonable average and maximum energization time periods,[4] which the Commission adopted in Decision 24-09-020.

To improve PG&E's energization timelines, we worked with our customers on energization application process improvements. In 2024, PG&E partnered with the California Building Industry Association (CBIA) and other stakeholders in a workshop geared toward builders in PG&E's North Valley and Sierra and Central Valley regions. The goals of this workshop included helping customers better understand how to apply for a new-business connection; providing tips on how to quickly move projects from application to completion; and improving working relationships between builders and PG&E.

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3 Public Utilities (Pub. Util.) Code §§ 930-939.5.

4 Pub. Util. Code § 934(a)(1).

In conjunction with these process improvements, deployment of additional funding authorized in Decision 24-07-008 in July of 2024 resulted in a recent company record number of completed new business connections. PG&E completed 13,640 new business connections in 2024, including 1,624 new business connections in October alone. The year-end total was a significant increase from prior years, as new business connections were up nearly 30 percent from 2023, when PG&E completed 9,580 new business connections, and up nearly 40 percent compared to 8,490 new business connections in 2022.

It is critical that we continue to focus every day on accelerating our new business customers' connections to the electric grid. We are already beginning to see that our efforts in the areas above are reducing our project design backlog, which went from six-months in 2023 to less than a month by the end of 2024. Our Lean operating model and production system are the fundamentals that have allowed us to expedite service delivery.

3. Achieving Operational Excellence

In December of 2024, PG&E's electric operations and the Electric Asset Excellence (EAE) team achieved ISO 55001 recertification. Meeting ISO 55001 standards means that PG&E's electric asset management system meets the required level of resilience to dynamic risk conditions, resulting in a safer system for the hometowns we serve. Recertification also meets the Wildfire OII Settlement Agreement's requirement.[5]

As part of the preparation for recertification, the EAE team led the planning, preparation, and execution of the two-week recertification process with the auditor team, Lloyds Register Quality Assurance (LRQA). They also hosted office and field visits with coworkers and collaborated with teams across departments.

As LRQA noted in its final report, the Electric team faced many challenges over the past few years, including catastrophic wildfires. Despite these challenges, they worked diligently to improve the processes,

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[5] D.20-05-019, Appendix A, Settlement Agreement Between Pacific Gas and Electric Company, The Safety and Enforcement Division of the California Public Utilities Commission, Coalition of California Utility Employees, and the Office of the Safety Advocate Resolving Order Instituting, Investigation I.19-06-015, pp. 7-8.

procedures and systems that comprise our electric asset management system.

Since 2021, the team has closed out minor non-conformances and numerous LRQA scopes for improvement. Looking ahead, the team continues to act on more opportunities for improvement, including:

- Raising the visibility of the annual work plan to field coworkers for scheduling;
- Providing effective communication and verifying design changes in Substation Engineering; and
- Clearing the backlog of aged emergency orders.

The Electric team will use this information to guide future planning and strengthening of PG&E's electric asset management system across the service territory.

C. Areas of Focus in the 2027 GRC

Californians are in the midst of a significant shift in the state's energy landscape. Climate-driven risks to our system are evolving; customer demand to power people's homes and businesses is accelerating; and decarbonization efforts critical to meet the state's clean energy goals are progressing. With all of this change, it is imperative that PG&E's 2027 GRC policy reflect the need to drive transformation that will become the foundation for California's sustainable and prosperous future. PG&E must architect an electric system that is optimized to customer and system needs, fully decarbonized, and resilient to climate change, while delivering affordable energy and excellent customer experiences every day. Our path to achieving these results is guided by our 10-year True North Strategy. As described in Exhibit 2, Chapter 2, our True North Strategy is oriented around three core components to deliver our company purpose: Energy Systems, Customers, and Foundational Capabilities.

1. Safe and Reliable Energy Systems

In order to provide a level of service that our customers expect and deserve, we will continue to invest in the safety and reliability of our electric system while considering affordability. We will design our systems to be more resilient and flexible and achieve decarbonization goals.

Our 2027 GRC forecast includes several wildfire mitigation programs that increase the safety and resiliency of our electric system. PG&E will continue to invest in overhead and underground hardening and Remote Grid programs[6] which provide infrastructure upgrades to reduce significant wildfire risk and the reliance on operational controls that impact customer reliability. PG&E will continue to refine to wildfire mitigation operational programs like PSPS and EPSS that proactively mitigate the risk of wildfire, and leverage Customer Battery Programs to mitigate the impact of outages, especially for vulnerable customers.[7]

In addition, investments in our 4kV system conversion[8] will enable increased customer load. The new paradigm of the distribution planning and execution process must become more proactive by anticipating new loads and being prepared to serve them without lengthy distribution upgrades. Our existing 4kV system is unable to meet growing demands. Without conversion to higher voltages, existing 4kV areas will remain islands where customer growth and expansion are severely limited and where load growth will require extension of nearby, higher-voltage circuits, one customer at a time.

Work to reduce our maintenance tag backlog[9] continues to be front-and-center in our 2027 GRC, in order to prevent in-service failure and comply with the rules set forth in General Orders 95 and 165. We are planning to close all past due maintenance work in High Fire Threat Districts (HFTD) and High Fire Risk Areas (HFRA) by 2029, which will require a significant increase in pole replacements between 2027 and 2029. This proposal means that we will continue to have E and F tags open longer than

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6 See Exhibit (PG&E-4), Ch. 7.

7 See Exhibit (PG&E-4), Ch. 6.

8 See Exhibit (PG&E-4), Ch. 9.

9 Tag backlog is discussed further in Exhibit (PG&E-4), Ch. 15, and is defined in Section F.2 of that chapter.

GO 95, Rule 18 requirements in our non-HFTD past 2030.[10] PG&E will monitor and manage the risk associated with the open tags using aerial and ground asset inspections and patrol, vegetation management inspection, Down Conductor Detection (DCD), pole clearing, Enhanced Powerline Safety Settings (EPSS), and Public Safety Power Shutoffs (PSPS).

2. Meeting Customer Needs

Our customers are at the center of everything that we do. We will take action to support customer affordability and meet our customer's growing demands for energization.

Adequate funding to meet New Business customer demand is essential for PG&E to be able to fulfill its statutory obligation to serve customers, avoid customer energization backlog, and meet energization timelines. We must serve all of our customers, regardless of whether the GRC funding forecast aligns with the volume of customer requests that ultimately materialize. For this reason, we are requesting a two-way balancing account for new business capital activities to align funding with customer demand.[11] A balancing account will ensure unspent funds are returned to customers, and needed funds are available for PG&E to complete prompt energizations consistent with state law the Commission's average and maximum energization timelines.

Intertwined with our customers' needs are California's ambitious transportation electrification goals. California has introduced key legislation and executive orders which have been instrumental in addressing GHG emissions from the transportation sector,[12] and have helped lay the

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10 On September 26, 2023, PG&E submitted a letter to the CPUC requesting that SED stay application of the corrective action timelines in General Order (GO) 95, Rule 18 for Level 2 and Level 3 notifications while stakeholders evaluate GO 95 for potential updates and PG&E works down the distribution maintenance tag backlog as described in the 2023-2025 WMP.

11 See Exhibit (PG&E-4), Ch. 10, Section G.1.

12 CPUC Transportation Electrification, available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/transportation-electrification (accessed April 1, 2025).

groundwork for expanding electric vehicle (EV) infrastructure.[13] These legislative measures and executive directives underscore California's commitment to transportation electrification, and PG&E has and will continue to play a critical role in delivering the infrastructure to enable transportation electrification. Our 2027 GRC includes a forecast for New Business Plug-In Electric Vehicles that is based on historical EV adoption and considers actual deployment rates, in addition to the need to support the anticipated number of EVs in 2030 as part of the CEC's Electric Vehicle Charging Infrastructure Assessment. For additional detail on how electrification policy is driving demand and the associated benefits to customers, see prepared testimony in Exhibit (PG&E-4), Chapter 10, Section B.

3. Enhanced Foundational Capabilities

PG&E will continue to grow our foundational capabilities throughout the company to enable us to do our work more safely and efficiently.

One of the foundational capabilities that we will be pursuing throughout the 2027 GRC timeframe is our Integrated Grid Planning (IGP) process, described in greater detail in Exhibit 4, Chapter 2 testimony. IGP is a data-driven approach to planning that seeks to develop stable, multi-year investment plans that solve multiple needs and balance outcomes across multiple priority objectives. For example, the IGP process is producing plans that will help us bundle distribution pole replacements with non-pole maintenance tags on the same circuit segment to gain efficiencies and minimize customer impacts, as described further in Chapter 15.

Additional capabilities like our Advanced Distribution Applications will enable a diverse array of operational capabilities built on the foundational platform provided by the Advanced Distribution Management System, including operational capabilities that support CPUC goals of Distributed Energy Resources (DER) integration, affordability, reliability, and safety.[14]

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13 See the Clean Energy and Pollution Reduction Act of 2015 (SB 350), the Electric Vehicle Charging Infrastructure bills (AB 1082 and AB 1083), and Governor's Executive Order N-79-20 (Sept. 23, 2020).

14 See Exhibit (PG&E-4), Ch. 22.

The Distributed Energy Resource Management System will provide a foundational platform for managing DERs at scale on the distribution grid, including constraint management for interconnection, DER dispatch for distribution capacity project deferral, and DER program management for demand response and managed EV charging.

These programs support PG&E's objective of providing secure, reliable, and resilient electricity that enables continued gains for clean energy technology and California's economy in a way that gives customers value, flexibility, and choice in how they use energy.

D. Overview of the Electric Distribution Exhibit

As described above, Electric Distribution's 2027 GRC forecast contains expenditures for various programs that reduce wildfire risk, deliver on customer commitments, support California's clean energy goals, improve safety, and pursue operational excellence. The Electric Distribution Exhibit is organized as follows:

TABLE 1-1
ELECTRIC DISTRIBUTION EXHIBIT STRUCTURE

Line No.	Chapter No.	Chapter Title
1	1	Electric Distribution Policy and Introduction
2	2	Electric Distribution Forecast Summary and Investment Planning
3	3	Electric Distribution Risk Management
4	4	Wildfire Mitigation Summary and Strategy Support
5	5	Wildfire Situational Awareness and Forecasting
6	6	Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs)
7	7	Wildfire System Hardening
8	8	Vegetation Management
9	9	Electric Distribution Capacity, Engineering, and Planning
10	10	New Business and Work at the Request of Others
11	11	Electric Emergency Recovery
12	12	Distribution Systems Operations
13	13	Field Metering
14	14	Distribution Inspections

TABLE 1-1
ELECTRIC DISTRIBUTION EXHIBIT STRUCTURE
(CONTINUED)

Line No.	Chapter No.	Chapter Title
15	15	Overhead Maintenance and Poles
16	16	Underground Maintenance and Infrastructure Replacement
17	17	Overhead Infrastructure Replacement and Reliability
18	18	Substation Asset Management
19	19	Distribution System Automation and Protection
20	20	Electric Distribution Mapping and Data Management
21	21	Electric Distribution and Wildfire Mitigation Information Technology
22	22	Grid Modernization and Grid Technology
23	23	Electric Distribution Support Activities

Details of the forecast and changes in the exhibit organization from the 2023 GRC are provided in Chapter 2.

E. Conclusion

Since the 2023 GRC, PG&E has implemented programs to reduce wildfire risk, meet California's energization needs, and achieve operational excellence all while striving to serve customers safely and reliably. The forecasts in this exhibit will enable Electric Distribution to balance addressing our top safety risks, maintain and build safe and reliable energy system, meet customer expectations, and continue to develop our foundational capabilities.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ELECTRIC DISTRIBUTION FORECAST SUMMARY AND INVESTMENT PLANNING

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ELECTRIC DISTRIBUTION FORECAST SUMMARY AND INVESTMENT PLANNING

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PACIFIC GAS AND ELECTRIC COMPANY
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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ELECTRIC DISTRIBUTION FORECAST SUMMARY AND INVESTMENT PLANNING

A. Introduction and Summary

In this chapter, Pacific Gas and Electric Company (PG&E or the Company) describes the multi-year planning process used to develop the operation and maintenance (O&M) expense and capital expenditure forecasts for the Electric Distribution work presented in the 2027 GRC.

This chapter discusses the following: (1) the Electric Distribution forecast; (2) Electric Distribution's funding prioritization and cost forecasting approach; (3) the relationship of the Electric Distribution GRC forecast with other regulatory proceedings; (4) compliance with the 2023 GRC Settlement Agreement Principles for Deferred Work and with Public Utilities Code Section 935's requirement to address staffing levels; and (5) a summary of the forecast by GRC chapter and program area. Key changes in the presentation of the forecast compared to the 2023 General Rate Case (GRC) are provided in Attachment A to this chapter.

B. Overview of Forecast

PG&E's True North Strategy outlines our goals for our electric energy system. Our goal is to have an electric system that is resilient to climate change, decarbonized, optimized to local and system needs, and positioned to unleash the full potential of electric vehicles across our service territory. Exhibit 4 presents the Electric Distribution programs necessary to achieve these goals over the 2027 GRC and beyond in a risk-prioritized manner.

PG&E will continue to prioritize climate resiliency through permanent wildfire risk reduction with its system hardening plan to underground or overhead harden distribution infrastructure or deploy remote grids in High Fire Threat Districts (HFTD) when practical. In addition, the maintenance tag backlog in HFTDs will be completed by 2029, and work will be optimized using the plan to bundle work for efficient execution. Successful wildfire mitigation tools such as Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS) will continue, and new technologies such as Down Conductor Detection (DCD) will

continue to be introduced to achieve our stand that catastrophic wildfires shall stop. Lastly, PG&E continues to evolve its Vegetation Management practices, enhancing risk-informed planning to develop and execute on a portfolio of programs to focus on reducing wildfire risk in our HFTD and High Fire Risk Area (HFRA) and continued regulatory compliance.

PG&E believes there are targeted opportunities during the 2027 GRC period to deploy resources locally and improve our customer experience. This includes customer battery storage programs for customers in HFTDs who are experiencing PSPS and EPSS outages, as well as capacity bridging solutions to energize customers located on distribution circuits that require long-lead time upgrades. Additionally, targeted reliability investments are planned to improve customer service outside of EPSS and PSPS areas.

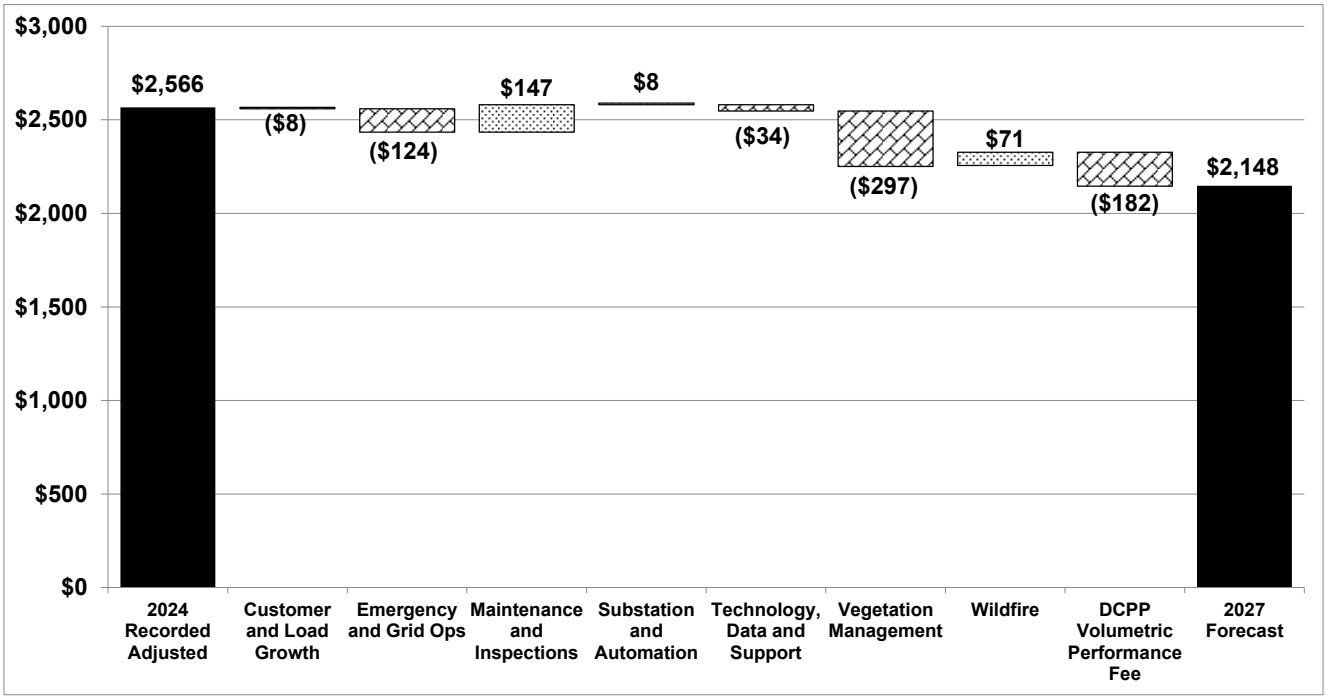
Lastly, PG&E's proposed investments in distribution capacity and new business work will support California's decarbonization goals and are a significant driver of Electric Distribution's overall forecast. PG&E forecasts a 4.5 times increase in non-residential electric vehicle (Rule 15/16 and Rule 29) demand, and a 2.3 times increase in residential electric vehicle demand from 2024 to 2027 alone. New business and capacity investment will be required to meet this demand, including converting PG&E's legacy 4kV systems to be able to support this electric vehicle growth as well as building electrification.

Figures 2-1 and 2-2 below summarize the Exhibit 4 forecast by capital, expense, and program area. Each chapter of this exhibit includes detailed forecast assumptions and corresponding outcomes to be achieved during this rate case period and beyond.

1. Expense Forecast

PG&E's Electric Distribution 2027 expense forecast is a reduction from 2024 recorded amounts. Figure 2-1 shows the 2024 recorded and 2025 to 2027 forecast expenses by program area.

FIGURE 2-1
EXPENSE FORECAST BY PROGRAM AREA (2024-2027)
(MILLIONS OF NOMINAL DOLLARS)



Note: The values reflected in this table may vary from the initial Results of Operations (RO) Model provided with PG&E's GRC filing due to timing differences. The RO Model will be updated to incorporate these errata in a future submission.

The largest changes from 2024 in the expense forecasts are:

- Reduction in Vegetation Management (VM) forecast driven by operational efficiencies, such as incorporating VM activities into Routine and/or Hazard patrols, tree removal assumptions, and the impact of PG&E's undergrounding activities;
- Increase in Maintenance and Inspections to reduce the maintenance tag backlog in both the HFTD and non-HFTD;
- Reduction in Emergency & Grid Operations forecast primarily driven by 2024 recorded Major Emergency costs being higher than average; and
- Increase in Wildfire mitigation forecast primarily driven by PSPS events (which is based on a 5-year average) due to 2024 recorded PSPS costs being lower than average.

Furthermore, as described in detail in Exhibit (PG&E-2), Chapter 2, PG&E intends to utilize Volumetric Performance Fee (VPF) revenues earned from the extended operations of Diablo Canyon Power Plant (DCPP)

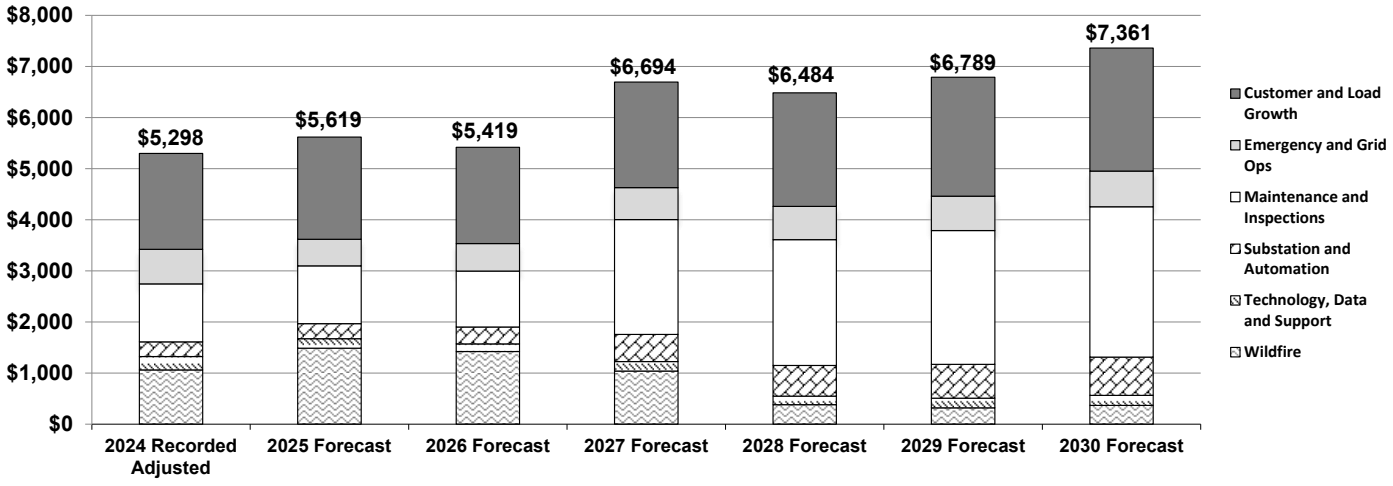
to cover the costs of certain programs that qualify for VPF funding per the requirements of Pub. Util. Code Section 712.8(s). This Exhibit forecasts the work activities needed to run the business. Acknowledging that a portion of these work activities will qualify for recovery via VPF revenues, we have reduced the expense forecast by approximately $182 million annually 2027-2029 (and $71.4 million in 2030), assuming that these eligible costs will be recoverable through the VPF. This is our current best estimate of the cost of the work activities included in our 2027 expense forecast for which we will seek recovery through the VPF mechanism 2027-2030.

PG&E also forecasts the portion of O&M expenses for electric assets that are at transmission voltages but are included in the GRC due to the associated assets being under CPUC jurisdiction. This forecast is included in Exhibit (PG&E-10), Chapter 4.

2. Capital Forecast

Figure 2-2 shows the 2024 recorded and 2025 to 2030 forecast capital expenditures for Electric Distribution by program area.

FIGURE 2-2
CAPITAL FORECAST BY PROGRAM AREA (2024-2030)
(MILLIONS OF NOMINAL DOLLARS)



Note: The values reflected in this table may vary from the initial Results of Operations (RO) Model provided with PG&E's GRC filing due to timing differences. The RO Model will be updated to incorporate these errata in a future submission.

PG&E forecasts increased capital spending 2025-2030 relative to 2024 recorded. The capital spending will support PG&E's activities to continue modernizing the grid for wildfire mitigation and resiliency; safety and reliability; and electrification and decarbonization.

The largest changes in the capital forecasts are:

- Reduction in Technology and Data Support driven by the completion of the Advanced Distribution Management System (ADMS) and moving to deployment of applications to support ADMS;
- Reduction in Emergency & Grid Operations as a result of 2024 recorded Major Emergency costs being higher than average;
- Increase in Maintenance and Inspections driven by work to reduce the maintenance tag backlog in both the HFTD and non-HFTD;
- Increase in Customer and Load Growth forecast driven by capacity demand tied to new business customer connections and electric vehicles; and;
- Increase in Substation and Automation driven by failure rates driving increased substation emergency repairs and the purchase of capital emergency materials.

3. Efficiency and Affordability

PG&E plans to improve affordability through a variety of work efficiency initiatives. Targeted improvements are built into the forecasts for chapters that have in-flight or identified initiatives. The affordability benefits are shown through absorption of unit cost escalation. Examples of the initiatives driving efficiency improvements are:

- Production System: Using the Lean Operating System to improve work execution efficiencies;
- Integrated Grid Planning (IGP): Produces plans to solve all needs identified for a given circuit or substation to execute work in a cost-efficient manner. This is described in Section C.2; and
- Work Bundling: Bundling Electric Corrective (EC) notification tags in an isolation zone to maximize the number of notifications completed within a single outage or planned day of work.

Workplan efficiencies and affordability initiatives will be monitored and tracked. Identifying efficiencies is fundamental to increasing affordability for customers and increasing throughput.

These efficiencies are built into some forecasts where applicable while escalation is applied to forecasts where additional efficiencies have not been identified. Table 2-1 highlights where efficiencies are built into that chapters' main program forecasts, highlighting results of PG&E's work to lower costs for customers.

TABLE 2-1
EFFICIENCIES BUILT INTO FORECASTS

Line No	Chapter	Type of Efficiency
1	Ch 6 Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs)	Production System
2	Ch 7 Wildfire System Hardening	Production System
3	Ch 8 Vegetation Management	Production System
4	Ch 9 Electric Distribution Capacity, Engineering	IGP & Work Bundling
5	Ch 14 Distribution Inspections	Production System
6	Ch 15 OH Maintenance and Poles	Work Bundling
7	Ch 16 UG Maintenance and Infrastructure Replacement	Work Bundling
8	Ch 17 Overhead Infrastructure Replacement and Reliability	IGP
9	Ch 18 Substation Asset Management	IGP
10	Ch 19 Distribution System Automation and Protection	Production System
11	Ch 23 Electric Distribution Support Activities	Production System

The remaining chapters not listed in the table above have escalation applied to the main programs in their forecasts. See descriptions in those chapters for more information on what escalation was applied.

4. Special Attrition Mechanism Programs

PG&E's forecast includes programs with targeted spend trajectory. The targeted treatments are necessary to achieve the strategies, commitments, and regulatory requirements that are presented in the chapters identified below.

Table 2-2 below lists the Electric Distribution programs in Exhibit 4 for which PG&E is requesting targeted treatment:

TABLE 2-2
ELECTRIC DISTRIBUTION SPECIFIC POST TEST-YEAR ATTRITION PROGRAMS

Line No	Chapter	Program	Expense/Capital
1	6	Customer Battery Programs	Expense and Capital
2	7	Wildfire System Hardening – Undergrounding	Capital
3	8	Vegetation Management	Expense
4	9	Distribution Capacity Program	Capital
5	15	Electric Distribution Overhead Maintenance	Capital

Please refer to the chapters above for more information on the specific Post Teat-Year (PTY) attrition applied, and refer to Exhibit (PG&E-11), Chapters 2 and 3 for a discussion on Post Test-Year Ratemaking (PTYR).

5. Shift to Capitalize Work

PG&E's forecast reflects capitalization policy changes resulting in some previously expensed work forecast as capital in this GRC. These changes are consistent with FERC accounting rules and are aligned with the practices of other California utilities.[1] Shifting costs from expense to capital for eligible assets addresses intergenerational equity because it aligns the cost recovery to the customers that benefit from those assets. Capitalization also makes bills more affordable for customers in the near term. This is because assets classified as expense are collected fully from customers as the costs are incurred, whereas assets classified as capital expenditures are recovered over the life of the asset, which can be 20+ years.

Capitalization changes to the Electric Distribution forecast include:

- Intrusive Pole Inspections: The Intrusive Pole Inspections program (also called Pole Test and Treat) was previously 100 percent expense. Starting in 2027, pole treatment will be capitalized and so the 2027 forecast is allocated to expense and capital based on FERC accounting rules. See Chapter 15 in this exhibit for more program information;
- Pole Reinforcement: Installation of steel trusses to reinforce wood poles experiencing groundline decay or damage was previously 100 percent

[1] See Exhibit (PG&E-10), Ch. 7 for information on FERC accounting rules.

expense. This work is recorded and forecast as capital beginning in 2024. This program is also described in Chapter 15; and

- IT Projects: The forecasts in Chapter 21 for Electric Distribution and Wildfire Mitigation Technology reflect capitalization policy changes which result in forecasts for work that was previously expense now being forecast as capital. See Chapter 21 and Exhibit (PG&E-7), Chapter 7 for more information.

A change that is not included in the Electric Distribution forecast but may occur in the 2027 GRC period is the shift from expense to capital for some of the IT work forecast in Chapter 8, Vegetation Management. This change would be consistent with IT software capitalization policies, however the current GRC forecast reflects these costs as expense.

6. Balancing and Memorandum Accounts

Table 2-3 below summarizes the proposals presented in this Exhibit 4 for Balancing and Memorandum Accounts supporting Electric Distribution. See the chapters listed for the specific account requests. PG&E is generally proposing that balancing account mechanisms approved in the 2023 GRC continue with limited modifications and is proposing a new balancing account for New Business capital. Additionally, PG&E is proposing closing certain memorandum accounts.

TABLE 2-3
BALANCING AND MEMORANDUM ACCOUNTS

Line No.	Account Name	Action	Chapter
1	Create New Account		
2	New Business Balancing Account (NBBA)	New	10
3	Retain Accounts Without Modifications		
4	Wildfire Mitigation Balancing Account (WMBA)	Retain	4
5	Rule 20 Balancing Account (RBA)	Retain	10
6	Major Emergency Balancing Account (MEBA)	Retain	11
7	Overhead/Underground Maintenance Balancing Account (OUMBA)	Retain	15,16
8	Critical Operating Equipment Cable Replacement Balancing Account (COECRBA)	Retain	16
9	Microgrid Balancing Account (MGBA)	Retain	22
10	Distribution Resources Plan Tools Memorandum Account (DRPTMA)	Retain	22
11	Distributed Energy Resources Distribution Deferral Account (DERDDA)	Retain	22
12	Modify Existing Accounts		
13	Vegetation Management Balancing Account (VMBA)	Modify	8
14	Discontinue Accounts		
15	Electric Capacity and New Business Interim Memorandum Account (ECNBIMA)	Close	9,10
16	Microgrid Memorandum Account (MGMA)	Close	6
17	AB 841 Memorandum Account (AB841MA)	Close	10

C. Electric Distribution Planning and Prioritization

PG&E uses an annual enterprise-wide strategic planning and budgeting process called Business Plan Deployment (BPD), which guides the timing, review, and confirmation of Electric Distribution's work portfolio. BPD covers a multi-year period to achieve PG&E's True North Strategy (TNS) with full visibility, regulatory alignment, and executability within available resources. BPD is a systematic approach to PG&E's planning which focuses on: (1) identifying top compliance, enterprise, and operational risks, (2) developing a 6-year operating plan, including specific outcomes and strategies, and (3) establishing PG&E's execution and financial plan.

For Electric Distribution, Electric Investment Planning is the specific function and process used to develop the long-term plan and portfolio of work. Before work can be prioritized, investments are identified to be considered during the annual BPD Cycle. The identification of work includes work that is

in-flight, newly identified projects, volume of units, and placeholders for emergent work. Once the full list of work is identified, the investment planning team will partner with Asset Strategy and Operations to prioritize and sequence the investments within financial and resource constraints. To help drive the year-over-year sequencing of work, PG&E uses an enterprise-wide risk methodology called Risk Based Prioritization Planning Framework (RBPPF), as well as input from Integrated Grid Planning (IGP) to ensure short-term investment aligns to long-term outcomes on asset health and reliability.

1. Risk Based Prioritization Planning Framework

PG&E's RBPPF establishes a consistent and comparable approach to categorizing and prioritizing proposed investments across PG&E to achieve the Company's commitments to People, Planet, and Prosperity. RBPPF is a scoring and tiering methodology focused on five categories: (1) risk reduction, (2) compliance, (3) capacity, (4) reliability, and (5) other TNS/customer objectives. This tiering methodology scores investments 1 to 5 in each category, with 5 indicating work with greatest urgency or highest impact. Below is a summary from the RBPPF standard for what PG&E classifies as Tier 5 and considered a priority:

- Risk Reduction: Risk mitigation program with CBR of 1 or greater and program is needed to achieve baseline risk reduction.
- Compliance: Federal or state required work or external commitment with completion date in current year.
- Capacity: Known or projected delay in provision of new service or expansion of existing service to serve load/throughput growth impacting multiple critical locations or critical customers for greater than 1 year; or results in utility owned generation nameplate capacity of greater than 100 MW delayed for greater than 1 year; or work adds IT capacity/scalability to address known or anticipated deficiency related to one or more mission critical processes, systems, or locations.
- Reliability: Known or projected threat to continuity of existing electric service: is widespread or frequent and impacts multiple critical locations or critical customers; or is greater than 100 days or 100,000 customers; or results in high probability (>80 percent) of utility owned generation loss with replacement power cost greater than proposed cost of work, or

results in high probability risk of generation loss during peak summer demand period; or work addresses known or projected deficiency in the health of IT assets that support one or more mission critical processes, systems, or locations.

- Other TNS Objectives: Highest impact and highest urgency investment driving one or more TNS goals (e.g., carbon emission reductions, megawatts of available capacity from load management, customer satisfaction), with limited opportunity to defer work to future period(s).

For Electric Distribution specifically, RBPPF highlights the priority of WMP commitments and risk reduction activities, in-year compliance requirements, emergency, and a growing customer base and load forecasts.

Electric Distribution continuously monitors risk and adjust its plans using multiple data sources in addition to the RBPPF. Cost Benefit Ratios (CBR) are an estimate of risk that supplement the RBPPF. Electric Distribution also continuously evaluates priorities, considers new data, and incorporates regulatory direction, including feedback on its Wildfire Mitigation Plan (WMP) from OEIS (Office of Energy Infrastructure Safety) and intervening parties. These items set commitments and requirements which influence RBPPF scoring and/or establish minimum investment levels. The forecasts in this exhibit are a result of that process and represent the current risk-informed plan.

In addition, climate change continues to impact our assets and operations. Climate change is linked to increasing wildfire risks, more extreme storm conditions, more frequent and intense heat waves, and increased coastal and inland flooding. Given these substantial climate-driven impacts, we have started to identify investments in our 2027 GRC that intentionally enhance energy system reliability or recoverability relative to projected climate-driven natural hazards. At present, a climate-informed investment considers whether an investment is primarily motivated as a response to natural hazard conditions impacted by climate change. Furthermore, a climate-informed investment must also meet one of the following conditions: be a wildfire investment; directly address a vulnerability identified in the 2024 Climate Adaptation and Vulnerability

Assessment (CAVA);[2] or be supported by a design standard that has been updated using climate projection data about future operating conditions or other climate-informed analysis. Investments that only enhance baseline operational capabilities in response to current natural hazard conditions and do not explicitly include the consideration of future environmental conditions do not qualify as climate-informed investments. Please see Exhibit (PG&E-2), Chapter 1 for more information.

2. Integrated Grid Planning (IGP)

Integrated Grid Planning (IGP) is a data-driven approach to planning that seeks to develop stable, multi-year investment plans that solve multiple needs and balance outcomes across multiple priority objectives. These plans are developed by holistically reviewing system needs, assigning solutions to resolve those needs, and then prioritizing investment scenarios based on financial, resource, and execution constraints.

IGP produces plans based on all needs identified for a given circuit or substation. In doing so, IGP identifies the allocated capital, year of investment, and proposed solution details for each circuit or substation on the system (e.g., work on Circuit X in Year X that includes XX poles replaced, XX miles of OH conductor replaced, etc.). These plans are accompanied by the expected impact of the prescribed work on multiple priority objectives such as capacity, reliability, asset health, etc.

IGP is a multistep process to allow for a detailed asset level scope for the next 10 years and beyond. By consolidating system asset need data and scoping holistically by circuit or geographical regions, work can be bundled together and optimized to achieve the greatest risk buy-down of system need for every dollar spent. A significant reduction in the cost for work types occurs when volumes of work can be bundled together. The objectives of IGP are to:

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[2] PG&E submitted its first CAVA pursuant to Climate Change Adaptation Rulemaking (May 12, 2024) R.18-04-019. (See Exhibit (PG&E-2), Ch. 1 for more information). A key recommendation from this risk assessment was for PG&E to begin proactively planning for climate change by updating the design standards and further integrating climate projection information into internal planning processes.

- Design and implement a stable and actionable long-term strategic plan aligned with our goals and objectives;
- Optimize and scope planned work and executed it as a bundle by location (i.e., protective zone, circuit, or substation); and
- Transform execution and operations to achieve execution efficiencies by optimizing resources, permitting, materials, and shovel ready work.

D. Relationship to Other Proceedings

The following proceedings may impact PG&E's 2027 GRC:

1. SB 884 Electric Undergrounding Plan

In October 2022, Senate Bill (SB) 884 was introduced by the California legislature to expedite undergrounding of electric utilities distribution infrastructure. Under SB 884, large electric utilities can submit a 10-year Electric Undergrounding Plan (EUP) to OEIS, which will include timelines for completion, annual undergrounding mileage targets, and an evaluation of project costs and projected benefits (including risk reduction analysis). After the EUP is reviewed and approved by OEIS, PG&E will submit a copy of the EUP and an application requesting review and approval of the plan's costs to the CPUC. However, final OEIS EUP Guidelines were issued much later than expected, and have pushed back the feasible timing for PG&E to submit the EUP.[3] To address a potential funding gap, PG&E included one year of undergrounding forecast (2027) in this GRC. PG&E also requests a mechanism to extend undergrounding cost recovery if there are further EUP delays. For more information on the undergrounding program and the EUP, please see Chapter 7 of this exhibit.

2. Establish Energization Timelines OIR (R.24-01-018)

In September 2024, the Commission established average and maximum energization timelines as required by the Powering Up Californians Act.[4] In order to comply with these timelines, PG&E filed a motion to increase the annual cost caps for the Energization Capacity New Business Interim

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[3] PG&E intends to file its EUP in 2025 (at the earliest).

[4] SB 410 (2023-2024 Reg. Sess.) and Assembly Bill (AB) 50 (2023-2024 Reg. Sess.); see also D.24-09-020.

Memorandum Account (ECNBIMA)(SB 410 Motion).[5] The increased caps would provide additional funding for energization work, including components of new business (MWC 16), distribution capacity (MWCs 06 and 46), and energization-related Work at the Request of Others (MWC 10). At the time of preparing the 2027 GRC forecast, PG&E's SB 410 Motion was still pending. A critical assumption of PG&E's new business forecast is that all projects that were ready prior to 2027 and customers that have requested service prior to 2027 will be energized prior to 2027. In other words, this assumes there is no carryover work from prior years, where a customer application is complete, ready, and waiting beyond its requested date for service. To the extent the decision on the SB 410 Motion provides less interim funding than needed to complete the forecasted new business customer requests in 2025 and 2026, there is a risk that there will be carryover work to the 2027 GRC cycle. Authorization of a two-way balancing account in this GRC will resolve the risk of PG&E's new business cost forecast not capturing the potential carryover units, as PG&E's funding would be commensurate with actual customer demand. Please see Exhibit (PG&E-4), Chapter 10 for more information.

E. Compliance

1. Deferred Work Analysis

a. Balancing Electric Distribution's Portfolio of Work

In Section C, PG&E describes the Electric Distribution Investment Planning process which leads to an annual Electric Distribution budget that is approved by the executive leadership team before the budget year begins. Balancing the Electric Distribution portfolio includes allocating funding to the highest priority work, mandatory work, and new work through the processes described in Section C above. PG&E continuously uses the RBPPF to address emergent needs across the Electric Distribution portfolio.

PG&E's 2023 GRC presented forecasts for a portfolio of work which prioritized wildfire risk reduction, including significant investments in

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[5] See *Pacific Gas and Electric Company Motion to Revise 2025 and 2026 Energization Cost Caps*, (October 4, 2024) in R.24-01-018.

undergrounding, customer load growth, and maintenance and compliance. However, the Electric Distribution forecast in the 2023 GRC was constrained by targets established by the Plan of Reorganization when PG&E emerged from bankruptcy, and did not include all funding needed to address maintenance tag backlog and emergent customer connection demands. Additionally, in the 2023 GRC decision, the Commission significantly reduced PG&E's forecast in several areas, including undergrounding, maintenance tags and pole replacements, and escalation rates which affected all programs.[6]

TABLE 2-4
ELECTRIC DISTRIBUTION SPEND COMPARISON FOR 2023-2026
(MILLIONS OF NOMINAL DOLLARS)

Line No.	Description	2023-2024 Recorded Adjusted and 2025-2026 Forecast	2023 GRC (2023-2026 Imputed Adopted Values)	Decision 24-07-008 Energization 2024-2026 Imputed Adopted Values	Difference Over-Spend (Under-Spend)
1	Expense Total	$9,341	$9,196	–	$145
2	Capital Total	$21,024	$16,434	$2,263	$2,327

Table 2-4 includes the additional capital expenditures authorized for interim rate recovery for energization work in Decision 24-07-008, as described in Section D.2 above.

For expense, the primary reasons for the higher-than-imputed spending include: (1) increased volume and higher unit costs for overhead maintenance tags (MWC KA), (2) more routine and major emergency work than forecast (MWCs BH, IF), (3) additional vegetation management work to meet WMP commitments not included in PG&E's 2023 GRC forecast (MWC IG), and (4) increased costs for distribution inspections including a new aerial inspection program (MWC BF). These areas are partially offset by lower-than-adopted spending for: (1) Public Safety Power Shutoff events (MWC AB), (2) patrol response

[6] D.23-11-069, p. 800, Finding of Fact (FOF) 109; p. 868, Conclusion of Law (COL) 118; p. 868, COL 119; p. 871, COL 134; p. 915, Ordering Paragraph (OP) 56.

costs for Enhanced Power Safety Settings (MWC BH), and (3) operational support costs (MWC OS).

Electric Distribution 2023-2026 capital expenditures are forecast to be higher than imputed in numerous programs including: (1) new business customer connections (MWC 16) and work at the request of others (MWC 10); (2) distribution line and substation capacity work (MWCs 06, 46); (3) pole replacements (MWC 07); (4) overhead maintenance tags (MWC 2A); and (5) routine and major emergency work (MWCs 17, 95).

Higher spending for new business customer connections and distribution line and substation capacity work is aligned with additional funding provided by D.24-07-008.[7] In addition, PG&E is overspending in Plug-in Electric Vehicle (PEV) capital infrastructure work covered by Rule 29 PEV. This work includes distribution transformer, secondary, and service upgrade work to serve increased loads related to PEVs. The Commission authorized PG&E to establish a AB841 Memorandum Account (AB841MA) to track and record these costs until a Rule 29 PEV forecast was adopted in a future general rate case. The Commission did not adopt a forecast for this work in the 2023 GRC. Work at the Request of Others (WRO) is also forecast to spend over adopted amounts. This work involves relocating electric distribution and service facilities at the request of a government agency or other third party (e.g., private parties and developers). PG&E is required to perform this work under Rules 13, 15, and 16, and franchise agreements with local governments. WRO projects and associated costs can vary greatly depending on the scope of the customer request.

PG&E is incurring increased capital spending above GRC-authorized for pole replacement activities (MWC 07) for damaged or deteriorated poles. Pending pole maintenance tags identified during inspections must be resolved to address this safety and reliability issue.

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7 PG&E's forecast for 2025 and 2026 does not include costs associated with PG&E's pending motion to increase the energization cost caps in *Pacific Gas and Electric Company Motion to Revise 2025 and 2026 Energization Cost Caps*, (October 4, 2024) in R.24-01-018.

Pole replacement activities in high-fire threat districts (HFTDs) also meet commitments made in our wildfire mitigation plans (WMP).

Electric Distribution also anticipates overspending on overhead maintenance for the 2023-2026 period as we continue to resolve pending maintenance items identified during inspections. This work is needed to maintain safety and reliability, and comply with Commission General Orders. The Overhead Underground Maintenance Balancing Account (OUMBA), authorized in the 2023 GRC provides flexibility to account for variability in the amount of work needed to complete based on system inspections.

Finally, Electric Distribution is incurring costs above authorized for both Routine Emergency (MWC 17) and Major Emergency (MWC 95). Major Emergency is subject to the Major Emergency Balancing Account (MEBA). The MEBA is a two-way balancing account that authorizes spending above the GRC adopted forecast as necessary to respond to major emergencies not declared as catastrophic events. In 2024 alone, PG&E incurred both routine and major emergency response costs significantly higher than authorized. PG&E must complete this emergency work to restore service, and to maintain safety and reliability.

Despite PG&E's expense and capital spend exceeding the 2023 GRC imputed adopted amounts, PG&E forecasts deferred work in 13 specific work categories and 5 chapters including: (1) Distribution Inspections (Chapter 14); (2) Overhead Maintenance and Poles (Chapter 15); (3) Underground Maintenance and Infrastructure Replacement (Chapter 16); (4) Overhead Infrastructure Replacement and Reliability (Chapter 17); and (5) Substation Asset Management (Chapter 18). Funding for these programs was generally reprioritized in the following ways: (1) to alternative programs not forecast in the 2023 GRC (e.g., Aerial Inspections); (2) to higher priority work in other programs including Emergency Replacement (MWC 17), Capacity Improvements (MWC 06,46), and Pole Replacements (MWC 07); and lastly (3) to other critical work within the same Major Work Category (e.g., Substation Emergency Replacements). Other programs that do not forecast to complete the imputed units did not meet the criteria for

deferred work based on the analysis presented in the Deferred Work Analysis Summary workpaper,[8] for the reasons described in Section E.1.b. below including, but not limited to, discontinued work, demand-driven work, and work subject to balancing account treatment.

The portfolio prioritization process described in Section C above supported these shifts in spending from what was authorized in the 2023 GRC. The need to re-prioritize funding in the 2023 to 2026 timeframe has resulted in forecasts for some programs in years 2025 and 2026 to be lower than recorded amounts in 2024, as available funding is shifted to these higher priority areas. PG&E will use the annual planning process described above to re-allocate funds as needed in those years to ensure necessary work continues.

b. Analysis of "Deferred Work"

The 2023 GRC decision directs PG&E to continue to follow the directives in the 2020 GRC Deferred Work Settlement and to include testimony in this GRC on "deferred work" where the following criteria are met:

1) The work was requested and authorized based on representations that it was needed to provide safe and reliable service (Check 1);
2) PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work (Check 2); and
3) PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service (Check 3).

The results from the Electric Distribution review to determine if any work was deferred are summarized in the Deferred Work Analysis Summary workpaper.[9] Each witness reviewed the MAT codes that are included in their 2027 GRC chapter and answered each of the three questions listed above to determine if work meets the Deferred Work Settlement criteria. The three questions are shown as Check 1, Check 2, and Check 3 in the workpaper. For purposes of the deferred

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8 See Exhibit (PG&E-4), WP 2-19.

9 See Exhibit (PG&E-4), WP 2-19.

work analysis, Check 2 is divided into two Checks (2a and 2b). The answers to each Check are listed in Columns G through J by MAT. After answering the three deferred work questions, the witness provided the reason that work meets or does not meet the deferred work criteria in Column K.

To analyze whether "the work was requested and authorized based on representations that it was needed to provide safe and reliable service" (Check 1), a "Yes" is entered for the following work: (1) any MAT codes identified as safety, reliability, or maintenance (SRM)-related in the 2023 Risk Spending Accountability Report (RSAR);[10] and (2) any activities not captured in the 2023 RSAR under (1), but where some or all of the work was requested in the 2023 GRC based on representations that the work was "needed to provide safe and reliable service."

Next, to analyze whether "PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work" (Check 2), PG&E first evaluated whether units were imputed for the work based on the 2023 GRC decision. For GRC work, PG&E then compared 2023 and 2024 recorded units, and 2025 and 2026 forecasts to the units imputed for the period 2023-2026. Under PG&E's analysis, Check 2 applies where PG&E's 2023 and 2024 actuals and the 2025 and 2026 forecast indicate that the imputed units of work will not be completed by the end of 2026.

Finally, to analyze whether "PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service" (Check 3), PG&E reviewed its 2023 GRC testimony to establish whether it is again proposing the same work for safety and reliability in the 2027 GRC. The response to Check 3 is "No" for work meeting the following conditions:

- Discontinued Work: Discontinued work is no longer being represented as necessary for safe and reliable service. For example, TripSaver device installations that were imputed in

10 See PG&E's Amended 2023 Risk Spending Accountability Report (June 17,2024).

MAT 49T are not standard equipment and PG&E is no longer forecasting device installations. For that reason, work in this program is not considered deferred.

- Demand-Driven Work: Demand-driven work is conducted on an "as-needed" basis. The forecast for demand-driven work is generally based on a historic average of the recorded units of work. The actual number of units completed depends on the work that materializes during the rate case period, whether more units of work or fewer. For example, unitized electric meter-related work in Chapter 13, Field Metering, and Substation Corrective Maintenance in Chapter 18, Substation Asset Management is considered demand-driven.
- Subject to Balancing Account: If the work is subject to a balancing account, and the unspent funding is returned to rate payers, this is not considered deferred work. For example, wildfire camera installations in MAT WFC are recorded in the WMBA and Underground Cable Replacement in MAT 56C are recorded in the COECRBA. Based on the balancing account treatment of these programs, this work is not considered deferred.

For areas of work where the answer is "No" to one or more of the three checks, PG&E determined that the area of work did not qualify as "deferred work" as this term is used in the Deferred Work Settlement.

If the answer is "Yes" to all three checks, PG&E determined that the work qualified as "deferred work" as this term is used in Deferred Work Settlement.

Table 2-5 summarizes the deferred work identified by PG&E's analysis for Electric Distribution by program and chapter.

TABLE 2-5
LIST OF ELECTRIC DISTRIBUTION DEFERRED WORK PROGRAMS

Line No.	Program, Chapter and Witness	Reason for Deferred Work	Imputed/ Adopted Units from the 2023 GRC (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast
1	Underground Manhole Inspections – Expense (MAT BFF) Chapter 14 – Distribution Inspections Witness: Joanna Sturges	PG&E does not expect to complete 3,137 units of manhole/vault inspections out of the imputed 6,184 units. The program will be underspent by $318 thousand compared to imputed funding. <u>Reasons:</u> Reprioritization: PG&E reallocated funds for manhole inspections to other higher priority compliance work in MWC BF, including aerial inspections in MAT BF1. MAT BF1 is a new program that was not forecast in the 2023 GRC. Manhole inspections are still performed in accordance with GO165 compliance requirements.	Units: 6,184 Manholes/ Vaults inspected Cost: $2,040	Units: 3,047 Manholes/Vaults inspected Cost: $1,722

TABLE 2-5
LIST OF ELECTRIC DISTRIBUTION DEFERRED WORK PROGRAMS
(CONTINUED)

Line No.	Program, Chapter and Witness	Reason for Deferred Work	Imputed/ Adopted Units from the 2023 GRC (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast
2	Overhead Equipment Testing – Expense (MAT BFG) Chapter 14 – Distribution Inspections Witness: Joanna Sturges	PG&E does not expect to complete 25,318 units of equipment inspections out of the imputed 102,305 units. Program will be overspent by $558 thousand compared to imputed funding. <u>Reasons:</u> Unit costs for Overhead Equipment Tests were higher than anticipated in 2023 and 2024. In 2023 and 2024 PG&E completed all of the required equipment tests according to standard. 2025 and 2026 budget for this program is lower than 2023 and 2024, and accordingly PG&E is evaluating ways to complete all units to standard at a lower unit cost.	Units: 102,305 Equipment Inspections Cost: $10,683	Units: 76,987 Equipment Inspections Cost: $11,241

TABLE 2-5
LIST OF ELECTRIC DISTRIBUTION DEFERRED WORK PROGRAMS
(CONTINUED)

Line No.	Program, Chapter and Witness	Reason for Deferred Work	Imputed/ Adopted Units from the 2023 GRC (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast
3	Pole Test and Treat – Expense (MAT GAA) Chapter 15 – Overhead Maintenance and Poles Witness: Joanna Sturges	PG&E does not expect to complete 842,934 units of pole inspections out of the imputed 1,039,331 units. Program will be underspent by $44.3 million compared to imputed funding. <u>Reasons:</u> PG&E's execution strategy has changed from what was authorized in the 2023 GRC for Pole Test and Treat, with the program prioritizing Comprehensive Pole Inspections (CPIs) which help inform and prioritize EC notifications to determine if the work needs to be performed. CPIs can be more costly on a per unit basis than routine inspections because work can not be performed as efficiently as through routine inspections. As a result of this change in strategy, a portion of the inspections originally forecast for the 2023 GRC will need to be completed after 2026. The Pole Test and Treat program still maintains compliance with GO 165 requirements. PG&E reallocated funds for Pole Test and Treat inspections to other high priority inspection work such as Aerial Inspection in MAT BF1.	Units: 1,039,331 Inspections Cost: $86,456	Units: 196,397 Inspections Cost: $42,131

TABLE 2-5
LIST OF ELECTRIC DISTRIBUTION DEFERRED WORK PROGRAMS
(CONTINUED)

Line No.	Program, Chapter and Witness	Reason for Deferred Work	Imputed/ Adopted Units from the 2023 GRC (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast
4	Pole Analyze Loading – Expense (MAT GAC) Chapter 15 – Overhead Maintenance and Poles Witness: Joanna Sturges	PG&E does not expect to complete 555,154 units of pole loading analysis out of the imputed 800,000 units. Program will be underspent by $39.3 million compared to imputed funding. Reasons: PG&E's work in 2023 and 2024 in MAT GAC was focused on poles in HFTD locations. During that analysis, we identified a population of poles that required additional data to perform the analysis. In order to complete those higher priority HFTD units, we paused additional analysis and focused on performing more detailed calculations on the HFTD populations. We anticipate continuing to work on that population through 2026, at which point we will switch to prioritized non-HFTD analysis.	Units: 800,000 Cost: $90,607	Units: 244,846 Cost: $51,354
5	UG Cable Other Replacement – Capital (MAT 56A) Chapter 16 – Underground Maintenance and Infrastructure Replacement Witness: Connie Taylor	PG&E does not expect to complete 32 miles of cable replacement out of the imputed 70 miles. Program will be underspent by $78.6 million compared to imputed funding. Reasons: Reprioritization: PG&E is reprioritizing work in 56A to higher priority work in emergency replacements (MWC 17), capacity improvements (MWC 06,46), and pole replacements (MWC 07).	Units: 70 Circuit Miles Cost: $162,355	Units: 38 Circuit Miles Cost: $83,731

TABLE 2-5
LIST OF ELECTRIC DISTRIBUTION DEFERRED WORK PROGRAMS
(CONTINUED)

Line No.	Program, Chapter and Witness	Reason for Deferred Work	Imputed/ Adopted Units from the 2023 GRC (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast
6	Network Cable Replacement – Capital (MAT 56N) Chapter 16 –Underground Maintenance and Infrastructure Replacement Witness: Connie Taylor	PG&E does not expect to complete 227,557 feet of cable replacements out of the imputed 227,557 units. Program will be underspent by $134.9 million compared to imputed funding. Reasons: Reprioritization: PG&E is reprioritizing work in 56N to higher priority work in emergency replacements (MWC 17), capacity improvements (MWC 06,46), pole replacements (MWC 07). Network cable replacement work is expected to ramp up beginning in 2029, once PG&E's wildfire commitments have been completed.	Units: 227,557 Circuit Feet Cost: $135,552	Units: 0 Circuit Feet Cost: $644
7	Replace Obsolete UG Switches – Capital (MAT 56S) Chapter 16 –Underground Maintenance and Infrastructure Replacement Witness: Connie Taylor	PG&E does not expect to complete 142 units of LBOR switch replacements out of the imputed 308 units. Program will be underspent by approximately $3.0 million compared to imputed funding. Reprioritization: PG&E is reprioritizing work in 56S to higher priority work in emergency replacements (MWC 17), capacity improvements (MWC 06, 46), and pole replacements (MWC 07).	Units: 308 LBOR Switch Replacements Cost: $35,672	Units: 166 LBOR Switch Replacements Cost: $32,679
8	Install Temperature Indicator – Capital (MAT 56T) Chapter 16 –Underground Maintenance and Infrastructure Replacement Witness: Connie Taylor	PG&E does not expect to complete 4,276 units of TAD installations out of the imputed 9,176 units. Program will be underspent by $17.3 million compared to imputed funding. Reasons: PG&E is reprioritizing work in 56T to higher priority work in emergency replacements (MWC 17), capacity improvements (MWC 06,46), and pole replacements (MWC 07).	Units: 9,176 Installations Cost: $37,204	Units: 4,900 Installations Cost: $19,875

TABLE 2-5
LIST OF ELECTRIC DISTRIBUTION DEFERRED WORK PROGRAMS
(CONTINUED)

Line No.	Program, Chapter and Witness	Reason for Deferred Work	Imputed/ Adopted Units from the 2023 GRC (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast
9	-Replace Deteriorated Overhead Conductor – Capital (MAT 08J) Chapter 17 – Overhead Infrastructure Replacement and Reliability Witness: Tiffany Pazdan	PG&E does not expect to complete 255 miles of conductor replacement out of the imputed 295 miles. Program will be underspent by $165.7 million. Reasons: Reprioritization: PG&E is reprioritizing work in MAT 08J in order to perform Overhead Conductor Replacement in HFTD areas (MAT 08W) that reduces wildfire ignition risk. Funding that was not spent in 08J was reallocated to other high priority work in emergency replacements (MWC 17), capacity improvements (MWC 06,46), and pole replacements (MWC 07).	Units: 295 Circuit Miles Cost: $188,965	Units: 39 Circuit Miles Cost: $23,313
10	Overhead Fuses Install/Replace – Capital (MAT 49C) Chapter 17 – Overhead Infrastructure Replacement and Reliability Witness: Jon Eric Thalman	PG&E does not expect to complete 255 units of fuse replacements out of the imputed 515 units. Program will be overspent by $276 thousand. Reasons: PG&E spent more than imputed in this program in 2025 and 2026, however realized unit costs were higher than anticipated, resulting in fewer units being completed than forecast in the 2023 GRC. Recent updates to the standard requirements for this program have triggered additional work, such as the full replacement of the pole. Historically, the installation of fuses did not require a pole replacement. One of the benefits of these updates is that replacement enables easier upgrade to a Fuse Saver for future work.	Units: 515 Fused Cut-Out Locations Cost: $6,849	Units: 260 Fused Cut-Out Locations Cost: $7,125

TABLE 2-5
LIST OF ELECTRIC DISTRIBUTION DEFERRED WORK PROGRAMS
(CONTINUED)

Line No.	Program, Chapter and Witness	Reason for Deferred Work	Imputed/ Adopted Units from the 2023 GRC (2023-2026)	2023-2024 Recorded + 2025-2026 Forecast
11	Fault Location, Isolation and Service Restoration – Capital (MAT 49S) Chapter 17 – Overhead Infrastructure Replacement and Reliability Witness: Jon Eric Thalman	PG&E does not expect to complete 41 units of circuit activations out of the imputed 48 units. Program will be underspent by approximately $13.2 million. Reasons: PG&E is reprioritizing work in 49S to higher priority work in emergency replacements (MWC 17), capacity improvements (MWC 06,46), and pole replacements (MWC 07).	Units: 48 FLISR Circuit Activations Cost: $16,341	Units: 7 FLISR Circuit Activations Cost: $3,131
12	Replace Distribution Substation Breakers – Capital (MAT 48D) Chapter 18 – Substation Asset Management Witness: Maria Ly	PG&E does not expect to complete 144 units of breaker replacements out of the imputed 160 units. Program will be underspent by approximately $108.6 million. Reasons: PG&E is reprioritizing substation breaker replacements in order to support higher priority substation work in MWC 59. Rescheduling of these proactive replacements does not compromise safety or reliability.	Units: 160 Circuit Breakers Replaced Cost: $125,423	Units: 16 Circuit Breakers Replaced Cost: $16,805
13	Distribution Substation Animal Abatement – Capital (MAT 48X) Chapter 18 – Substation Asset Management Witness: Maria Ly	PG&E does not expect to complete 66 units of animal abatement locations out of the imputed 68 units. Program will be underspent by approximately $25.1 million. Reasons: PG&E is reprioritizing animal abatement work in order to support higher priority substation work in MWC 59. Rescheduling of these proactive replacements does not compromise safety or reliability.	Units: 68 Locations Cost: $25,292	Units: 2 Locations Cost: $211

c. Showing Required for Identified Deferred Work

For each work area identified as "deferred work" the Settlement requires that PG&E address the following:

a) Why the authorized work was not performed in the time forecasted;
b) Whether the deferral of the authorized work resulted in lower than authorized spending for the authorized work;
c) How the funding was reallocated and whether such reallocation related to the provision of safe and reliable service;
d) The reasonableness of the alternative work for the purpose of evaluating the appropriateness of the new funding request; and
e) How the specific funding request is consistent with the deferred work principles.

For the areas of deferred work identified by Electric Distribution, elements (a) through (d) are addressed for each deferred work area by the witnesses in the chapters referenced in Table 2-5. PG&E also discusses element (c) generally for Electric Distribution below, along with item (e), to show Electric Distribution's compliance with the six principles of deferred work for all 14 deferred work areas. The reasonableness of the alternative work is addressed below as part of responding to Question (c).

1) Response to Question (C) for Electric Distribution Expense Programs

Table 2-6 summarizes the recorded and forecast expense compared to imputed adopted for the four areas identified as deferred work.[11]

[11] See Exhibit (PG&E-4), WP 2-19.

TABLE 2-6
ELECTRIC DISTRIBUTION EXPENSE DEFERRED WORK PROGRAMS SUMMARY
(THOUSANDS OF NOMINAL DOLLARS)

Line No	2027 GRC Chapter	Description	2023 to 2024 Rec. Adj. + 2025 to 2026 Forecast	2023 to 2026 Imputed	Difference
1	14	Underground Manhole Inspections (MAT BFF)	$1,722	$2,040	$(318)
2	14	Overhead Equipment Testing (MAT BFG)	11,241	10,683	558
3	15	Pole Test & Treat (MAT GAA)	42,131	86,456	(44,325)
4	15	Pole Analyze Loading (MAT GAC)	51,354	90,607	(39,252)
5		Total	$106,448	$189,786	$(83,338)

PG&E expects to spend less than the imputed adopted amounts in the MAT codes where all units will not be completed, except for MAT BFG where PG&E anticipates spending the imputed adopted amount but for fewer units than originally forecast. For inspection work in MAT BFF, funding is reprioritized to enable transition from ground-based inspections to aerial inspections. Aerial Inspections leverages drones and other aerial means to inspect overhead electric distribution facilities to examine and record abnormal conditions that will adversely impact safety or reliability. Successful pilots have demonstrated that aerial inspections capture a variety of asset conditions that are challenging to see from a ground vantage point, including emergency conditions.

Pole Test and Treat funding (MAT GAA) was reprioritized to address other high priority inspection work including Aerial Inspections. It was reasonable to reprioritize these funds as the recorded and forecast units are still compliant with GO 165 requirements. In the 2023 GRC period the Pole Test and Treat program is focused on Comprehensive Pole Inspections, which help inform and prioritize EC notifications to determine if the work needs to be performed. This has resulted in completion of fewer units as there are not the same work efficiencies available compared to routine inspections.

Funding for Pole Loading Analysis (MAT GAC) work not forecast to be completed was re-allocated to routine emergency

work. It was reprioritize these funds based on the program's need to focus on exclusively on desktop review of HFTD poles as described above in Table 2-6, Line 4.

2) Response to Question (C) for Electric Distribution Capital Programs

Table 2-7 summarizes the recorded and forecast capital expenditures compared to imputed adopted for the areas identified as deferred work.[12]

TABLE 2-7
ELECTRIC DISTRIBUTION CAPITAL DEFERRED WORK PROGRAMS SUMMARY
(THOUSANDS OF NOMINAL DOLLARS)

Line No	2027 GRC Chapter	Description	2023 to 2024 Rec. Adj. + 2025 to 2026 Forecast	2023 to 2026 Imputed	Difference
1	16	Reliability Cable Replacement (MAT 56A)	$83,731	$162,355	$(78,624)
2	16	Network Cable Replacement (MAT 56N)	644	135,552	(134,908)
3	16	Replace Obsolete Underground Switches (MAT 56S)	32,679	35,672	(2,993)
4	16	Install Temperature Indicator (MAT 56T)	19,875	37,204	(17,328)
5	17	Overhead Conductor Replacement Program (MAT 08J)	23,313	188,965	(165,651)
6	17	Overhead Fuses (MAT 49C)	7,125	6,849	276
7	17	Fault Location, Isolation and Service Restoration (MAT 49S)	3,131	16,341	(13,209)
8	18	Replace Distribution Substation Breakers (MAT 48D)	16,805	125,423	(108,618)
9	18	Distribution Substation Animal Abatement (MAT 48X)	211	25,292	(25,081)
10		Total	$187,516	$733,653	$(546,137)

For capital work identified as deferred, PG&E expects to spend less than imputed adopted amounts as shown above, except for Overhead Fuses (MAT 49C) where PG&E forecasts spend above imputed adopted but will not complete forecast units. For substation breakers (MAT 48D) and animal abatement (MAT 48X), funding was reprioritized to address other work within the substation program, notably Emergency Substation Replacements (MWC 59). The work funded in MWC 59 is for emergency component replacements. This

[12] See Exhibit (PG&E-4), WP 2-19.

emergency replacement work is critical to complete to ensure substation safety and reliability.

Underground asset replacement work (MWC 56) was reprioritized to execute emergency replacements (MWC 17), capacity improvements (MWC 06, 46), and pole replacements (MWC 07).

The overhead asset replacement work and reliability work (MATs 08J, 49C, and 49S) were determined to be a lower near-term priority in the 2023 GRC period to allow increased focus on distribution line and capacity work, compliance pole replacements, and urgent routine emergency work. Additionally, the Company focus for overhead conductor replacements is on completing system hardening work in HFTD areas. Reliability work in MATs 49C and 49S are lower priority. These programs, while effective at mitigating overhead safety and reliability risk, are "proactive" replacement and equipment installation programs. When overhead resources and funding are needed for higher risk wildfire mitigation work, time-dependent work such as emergency replacement, and high risk time-dependent maintenance work, PG&E weighs this time dependency against the risks associated with not completing the full annually-forecasted proactive replacement and equipment installation work.

d. Consistency of Electric Distribution's Funding Request With The Six Principles of Deferred Work

The Deferred Work Settlement lists six principles. The Settlement requires that for all work meeting the definition of deferred work:

> PG&E's direct showing in support of the reasonableness of its forecast in the rate case shall provide at a minimum, a demonstration of how the specific funding request is consistent with the principles…

As stated in the Deferred Work Settlement, the six principles below should be viewed "in totality" and not in isolation. PG&E describes each principle and its key element(s) in order to provide additional structure for this discussion; these should be considered when determining

whether PG&E's decisions are reasonable for the operation of its systems.

Overall, Electric Distribution's re-request for funding of part of the work identified as "deferred work" under the Settlement, is reasonable, justified, and consistent with the six principles because: (1) sound operational reasons justify not fully performing all the units of work; (2) the deferrals maintained or enhanced system safety and reliability; and (3) in the cases where the deferral resulted in underspending compared to authorized amounts, the funds were re -directed to higher priority work.

Principle 1 – "*Where funds are originally collected from ratepayers based on representations that the work is necessary to provide safe and reliable service and, yet, PG&E does not perform all of the designated work, the fact that PG&E must pay for a higher priority activity or program does not nullify or extinguish its responsibilities to fund forecasted and authorized work unless such work is no longer deemed necessary for safe and reliable service."*

PG&E believes that the intention of this principle is to require funding by PG&E of all work needed to deliver safe and reliable service[13] regardless of other funding demands.

Electric Distribution has met and will meet the requirement to provide safe and reliable service in 2023-2026. The Company's enterprise-wide planning and budgeting process ensures that necessary work is funded. The BPD process provides an enterprise-level forum for Functional Areas to seek additional funding to address changing conditions and emergent high priority work. Following the Company's enterprise-wide planning and budgeting process, and consistent with its "responsibility and its discretion to adjust priorities to accommodate changing conditions" (see Principle 5 below), Electric manages and reprioritizes its spending as described in Section C above. These

[13] Under Pub, Util, Code § 451 PG&E is required to "furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment and facilities…as are necessary to promote the safety, health, comfort and convenience of its patrons, employees, and the public."

processes—the BPD process and Electric Distribution's management of its portfolio—align spending to meet all of PG&E's operational obligations and provide safe and reliable service. The reasonableness of the deferral, reprioritization of funding, and the alternative work are summarized in Table 2-5 and addressed in detail by the witnesses in the chapters referenced in the table. Each of these deferred work items are consistent with the obligation to provide safe and reliable service.

In sum, for all Electric Distribution's "deferred work" items, PG&E's actions were reasonable, did not compromise safety and reliability, and in the cases where authorized funding was not spent, it was reprioritized to higher priority work. For these reasons, PG&E believes that Electric Distribution's deferred work decisions as described in this chapter were consistent with the obligation to provide safe and reliable service as required by Principle 1.

Principle 2 – *"PG&E is responsible for providing safe and reliable customer service whether or not its overall spending matches funding levels authorized or imputed in rates."*

PG&E understands this principle to mean that PG&E's responsibility to provide safe and reliable service is independent of PG&E's overall spending level. PG&E discusses this principle at an enterprise level in Exhibit (PG&E-2), Chapter 2.

As discussed under Principle 1, Electric Distribution demonstrates compliance with this principle and with its responsibility to provide safe and reliable service by following its budget planning and management process described in Section C above. Furthermore, as explained under Principle 1, the specific deferred work described in this exhibit will not compromise system safety or near-term reliability.

Finally, while mindful of authorized funding levels, Electric Distribution does not limit its spending to authorized levels if greater expenditures are needed to address safety concerns and meet reliability targets. As discussed above, Electric Distribution expects to spend more than the imputed amounts on both expense and capital programs and projects between 2023 and 2026. This increase in spending above imputed was necessary to address maintenance tag work, complete

Wildfire Mitigation Plan commitments, and to address cost increases, emerging work, and other conditions not forecast in the 2023 GRC. These decisions to spend above imputed funding on both the portfolio level and the individual MAT level are all reasonable and consistent with this principle, and with Principle 5 below which requires PG&E to adjust spending to meet changing conditions.

Principle 3 – *"PG&E bears the risk that, as a result of meeting spending obligations necessary to provide safe and reliable service, the earned rate of return may be less than the authorized return."*

PG&E understands that under this principle, PG&E is not guaranteed its authorized rate of return and PG&E's obligation to provide safe and reliable service may cause PG&E's earnings to be less than authorized.

PG&E discusses this principle at an enterprise level in Exhibit (PG&E-2), Chapter 2.

Principle 4 – *"While PG&E has finite funds to meet capital and operational needs, PG&E is not restricted to spending only up to the forecast adopted in a GRC."*

PG&E understands this principle to be closely related to Principle 2, with the important additional acknowledgment that PG&E has finite funds to meet its capital and operational needs.

PG&E discusses this principle at an enterprise level in Exhibit (PG&E-2), Chapter 2. With respect to Electric Distribution, please see the discussion regarding Principle 2 above.

Principle 5 – *"PG&E bears the responsibility—and has discretion—to adjust priorities to accommodate changing conditions after test year forecasts are adopted. Readjusting spending priorities, however, only involves the ranking and sequence of spending. Reprioritizing spending for new projects does not automatically justify postponing projects previously deemed necessary for safe and reliable service."*

PG&E understands this principle to be very similar to Principles 1-3, adding the explicit acknowledgment of PG&E's responsibility and discretion to readjust its spending priorities.

PG&E discusses this principle at an enterprise level in Exhibit (PG&E-2), Chapter 2. With respect to Electric Distribution, as explained in Section C above, spending is managed to deliver system safety and reliability; meet compliance, regulatory and public commitments; and perform mandatory work (including new and emergent work). Electric Distribution considers factors such as risk reduction, cost, efficiencies, the availability of PG&E and contractor resources, synergies with other work, and dependencies and requirements such as permitting and the different rules for working with California's counties and cities. As a result of this risk-informed planning and budgeting process, no project or program is "automatically" postponed. As previously discussed under Principle 1, with respect to the specific areas of deferred work identified by Electric Distribution, the deferrals were operationally reasonable and will not degrade system safety or near-term reliability.

Principle 6 – "*The GRC process is a tool in supporting PG&E's ongoing ability to provide safe and reliable service while affording a reasonable opportunity to earn its rate of return and thereby attract capital to fund its infrastructure needs. Adopted revenue requirements and the disposition of disputed ratemaking issues should be consistent with the goal of supporting PG&E's ability to provide safe and reliable service while maintaining its financial health and ability to raise capital.*"

PG&E understands this principle to add important financial counterweights to the operational points covered in Principles 1-5. PG&E discusses this principle at an enterprise level in Exhibit (PG&E-2), Chapter 2.

2. Compliance With Public Utilities Code Section 935 (Alex Sproul)

The Powering Up Californians Act requires electrical corporations to include in each GRC application a detailed analysis of its current qualified staffing level and future required staffing level for each job classification needed to carry out the advanced planning, engineering, and construction of electrical distribution systems needed to promptly energize customers

without compromising other necessary activities of the workforce.[14] This report is included in Attachment B.

F. Cost Tables

Tables below summarize the 2024 recorded and forecast expense and capital forecasts for Electric Distribution by program area and chapter.[15]

[14] Pub. Util. Code § 935 and 933(e).

[15] See Exhibit (PG&E-4), WP 2-12 and WP 2-13 for 2020 expense and capital recorded amounts and 2021-2026 forecast.

TABLE 2-8
2024-2027 EXPENSE COSTS BY PROGRAM AREA
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program Area	Chapter Mapping	2024 Actuals	2025 Forecast	2026 Forecast	2027 Forecast
1	DCPP Volumetric Performance Fee	2	–	–	–	$(181,947)
2	Wildfire	4, 5, 6, 7	$181,678	$228,070	$219,735	252,911
3	Vegetation Management	8	1,322,408	1,257,810	1,243,450	1,025,490
4	Customer and Load Growth	9, 10, 13	74,879	59,961	60,926	66,989
5	Emergency and Grid Ops	11, 12	408,537	257,771	257,991	284,609
6	Maintenance and Inspections	14, 15, 16, 17	344,808	323,755	322,766	491,521
7	Substation and Automation	18, 19	52,418	49,671	49,638	60,525
8	Technology, Data and Support	20, 21, 22, 23	181,689	169,561	164,867	147,558
9	Total		$2,566,416	$2,346,600	$2,319,374	$2,147,657

TABLE 2-9
2027 EXPENSE FORECAST BY CHAPTER AND PROGRAM AREA
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Chapter	Chapter Title	Customer & Load Growth	DCPP Volumetric Performance Fee	Emergency & Grid Ops	Maintenance & Inspections	Substation & Automation	Technology, Data & Support	Vegetation Management	Wildfire	2027 Forecast Total
1	2	Electric Distribution Forecast Summary and Investment Plan	–	$(181,947)	–	–	–	–	–	–	$(181,947)
2	4	Wildfire Mitigation Summary and Strategy Support	–	–	–	–	–	–	–	$27,802	27,802
3	5	Situational Awareness and Forecasting	–	–	–	–	–	–	–	34,408	34,408
4	6	Wildfire Operational Mitigations (PSPS, EPSS and Customer Battery Programs)	–	–	–	–	–	–	–	187,377	187,377
5	7	Wildfire System Hardening	–	–	–	–	–	–	–	3,325	3,325
6	8	Vegetation Management	–	–	–	–	–	–	$1,025,490	–	1,025,490
7	9	Electric Distribution Capacity, Engineering and Planning	$19,670	–	–	–	–	–	–	–	19,670
8	10	New Business and WRO	26,357	–	–	–	–	–	–	–	26,357
9	11	Electric Emergency Recovery	-	–	$210,732	–	–	–	–	–	210,732
10	12	Distribution System Operations	-	–	73,877	–	–	–	–	–	73,877
11	13	Field Metering	20,962	–	-	–	–	–	–	–	20,962
12	14	Distribution Inspections	-	–	-	$142,786	–	–	–	–	142,786
13	15	OH Maintenance and Poles	-	–	-	303,864	–	–	–	–	303,864
14	16	UG Maintenance and Infrastructure Replacement	–	–	–	44,872	–	–	–	–	44,872
15	18	Substation Asset Management	–	–	–	–	$58,496	–	–	–	58,496
16	19	Distribution System Automation and Protection	–	–	–	–	2,029	–	–	–	2,029
17	20	Electric Distribution Mapping and Data Management	–	–	–	–	–	$31,115	–	–	31,115
18	21	Electric Distribution and Wildfire Mitigation Information Technology	–	–	–	–	–	30,164	–	–	30,164
19	22	Grid Modernization and Grid Technology	–	–	–	–	–	13,653	–	–	13,653
20	23	Electric Distribution Support Activities	–	–	–	–	–	72,626	–	–	72,626
21		Total Expense	$66,989	($181,947)	$284,609	$491,521	$60,525	$147,558	$1,025,490	$252,911	$2,147,657

TABLE 2-10
2024-2030 CAPITAL EXPENDITURES BY PROGRAM AREA
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Program Area	Chapter Mapping	2024 Actuals	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast
1	Wildfire	4, 5, 6, 7	$1,060,422	$1,485,885	$1,421,526	$1,037,747	$382,633	$319,140	$366,236
2	Customer and Load Growth	9, 10, 13	1,874,687	2,001,557	1,884,028	2,063,137	2,223,044	2,327,835	2,408,848
3	Emergency and Grid Ops	11, 12	676,935	521,028	538,813	626,511	649,959	672,702	697,803
4	Maintenance and Inspections	15, 16, 17	1,134,036	1,131,224	1,093,756	2,247,246	2,460,781	2,617,214	2,943,278
5	Substation and Automation	18, 19	290,503	291,558	332,415	531,189	601,397	662,003	746,273
6	Technology, Data & Support	20, 21, 22, 23	261,166	188,163	148,099	188,473	166,400	190,129	198,360
7	Total		$5,297,749	$5,619,415	$5,418,637	$6,694,303	$6,484,213	$6,789,023	$7,360,799

TABLE 2-11
2027 CAPITAL FORECAST BY CHAPTER AND PROGRAM AREA
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Chapter No.	Chapter Title	Customer and Load Growth	Emergency and Grid Ops	Maintenance and Inspections	Substation and Automation	Technology and Data Support	Wildfire	2027 Forecast Total
1	4	Wildfire Mitigation Summary and Strategy Support	–	–	–	–	–	$6,393	$6,393
2	5	Situational Awareness and Forecasting	–	–	–	–	–	12,731	12,731
3	6	Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs)	–	–	–	–	–	69,679	69,679
4	7	Wildfire System Hardening	–	–	–	–	–	948,944	948,944
5	9	Electric Distribution Capacity, Engineering, and Planning	$534,768	–	–	–	–	–	534,768
6	10	New Business and WRO	1,489,647	–	–	–	–	–	1,489,647
7	11	Electric Emergency Recovery	–	$619,641	–	–	–	–	619,641
8	12	Distribution System Operations	–	6,870	–	–	–	–	6,870
9	13	Field Metering	38,722	–	–	–	–	–	38,722
10	15	OH Maintenance and Poles	–	–	$1,987,094	–	–	–	1,987,094
11	16	UG Maintenance and Infrastructure Replacement	–	–	183,165	–	–	–	183,165
12	17	Overhead Infrastructure Replacement and Reliability	–	–	76,987	–	–	–	76,987
13	18	Substation Asset Management	–	–	–	$492,069	–	–	492,069
14	19	Distribution System Automation and Protection	–	–	–	39,120	–	–	39,120
15	21	Electric Distribution and Wildfire Mitigation Information Technology	–	–	–	–	$76,033	–	76,033
16	22	Grid Modernization and Grid Technology	–	–	–	–	93,059	–	93,059
17	23	Electric Distribution Support Activities	–	–	–	–	19,381	–	19,381
18		Total Capital	$2,063,137	$626,511	$2,247,246	$531,189	$188,473	$1,037,747	$6,694,303

TABLE 2-12
2024-2027 EXPENSE COSTS BY CHAPTER
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Chapter No.	Chapter Name	2024 Actuals	2025 Forecast	2026 Forecast	2027 Forecast
1	2	Forecast Summary and Investment Plan	–	–	–	$(181,947)
2	4	Wildfire Risk Mitigations Summary	$28,599	$26,817	$27,192	27,802
3	5	Wildfire Situational Awareness and Forecasting	25,907	30,602	29,083	34,408
4	6	Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs)	122,994	167,371	160,840	187,377
5	7	Wildfire System Hardening	4,178	3,280	2,620	3,325
6	8	Vegetation Management	1,322,408	1,257,810	1,243,450	1,025,490
7	9	Electric Distribution Capacity, Engineering, and Planning	18,105	16,522	19,670	19,670
8	10	New Business and WRO	35,580	27,218	26,751	26,357
9	11	Electric Emergency Recovery	348,714	206,346	206,346	210,732
10	12	Grid Operations	59,824	51,425	51,645	73,877
11	13	Field Metering	21,194	16,222	14,505	20,962
12	14	Distribution Inspections	129,463	141,206	141,749	142,786
13	15	Overhead Maintenance and Poles	188,469	163,990	165,184	303,864
14	16	Underground Maintenance and Infrastructure Replacement	26,876	18,559	15,833	44,872
15	18	Substation Asset Management	50,485	47,608	47,608	58,496
16	19	Distribution System Automation and Protection	1,933	2,063	2,029	2,029
17	20	Electric Distribution Mapping and Data Management	29,421	31,744	29,678	31,115
18	21	Electric Distribution Technology	40,299	36,284	36,300	30,164
19	22	Grid Modernization and Grid Technology	22,631	29,065	27,497	13,653
20	23	Electric Distribution Support Activities	89,338	72,467	71,392	72,626
21		Total	$2,566,416	$2,346,600	$2,319,374	$2,147,657

TABLE 2-13
2024-2027 CAPITAL COSTS BY CHAPTER
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Chapter No.	Chapter Name	2024 Actuals	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast
1	4	Wildfire Risk Mitigations Summary	$5,978	$6,230	$6,330	$6,393	$6,489	$6,593	$6,705
2	5	Situational Awareness and Forecasting	11,286	15,080	12,744	12,731	12,935	12,196	11,094
3	6	Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs)	61,522	61,175	55,889	69,679	81,692	77,785	78,459
4	7	Wildfire System Hardening	981,636	1,403,400	1,346,563	948,944	281,517	221,567	269,978
5	9	Electric Distribution Capacity, Engineering, and Planning	317,497	479,213	611,635	534,768	698,628	767,207	810,643
6	10	New Business and WRO	1,526,011	1,497,066	1,247,116	1,489,647	1,483,422	1,517,224	1,552,244
7	11	Electric Emergency Recovery	670,992	515,287	533,813	619,641	643,460	667,202	692,303
8	12	Distribution Systems Operations	5,943	5,741	5,000	6,870	6,500	5,500	5,500
9	13	Field Metering	31,179	25,278	25,278	38,722	40,994	43,404	45,961
10	15	OH Maintenance and Poles	931,503	958,266	895,281	1,987,094	2,122,227	2,245,808	2,552,874
11	16	UG Maintenance and Infrastructure Replacement	165,236	143,750	164,638	183,165	236,077	264,768	277,799
12	17	Overhead Infrastructure Replacement and Reliability	37,297	29,208	33,837	76,987	102,477	106,638	112,605
13	18	Substation Asset Management	268,776	257,067	300,781	492,069	562,327	622,970	708,118
14	19	Distribution System Automation and Protection	21,727	34,492	31,634	39,120	39,070	39,033	38,155
15	21	Electric Distribution Technology	103,098	48,850	50,170	76,033	61,219	87,791	91,824
16	22	Grid Modernization and Grid Technology	141,658	118,294	78,532	93,059	85,553	83,604	89,133
17	23	Electric Distribution Support Activities	16,409	21,019	19,396	19,381	19,628	18,735	17,404
18		Total	$5,297,749	$5,619,415	$5,418,637	$6,694,303	$6,484,213	$6,789,023	$7,360,799

G. Conclusion

The Electric Distribution plan is based on a prioritized and validated set of work which meets regulatory requirements, delivers on key commitments, and serves customers' needs. The plan was risk-prioritized and checked for cost effectiveness using PG&E's risk standards, namely RBPPF. Additionally, the plan includes programs with non-standard forecasts which need special consideration during the review (Section C.1.b and C.2.b) because they do not follow the standard attrition year escalation trajectory.

1. Testimony Attachments

- Attachment A: Exhibit/Chapter mapping Changes since 2023 GRC; and
- Attachment B: Public Utilities Code Section 935 Report.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT A

EXHIBIT CHANGES SINCE THE 2023 GRC

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ATTACHMENT A
EXHIBIT CHANGES SINCE THE 2023 GRC

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PACIFIC GAS AND ELECTRIC COMPANY
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ATTACHMENT A
EXHIBIT CHANGES SINCE THE 2023 GRC

PG&E reorganized the Electric Distribution exhibit as compared to the 2023 GRC exhibit by adding new chapters and reorganizing the way work is presented. The most notable changes are listed below.

A. Reorganization of Wildfire Risk Mitigation Testimony

PG&E consolidated most of its discussion of Wildfire Risk Mitigations in the following chapters:

- Chapter 4, “Wildfire Risk Mitigations Summary;”
- Chapter 5, “Situational Awareness and Forecasting;”
- Chapter 6, “Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs);” and
- Chapter 7, “Wildfire System Hardening.”

Other chapters that include wildfire mitigations are:

- Chapter 8, “Vegetation Management;”
- Chapter 15, “Overhead Maintenance and Poles;”
- Chapter 18, “Substation Asset Management;” and
- Chapter 21, “Electric Distribution and Wildfire Mitigation Information Technology.”

B. Other Organizational Changes

In this GRC, PG&E has re-ordered and restructured some chapters. This includes a different presentation for maintenance programs that in the 2023 GRC were all included in Chapter 11, “Overhead and Underground Electric Distribution Maintenance.” In the 2027 GRC, the programs in that chapter have been separated out into the following three chapters: (1) Chapter 15, “Overhead Maintenance and Poles” (MWCs KA and 2A); (2) Chapter 16, “Underground Maintenance and Infrastructure Replacement” (MWCs KB and 2B); and (3) Chapter 23, “Electric Distribution Support Activities” (MWC BK). This separation allows for a more focused evaluation of the respective programs and/or better aligns with PG&E’s current organizational structure.

Emergency Preparedness and Response has moved from Exhibit (PG&E-4), Chapter 5, “Emergency Preparedness and Response” in the 2023 GRC to Exhibit (PG&E-7), Chapter 9, “Emergency Preparedness and Response” in the 2027 GRC based on organizational structure.

Gas AMI Modules and Infrastructure (MWC 74) has moved from Exhibit (PG&E-4), Chapter 8, “Field Metering” in the 2023 GRC to Exhibit (PG&E-6), Chapter 6, “Gas AMI Program” in the 2027 GRC based on organizational structure.

Table 2-1 below compares the 2023 GRC presentation to the 2027 GRC presentation by chapter name and the MWCs presented in each chapter.

TABLE 2-1
COMPARING THE 2023 GRC TO 2027 GRC CHAPTERS

Line No.	2023 GRC		2027 GRC	
	Chapter Number and Title	MWCs	Chapter Number and Title	MWCs
1	Chapter 1: Electric Distribution Policy and Introduction	None	Chapter 1: Electric Distribution Policy and Introduction	None
2	Chapter 2: Electric Distribution Forecast and Investment Planning	All	Chapter 2: Electric Distribution Forecast and Investment Planning	All
3	Chapter 3: Electric Distribution Risk Management	None	Chapter 3: Electric Distribution Risk Management	None
4	Chapter 4: Wildfire Risk Mitigations	Exp: AB, FZ, GE, IG, JV Cap: 21, 2F, 08, 48, 49	Chapter 4: Wildfire Mitigation Summary and Strategy Support	Exp: AB Cap: 21
5			Chapter 5: Situational Awareness and Forecasting	Exp: AB, FZ, WF Cap: 21, 3U
6			Chapter 6: Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs)	Exp: BA, BH, DD, FZ, GC, HX, IG, WF Cap: 3U, 09, 49, 48, 21
7			Chapter 7: Wildfire System Hardening	Exp: AB, GE Cap: 08, 3U, 21
8			Chapter 21: Electric Distribution and Wildfire Mitigation Information Technology	Exp: IG, JV Cap: 2F
9	Chapter 5: Emergency Preparedness and Response	Exp: AB Cap: 21	Exhibit (PG&E-7), Chapter 9: Emergency Preparedness and Response	Exp: AB, JV, IG, WF, ZC Cap: 21, 2F
10	Chapter 6: Electric Emergency Recovery	Exp: IF, BH Cap: 17, 95	Chapter 11: Electric Emergency Recovery	Exp: IF, BH Cap: 17, 95
11	Chapter 7: Distribution System Operations	Exp: BA, DD, HG Cap: 63	Chapter 12: Distribution System Operations	Exp: BA, DD, HG Cap: 63
12	Chapter 8: Field Metering	Exp: AR, DD, EY, EZ, HY, IU Cap: 25, 74	Chapter 3: Field Metering	Exp: AR, DD, EY, EZ, HY, IU Cap: 25
13			Exhibit (PG&E-6), Chapter 8: Gas AMI Program	Cap: 74

TABLE 2-1
COMPARING THE 2023 GRC TO 2027 GRC CHAPTERS
(CONTINUED)

Line No.	2023 GRC		2027 GRC	
	Chapter Number and Title	MWCs	Chapter Number and Title	MWCs
14	Chapter 9: Vegetation Management	Exp: HN, IG Cap: None	Chapter 8: Vegetation Management	Exp: HN, IG Cap: None
15	Chapter 10: Overhead and Underground Electric Asset Inspections	Exp: BF Cap: None	Chapter 17: Distribution Inspections	Exp: BF Cap: None
16	Chapter 11: Overhead and Underground Electric Distribution Maintenance	Exp: BK, KA, KB Cap: 2A, 2B	Chapter 15: Overhead Maintenance and Poles	Exp: KA Cap: 2A
17			Chapter 16: Underground Maintenance and Infrastructure Replacement	Exp: KB Cap: 2B
18			Chapter 23: Electric Distribution Support Activities	Exp: BK
19	Chapter 14: Network Asset Management	Exp: KC Cap: 2C, 56	Chapter 16: Underground Maintenance and Infrastructure Replacement	Exp: KC Cap: 2C, 56
20	Chapter 12: Pole Asset Management	Exp. GA Cap: 07	Chapter 15: Overhead Maintenance and Poles	Exp. GA Cap: 07
21	Chapter 13: Overhead and Underground Asset Management and Reliability	Exp: None Cap: 08, 49, 56	Chapter 17: Overhead Infrastructure Replacement and Reliability	Exp: None Cap: 08, 49
22			Chapter 16: Underground Maintenance and Infrastructure Replacement	Exp: None Cap: 56
23	Chapter 16: Distribution System Automation and Protection	Exp. HX Cap: 09	Chapter 19: Distribution System Automation and Protection	Exp. HX Cap: 09
24	Chapter 15: Substation Asset Management	Exp: GC Cap: 48, 54, 58, 59	Chapter 18: Substation Asset Management	Exp: GC Cap: 48, 54, 58, 59
25	Chapter 17: Electric Distribution Capacity, Engineering and Planning	Exp: FZ Cap: 06, 46	Chapter 9: Electric Distribution Capacity, Engineering, and Planning	Exp: FZ Cap: 06, 46

TABLE 2-1
COMPARING THE 2023 GRC TO 2027 GRC CHAPTERS
(CONTINUED)

Line No.	2023 GRC		2027 GRC	
	Chapter Number and Title	MWCs	Chapter Number and Title	MWCs
26	Chapter 18: New Business and Work at the Request of Others	Exp: EV, EW Cap: 10. 16	Chapter 10: New Business and Work at the Request of Others	Exp: EV, EW Cap: 10. 16, 30
27	Chapter 19: Rule 20A	Exp. IG Cap: 30		
28	Chapter 20: Electric Distribution Data Management and Technology	Exp. GE, JV Cap: 21, 2F	Chapter 20: Electric Distribution Mapping and Data Management	GE
29			Chapter 21 Electric Distribution and Wildfire Mitigation Information Technology	Exp: JV Cap: 2F
30	Chapter 21: Integrated Grid Platform and Grid Modernization Plan	Exp: AB, AT, HG, IG, JV Cap: 21, 2F, 3M, 3R, 63, 82	Chapter 22: Grid Modernization and Grid Technology	Exp: AB, AT, HG, IG, JV Cap: 21, 2F, 3M, 3R, 63, 82
31	Chapter 22: Electric Distribution Support Activities	Exp: AB, IS, OM, OS Cap: 05, 21	Chapter 23: Electric Distribution Support Activities	Exp: AB, IS, OM, OS Cap: 05, 21
32	Chapter 23: Community Rebuild Program	Exp: IF Cap: 95	Not included in 2027 GRC	

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT B

PUBLIC UTILITIES CODE SECTION 935 REPORT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ATTACHMENT B
PUBLIC UTILITIES CODE SECTION 935 REPORT

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PACIFIC GAS AND ELECTRIC COMPANY
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PUBLIC UTILITIES CODE SECTION 935 REPORT

A. Executive Summary and Overview

Pacific Gas and Electric Company (PG&E) presents the following report on its current and potential future Electric Distribution staffing needs for work forecast in Exhibit (PG&E-4). PG&E submits this report in compliance with Public Utilities Code (Pub. Util. Code) Section 935.

PG&E's Electric Distribution organization currently employs over 10,700 coworkers, which includes approximately 5,100 International Brotherhood of Electrical Workers (IBEW) union-represented coworkers, and over 3,000 Engineers and Scientists of California (ESC) union-represented coworkers. Based on the 2027 General Rate Case (GRC) forecast for Electric Distribution presented in Exhibit (PG&E-4), PG&E's projects a potential need to increase the headcount for its internal workforce by approximately 1,300 employees by 2030 in order to match the forecasted volume of work. Lineworkers, engineers, apprentices (across several apprentice types), crew leads, estimators, and electricians account for the majority of the headcount increase. PG&E anticipates growing its linework, cable splicer, electrician, and distribution system operator apprentice pipelines to scale with the forecasted volume of work.

To the extent that work volumes changes, PG&E's headcount projections would similarly change. PG&E projects hiring plans multi-year and adjusts hiring plans on an annual basis based on workplan needs. Further, the hiring plans can be adjusted in-year as business needs arise or change.

The remainder of this report is divided into five sections:

- Section B – Framework for the Report: This section provides an overview of the Powering Up Californians Act, which requires this Pub. Util. Code Section 935 Report. This section further explains how PG&E has implemented Section 935 for this report.

- Section C – Overview of PG&E's Workforce Planning and Strategy: This describes PG&E's current workforce planning process, strategy, and deployment.
- Section D – Current Staffing and Adequacy to Meet Demand: This discussion discusses existing staffing levels and how these levels are generally adequate to meet overall electric distribution needs.
- Section E – Future Staffing Analysis: This section describes the methodology for forecasting potential future staffing needs by job groupings, based upon PG&E's Electric Distribution forecasts in this GRC. The analysis takes into consideration the type of electric distribution work forecasted compared to the work PG&E's workforce complete today.
- Section F – Apprentice Pipeline Analysis: This section describes PG&Es key apprentice programs that develop a pipeline for maintaining a sufficiently-sized qualified workforce to carryout electric distribution work. This section also discusses how PG&E plans to scale these apprenticeship programs to meet future potential staffing needs.

B. Framework for this Report

1. Basis for Pub. Util. Code 935 Report: The Powering Up Californians Act

In 2023, the California legislature enacted the Powering Up Californians Act (Act) setting forth state policy that upgrades to the electrical corporations' distribution systems are critical to meet the state's decarbonization goals, comply with their obligation to serve customers, and ensure that housing, businesses, and electric transportation vehicles can be used without delays.[1] Part of the impetus for the Act was a rising concern over electrical corporations' ability to timely energize customer requests.[2] As part of this policy, the legislature determined that electrical corporations must recruit, train, and retain an adequately-sized qualified workforce to complete the energization work to upgrade electrical distribution systems and promptly connect customers without sacrificing other necessary

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1 Pub. Util. Code § 933(a-d).

2 Pub. Util. Code § 932(a)(3-4).

activities to maintain the safety and reliability, such as wildfire mitigation, inspection and maintenance activities, and other critical work.[3] The Act also finds that the California Public Utilities Commission shall require the electrical corporation to have adequate qualified staffing and maintain a pipeline of apprentices to achieve these policies.[4]

To ensure that electrical corporations meet this workforce policy, the Powering Up Californians Act, Section 935, requires electrical corporations to include in each GRC application a detailed analysis of its current qualified staffing level and future required staffing level for each job classification needed to carry out the advanced planning, engineering, and construction of electrical distribution systems needed to promptly energize customers, while still completing other required work.[5]

2. PG&E's Approach to the Pub. Util. Code 935 Report

While most provisions in the Powering Up California Act focus on the funding and timely completion of *energization* work (customer connections and capacity projects), Section 935 addresses staffing needs for both *energization* work and other electric work for maintaining safety and reliability. PG&E therefore assessed staffing needs not by a specific type of electric distribution work, but instead assessed those needs holistically across its full portfolio of electric distribution work. This is because labor resources work across electric distribution programs and PG&E must constantly evaluate the need to adjust its use of resources (internal and external) for that work. For instance, a lineworker may work on New Business capital projects (energization), distribution maintenance, or system operations. As a result, the staffing-level analysis presented in this Report includes the labor that supports energization work, as well as other electric distribution work. PG&E believes that this captures the intent of the statute to ensure that electrical corporations retains a sufficiently-sized qualified workforce to timely energize customers without sacrificing the other activities completed by the workforce.

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3 Pub. Util. Code § 933(e).

4 Pub. Util. Code § 935(b-c).

5 Pub. Util. Code § 935(a).

In addition, while PG&E's advanced planning, engineering, and construction activities are generally performed by its asset management, estimating, and construction groups, respectively, numerous other job groups that may not fit squarely in these three categories are critical parts of planning, building, and maintaining PG&E's electric distribution system. To provide a detailed analysis, this report includes 32 different job groupings that perform the planning, engineering, construction, and more. These groupings are consistent with how PG&E categorizes job titles (and associated job identification codes) at the enterprise level. The specific job titles in the Electric Distribution organization associated with each job grouping is provided in Appendix 1.

This Report provides an overview of PG&E's workforce planning approach to illustrate key considerations for meeting total workforce needs. The potential staffing needs identified in this Report could be met through a combination of strategies, such as training labor, recruiting trained labor, or taking actions to retain existing trained labor that is at risk of departing. The appropriate strategy for a specific job position varies, depending on the geographic location and urgency of staffing needs. However, PG&E provides additional information on how it would scale its apprenticeship pipeline to maintain a sufficiently-sized qualified workforce to meet future increased demand for electric distribution work.

In summary, PG&E's approach to this Pub. Util. Code Section 935 report is intended to be fully-inclusive of all electric distribution staffing needs to complete forecasted electric investments for our distribution grid through 2030. PG&E is mindful of the volume of its GRC showing, including this Section 935 Report, and the capacity and resource limitations the Commission and parties may have in reviewing the materials. Accordingly, PG&E has streamlined its showing to make this report more accessible to the Commission and parties rather than present the possible volume of information that could be considered relevant to its requests and proposals. PG&E expects parties to seek additional information of interest through discovery and PG&E is prepared to respond to data requests, hold workshops, as well as submit additional testimony and add other information

to add to the evidentiary record as may be of interest to parties, consistent with Commission Rule 13.

C. PG&E's Current Workforce Planning and Staffing

1. Overview of Workforce Planning and Strategy

PG&E examines its hiring needs annually based on the company's workplan needs. Investment planning teams select workplans (scope and timing) and establish financial targets based on the company's risk prioritization, regulatory requirements, and other strategic goals (such as maintaining affordability). Once the work and budget are determined, the specific departments assigned the work determine whether any headcount adjustments are necessary. Requests for additional headcount are analyzed by workforce planning and strategy teams to determine whether the additional headcount request satisfies various criteria, including: (1) long-term hiring needs; (2) collective bargaining agreements with IBEW and ESC, (3) regional staffing needs, and (4) other budget considerations. These factors are discussed in greater detail below.

PG&E's staffing-level analyses generally are only completed for departments that complete programmatic, planned work.[6] The analyses must be completed to ensure that the work can be executed by internal resources in alignment with the scope, timing and budget established for the work. PG&E utilizes its existing workforce to meet forecasted and priority needs; any residual, larger, or complex/specialized work is assigned to qualified contractors.

PG&E has enhanced its work-planning process in recent years to consider multi-year investment needs and opportunities to bundle work activities to drive cost efficiencies. This multi-year workplan view has presented the added benefit of visibility for longer-term hiring needs. PG&E is in the process of developing a more centralized and longer-term labor resource planning approach. This will enhance PG&E's ability to leverage its apprenticeship programs, which are multi-year training programs to meet

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[6] Certain work is generally excluded from staffing-level analyses if the staffing levels necessary to complete the work are subject to annual fluctuations due to the emergent nature of the work. Examples of these type of programs include emergency response and emergent maintenance work.

future needs for a trained workforce. Lastly, the visibility into longer-term workforce needs enables PG&E to stage its hiring and recruitment efforts over time. In other words, when PG&E anticipates a need to hire 1,000 employees (for example), not all hiring would necessarily occur in one year, but would be staged over multiple years. The timing of hiring for each job category would be based on the urgency and recruitment needs of that position.

a. Long-Term Staffing Needs

When there is an increase in a particular work activity in the near-term, PG&E first considers whether the level of work activity will remain long-term before hiring additional staff. This ensures that any additional headcount will not sit idle or be subject to layoffs if the level of work activity is likely to decrease in the future. Instead, PG&E will use contract labor to meet short-term staffing needs to complete the work.

When work levels indicate that additional staff is warranted in the long-term, PG&E scales the workforce linearly from its existing 60 percent internal/external ratio. On average, PG&E utilizes contract labor to supplement approximately 40 percent of planned work, typically larger or complex/specialized work.

The rationale for using external labor for a portion of the work is because the volume of staff needed throughout the year varies by season and emergent events. As a result, PG&E plans for internal staffing that is sufficient to address work needs in the lowest demand periods, and not the highest demand periods. PG&E does not hire internal staff above what is needed to execute work during the lowest demand periods, otherwise PG&E staff would sit idle in the low demand periods, which is not in the interest of affordability. As a result, contract labor is core aspect of PG&E's workforce strategy. Contract labor enables PG&E to quickly scale the workforce as needed.

b. Collective Bargaining Agreement Requirements

PG&E has three collective bargaining agreements (CBA). The IBEW-Clerical CBA governs the terms of employment for customer service, clerks, and job positions that are more administrative in nature.

The IBEW-Physical CBA governs the terms of employment for field employees such as lineworkers and electricians. The ESC CBA governs the terms of employment for engineers, project managers, contract administrators, and other technical specialists. Each CBA (including modifications to the CBA through letter agreements) determines the skills and qualifications necessary for each union-represented position, as well as the line of progression for employees.[7] Certain high-skill or safety-critical positions require completion of multi-year training programs or apprenticeships, which include on-the-job training. The IBEW-Physical CBA also establishes standards for on-the-job training, including how many trained employees (journey workers) are on a worksite relative to trainees (apprentices) to ensure adequate oversight and teaching opportunities (i.e., Training Labor Ratio).

The terms of each CBA are an important factor in the strategy and rate at which PG&E can adjust its overall headcount. For example, PG&E can only hire apprentice workers to the extent there are journey workers available to train the apprentices in accordance with the Training Labor Ratio. While PG&E prefers to develop its workforce through its apprentice programs, when trained labor is needed immediately, PG&E may opt for hiring trained labor or seek to retain existing trained personnel (if they are seeking alternate positions).

c. Regional Labor Needs

PG&E's workforce resides in communities throughout our service territory, which expands across central and northern California. Employees are assigned to regional offices, service centers, or service yards. When assessing workforce needs, PG&E takes into consideration where the work demand is regionally. If work demand is growing in a region, the ability to hire apprentices to meet that demand is limited by the number of journey workers assigned to that service yard to remain compliant with the Training Labor Ratio. However, if work

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7 A line of progression is the sequence of trainings and job levels to advance responsibilities and, often, pay.

demand is flat or decreasing in a region but is fully staffed with trained labor, PG&E may not offer apprentice positions because there is not local workforce need.

d. Other Budget Considerations

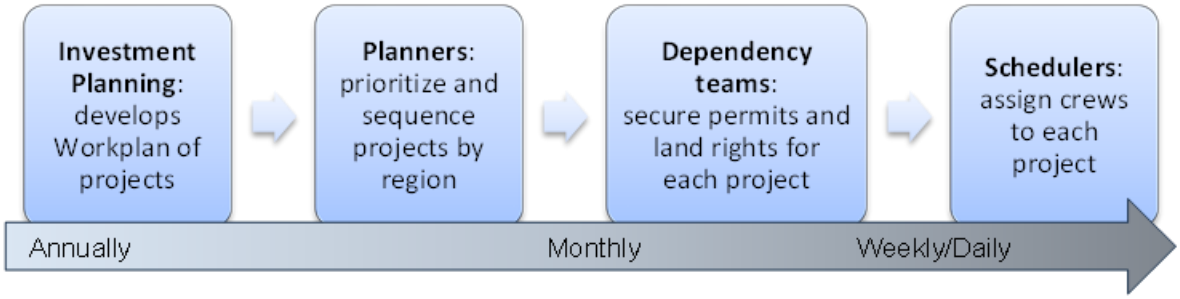
When a department requests additional headcount, a portion of the costs to accommodate additional headcount impacts the budgets of other organizations. For instance, additional headcount for lineworkers requires additional trucks, equipment, and IT support. Additional headcount also impacts medical and other benefits budgets. Thus, the timing and rate of headcount increases must be coordinated with the budget and ability of other functional areas and departments to support the additional headcount.

On a related note, when an organization has persistent charges to overtime orders (thus increasing costs), PG&E prioritizes hiring in these areas. For example, if we plan for overtime hours in the annual budget but the overtime hours exceeds the planned amount at year-end, and this continues for two or three years, we focus on increasing headcount in those areas. For example, recorded data for distribution system operator positions indicates overtime spending above PG&E's budget goals, and therefore we have a goal of adding 80 distribution system operator roles. Adding internal labor in these scenarios is less costly for our customers compared to paying overtime.

2. Deploying the Workforce

PG&E's workplans identify by region and order number all planned work to be completed in an upcoming year. The workplans provide visibility on the amount of work that will be performed in the region, and whether contract resources will be necessary to supplement any regional work. To the extent that additional external labor resources are needed, PG&E's sourcing department will utilize existing agreements with labor contractors to procure bids for short-term labor needs.

FIGURE 2B-1
WORKFORCE DEPLOYMENT

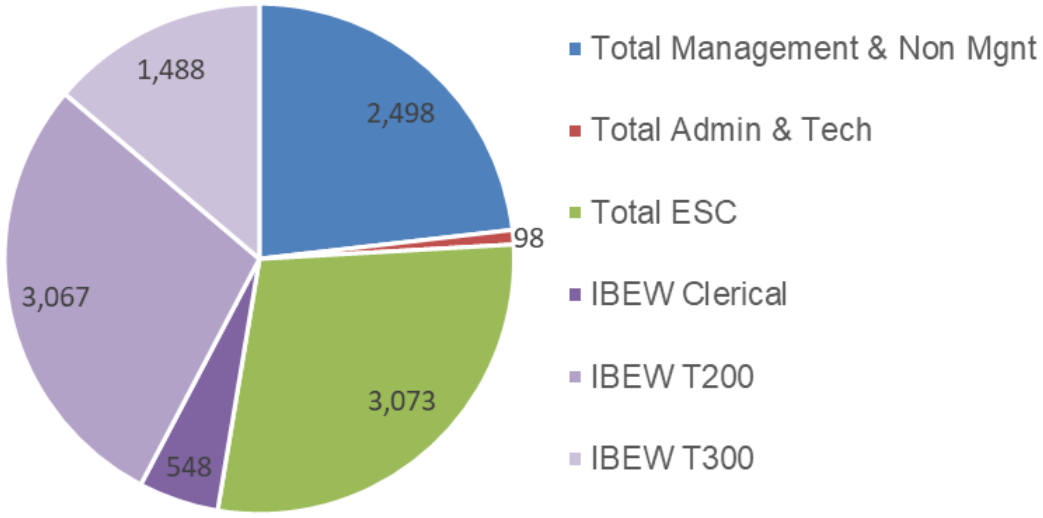


The orders associated with a project are then sequenced and scheduled. Estimating planners view workplans to determine the timeline and sequence for estimators to complete their work. The construction planners sequence the orders in each region to align with priorities and regional needs for completing work. A dependencies team uses the workplan along with the estimating and construction's sequencing plans to develop a plan for securing permits and acquiring land rights (if needed). Schedulers then assign crews (either internal or external) to complete the work per the CBA. Schedulers must take into consideration the crew size needed for a project, and that all labor ratios meet the CBAs and letter agreements. Figure 2B-1 shows this workforce deployment process at a high-level, including the general frequency of the activity.

D. Current Staffing and Adequacy to Meet Demand

PG&E's workforce supporting Electric Distribution activities includes over 10,700 employees, including approximately 5,100 IBEW-represented employees and over 3,000 ESC-represented employees.

FIGURE 2B-2
2025 YEAR-TO-DATE ELECTRIC DISTRIBUTION WORKFORCE



Note: Year-to-Date is as of April 20, 2025.

PG&E's overall workforce supporting Electric Distribution has steadily grown since 2020 to keep pace with the level of work required. Table 2B-1 shows the change in staffing by job grouping between 2020-2025 (year to date).[8] Lineworkers, Utility Workers, Coordinators, Engineers, and Analyst/Specialists have all grown more than 30 percent since 2020 and have seen the greatest amount of net growth within the electric organization. Other job groupings, such as cable splicers, clerical workers, field technicians, and technicians, have remained steady or decreased despite overall electric distribution work level increasing over the 2020-2025 period.

8 Table 2B-1 includes job groupings that appear to have no or few employees. This is because that job grouping primarily serves other functional areas within the company, and not electric distribution.

TABLE 2B-1
ELECTRIC DISTRIBUTION WORKFORCE
(NUMBER OF EMPLOYEES)

Line No.	Job Grouping	2020	2021	2022	2023	2024	TYD 2025	Change Since 2020	Percent Change Since 2020
1	Associate Distribution Engineer	234	227	236	268	257	248	14	6%
2	Analysts/Specialists	1,056	1,201	947	1,337	1,289	1,386	330	31%
3	Apprentice	589	618	621	597	621	649	60	10%
4	Cable Splicer	52	47	47	44	50	52	0	0%
5	Clerical	788	771	785	783	789	737	(63)	(8)%
6	Coordinators	145	167	176	184	203	205	60	41%
7	Craft Worker	132	171	179	160	164	166	34	26%
8	Crew Leader	551	561	569	578	594	596	45	8%
9	Dispatcher	53	56	53	59	62	64	11	21%
10	Electric Line Assistant	19	37	39	69	78	66	47	247%
11	Electricians	269	257	260	265	269	270	1	0%
12	Engineer	746	839	871	949	980	986	240	32%
13	Equipment Operator	111	122	121	123	139	138	27	24%
14	Estimator	532	539	567	654	634	624	92	17%
15	Field Service Representative	–	–	–	–	–	–	N/A	N/A
16	Field Technician	391	424	331	408	380	371	(20)	(5)%
17	Inspectors	196	186	184	232	254	250	54	28%
18	Land and Environment	376	404	395	408	403	408	32	9%
19	Leadership	296	315	305	361	398	462	166	56%
20	Line Worker	572	558	666	737	794	797	225	39%
21	Materials Worker	1	1	1	2	1	1	0	0%
22	Mechanic	3	2	3	4	4	5	2	67%
23	New Business Representative	278	344	340	335	332	322	44	16%
24	Project Manager	227	265	219	210	221	265	38	17%
25	Safety and Security	18	19	14	15	19	21	3	17%
26	Scientists	61	63	61	61	65	67	6	10%
27	Service Representative	3	4	1	1	1	1	(2)	(67)%
28	Supervisor – Back Office	132	147	140	165	150	162	30	23%
29	Supervisor – Frontline	492	510	525	566	550	578	86	17%
30	System Operator	168	175	192	192	198	197	29	17%
31	Technician	130	140	136	131	127	121	(9)	(7)%
32	Troubleshooter	402	400	402	414	425	424	22	5%
33	Utility Worker	117	128	92	138	145	152	35	30%
34	Grand Total	9,140	9,713	9,424	10,403	10,555	10,799	1,639	18%

As described above, PG&E constructs, operates, and maintains the electric distribution system using a combination of internal and external labor—typically at a 60/40 splits. This ratio ensures PG&E's internal workforce is not idle during low-demand periods during a year. PG&E can scale contract resources as needed to meet seasonal or emergent demand.

While PG&E was not able to keep pace with customer energization requests beginning in 2022 (thus prompting the Powering Up Californians Act), the backlog of work is being primarily driven by funding constraints. For example, in 2022, the imputed adopted GRC funding for new business energization work (MWC 16) was $480 million, but PG&E incurred $817 million to keep up with demand as much as possible within the overall financial constraints of the

company. Contract labor resources can scale to complete the backlog of projects—a short-term surge in resources—however, the ability to finance and pay for these resources is limited.

For this reason, pursuant to Section 937 of the Powering Up Californians Act, PG&E requested additional funding for energization-related work, above the initial funding levels authorized in the 2023 GRC.[9] PG&E's request was adopted in Decision (D.) 24-07-008, which established a memorandum account with interim rate relief subject to an annual cap. Even this additional funding was insufficient to meet customer connection demand. Therefore, PG&E filed a subsequent motion requesting an increase to the annual caps based on forecasts that the energization demand and costs substantially exceed the annual caps.[10] As of May 1, 2025, this motion is still pending.

While insufficient funding is the primary reason PG&E has not been able to keep-up with demand, PG&E recognizes that additional qualified labor is needed to meet increased energization work, and set an internal goal to hire 100 lineworkers each year for the next 5 years to meet this demand. As PG&E works to meet all demand related to energization, continued focus on work related to wildfire, reliability, and other programs continue to be monitored and executed to ensure PG&E is meeting all requirements utilizing internal and external resources.

E. Future Staffing Analysis

The 2027 GRC presents PG&E's proposed risk-informed, multi-year Electric Distribution forecasts for work necessary to safely and reliably construct, operate, and maintain the electric distribution system. For purposes of analyzing future potential staffing needs, PG&E uses these forecasts as the basis for level of Electric Distribution work that will be required through 2030. Thus, the following analysis identifies the potential long-term staffing needs during this period. To the extent that authorized funding differs from PG&E's forecasts, the level of work required and the associated staffing needs will change.

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9 See D.24-07-008, p. 4.

10 PG&E Motion to Increase 2025 and 2026 Energization Cost Caps, (October 4, 2024). Rulemaking 24-01-018.

In this analysis, PG&E first determined the annual percentage of capital expenditures by MWC Groupings (Distribution Projects, Distribution Maintenance, Distribution Support Services, New Business, System Operations, Transmission & Substation, and Vegetation Management) (See Table 2B-2). The MWCs assigned to each MWC Grouping are provided in Appendix 2. This methodology provides granularity regarding the annual percentage changes in labor hours expected by job type based on the type and level of work forecast in the GRC. For example, total labor hours for Electric Distribution, year over year, will increase in 2025, 2027, and 2030 and decrease in 2026, 2028, and 2029 based upon PG&E's 2025-2030 Electric Distribution forecast. MWC Groupings align to the organizations accountable for managing budgets and headcount within Electric Distribution.

TABLE 2B-2
YEAR OVER YEAR FORECASTED SPEND CHANGE BY MWC GROUPING

Line No.		2025 FCST %	2026 FCST %	2027 FCST %	2028 FCST %	2029 FCST %	2030 FCST %
1	Distribution Projects & Hardening	33%	1%	(20)%	(28)%	(3)%	9%
2	Electric Dist Maintenance	3%	(7)%	134%	5%	5%	5%
3	Distribution Support Services	14%	(2)%	(29)%	(10)%	0%	21%
4	New Business*	(3)%	(20)%	117%	28%	(39)%	25%
5	System Operations & Inspections	(26)%	(3)%	14%	2%	2%	3%
6	Transmission & Substation	19%	20%	29%	8%	15%	7%
7	Veg Management	(14)%	(1)%	(15)%	1%	(1)%	(1)%
8	Grand Total	2%	(3)%	32%	(3)%	(7)%	10%

Note: New Business forecast uses the Alternative Forecast amounts presented in Exhibit (PG&E-4), Chapter 10, Section G.1, to capture the high-case scenario of potential work.

Next, PG&E identified recorded data for labor hours (standard and overtime) by job identification code charged to each MWC in the Electric Distribution portfolio in 2024. There are over 370 job identification codes relevant to Electric Distribution, so the codes were consolidated into 32 job groupings used at the enterprise-level for workforce planning. PG&E then scaled the labor hours for each job grouping corresponding to the annual forecast changes by the MWC groupings shown above in Table 2B-2.

The change in labor hours for each job grouping is then multiplied by 60 percent to maintain the internal/external labor ratio. Labor hours were then

converted to available hours to be charged to electric distribution work by applying a Productive Capacity Factor to assumed annual hours of 2,080 per employee. This accounts for the time not spent working directly on energization or other electric distribution work such as training, safety meetings, travel time, etc.. Table 2B-3 shows the results from this analysis: the annual incremental change in headcount by job grouping from 2025-2030 based on PG&E's Electric Distribution forecasts. Table 2B-4 shows the total incremental headcount for each job category by MWC Grouping.

TABLE 2B-3
CHANGE IN HEADCOUNT BY JOB GROUPING BASED ON 2027 GRC REQUEST

Line No.	Job Grouping	2025	2026	2027	2028	2029	2030	Net Total
1	Associate Distribution Engineer	5	(2)	28	(2)	0	5	34
2	Analysts/Specialists	(2)	(1)	29	(6)	(1)	20	39
3	Apprentice	1	(10)	137	21	(23)	32	158
4	Cable Splicer	1	(1)	10	2	(4)	3	11
5	Clerical	0	0	0	0	0	0	0
6	Coordinators	0	(3)	18	8	(14)	6	15
7	Craft Worker	0	1	6	1	1	2	11
8	Crew Leader	0	(3)	118	22	(12)	28	153
9	Dispatcher	(5)	0	2	0	0	1	(2)
10	Electric Line Assistant	(2)	(3)	25	5	(5)	5	25
11	Electricians	13	15	35	12	15	14	104
12	Engineer	35	14	64	5	16	36	170
13	Equipment Operator	4	(3)	27	2	(8)	7	29
14	Estimator	19	(8)	112	(5)	3	20	141
15	Field Technician	(16)	(1)	23	4	1	8	19
16	Inspectors	(14)	0	26	0	4	8	24
17	Land and Environment	13	(3)	12	(2)	(14)	13	19
18	Leadership	2	0	(2)	(2)	0	1	(1)
19	Line Worker	(9)	(27)	238	37	(52)	50	237
20	Materials Worker	0	0	0	0	0	0	0
21	Mechanic	0	0	1	0	0	0	1
22	New Business Representative	0	(3)	15	7	(15)	6	10
23	Project Manager	23	6	0	(13)	7	9	32
24	Safety and Security	0	0	0	0	0	0	0
25	Scientists	1	0	0	(1)	0	1	1
26	Service Representative	0	0	0	0	0	0	0
27	Supervisor- Back Office	1	0	(2)	(2)	0	1	(2)
28	Supervisor- Frontline	1	1	0	(1)	1	2	4
29	System Operator	(3)	(1)	21	3	(1)	5	24
30	Technician	4	(1)	1	0	(3)	6	7
31	Troubleshooter	(21)	(3)	23	4	(3)	6	6
32	Utility Worker	7	2	28	5	(1)	9	50
33	Grand Total	58	(34)	995	104	(108)	304	1,319

TABLE 2B-4
NET CHANGE IN HEADCOUNT BETWEEN 2026-2030
BY MWC GROUPING BASED ON 2027 GRC REQUEST

Line No.	Job Grouping	Distribution Projects & Hardening	Maintenance	Support Services	New Business	System Ops & Inspections	Transm & Subs.	Veg Mangt
1	Associate Distribution Engineers	(3)	37	0	2	(1)	1	0
2	Analysts/Specialists	(10)	39	(4)	7	(10)	29	(11)
3	Apprentice	(7)	113	0	29	(8)	31	0
4	Cable Splicer	(7)	6	0	4	0	2	0
5	Clerical	0	0	0	0	0	0	0
6	Coordinators	0	4	0	11	0	0	0
7	Craft Worker	0	4	0	1	(1)	7	0
8	Crew Leader	(5)	89	0	23	(8)	53	0
9	Dispatcher	0	0	0	0	(3)	0	0
10	Electric Line Assistant	(1)	21	0	5	(1)	0	0
11	Electricians	0	2	0	4	0	99	0
12	Engineer	(9)	54	(8)	10	(3)	127	0
13	Equipment Operator	(3)	25	0	7	(1)	1	0
14	Estimator	(12)	148	0	6	(3)	3	0
15	Field Technician	(1)	12	(1)	4	(10)	16	0
16	Inspectors	(3)	19	0	2	(11)	16	0
17	Land and Environment	(7)	10	(2)	12	(1)	8	(2)
18	Leadership	(1)	0	0	0	0	0	0
19	Line Worker	(11)	211	0	52	(14)	3	(1)
20	Materials Worker	0	0	0	0	0	0	0
21	Mechanic	0	0	0	0	0	2	0
22	New Business Representative	(1)	0	0	11	0	0	0
23	Project Manager	(10)	7	0	0	0	35	0
24	Safety and Security	0	0	0	0	0	0	0
25	Scientists	(1)	2	0	0	0	0	0
26	Service Representative	0	0	0	0	0	0	0
27	Supervisor- Back Office	(1)	0	0	0	0	0	0
28	Supervisor- Frontline	(1)	0	(1)	0	(1)	5	0
29	System Operator	(1)	16	0	3	(3)	9	0
30	Technician	(1)	7	(3)	3	0	2	0
31	Troubleshooter	(1)	12	0	4	(11)	2	0
32	Utility Worker	(2)	18	0	6	(1)	29	0
33	Grand Total	(99)	856	(19)	206	(91)	480	(14)

In years where the analysis shows a decrease in need for a particular job category, PG&E plans to hold headcount flat (i.e., PG&E does not plan to reduce the internal workforce for this reason). Instead, in these instances, PG&E reduces the amount of contract labor (i.e., PG&E would use fewer external workers). These annual variations in workforce needs illustrates one of the benefits of utilizing external contractors as part of the overall workforce strategy: contract labor allows PG&E to maintain a steady internal workforce. The net total headcount (2025-2030) represents the long-term incremental headcount need based on this 2027 GRC request.

Lastly, while this analysis is based on scaling labor based on the 2027 GRC cost forecasts, PG&E existing staffing plans warrant adjustments to the analysis

provided above. We plan to keep headcount steady for several job categories (analysts/specialists, leadership, safety/security, scientists, and supervisor-back office). With these adjustments, PG&E's future potential labor needs decrease, indicating an internal headcount increase of 1,282 employees compared to 2024 headcount levels. See Table 2B-5 below for details.

TABLE 2B-5
ADJUSTMENTS TO 2027 GRC REQUEST-BASED HEADCOUNT FORECAST

Line No.		2025	2026	2027	2028	2029	2030	Net Total
1	2027 GRC Forecast Headcount	58	(34)	995	104	(108)	304	1,319
2	Job Groupings that will not be Scaled	2	(1)	25	(11)	(1)	23	37
3	Adjusted Headcount	56	(33)	970	115	(107)	281	1,282

Note: This is the net of lines 2, 18, 24, 25, and 27 in Table 2B-3.

As described above, PG&E will use an "all of the above approach" (recruit, train, and retain) to increase its workforce to meet the level of work, tailored to the specific job position and region.

F. Apprentice Pipeline Analysis

A critical component of PG&E's staffing strategy is establishing an adequate pipeline of qualified labor to meet future staffing needs. Qualified labor, in this instance, refers to job positions that require completion of an apprenticeship or other formal training program, as required by CBAs. Formal apprenticeship programs have been created between PG&E and the IBEW for specific job positions that the Joint Apprenticeship Training Committee (JATC)[11] designated as warranting formal, multi-year training programs, including classroom and on-the-job training, given the safety risks and public impacts inherent in the work. The JATC seeks California state approval of the apprenticeship programs to certify that the programs meet the curriculum criteria established by the state. There are six job positions in PG&E's electric distribution portfolio requiring completion of a JATC-approved and state-approved apprenticeship: (1) lineworkers, (2) cable splicers, (3) electricians, (4) electric technicians,

[11] The Joint Apprentice Training Committee (JATC) is an eight-person committee with four members from IBEW and four members from PG&E. The terms of a specific apprenticeship are set forth in the Apprenticeship Administrative Manual.

(5) distribution system operators, and (6) metering system technicians. PG&E continuously works with IBEW to ensure the apprentice pipeline remains full and in compliance with the CBAs (and letter agreements) to accommodate future staffing needs.

PG&E and ESC also developed formal multi-year training programs for certain job positions. These training programs are designed by the Joint Training Committee (JTC).[12] To date, there are three job categories with formal training programs: (1) estimators, (2) new business representatives, and (3) mapping technicians. These training programs do not have Job Training Ratios that restrict the volume of potential trainees, and therefore a pipeline analysis was not completed.

1. Lineworker Apprentice Program

The Linework Apprentice Program consists of 8 six-month modules, totaling four years. The CBA includes a multi-prong Training Labor Ratio. In the first two years of on-the-job training, Line Worker Apprentices are not allowed to work on electrified wires (Cold Apprenticeship) given the safety risks associated with live wires. However, once the apprentice has successfully completed the first two years of training, they will have sufficient training to begin working on electrified lines. As a result, in the remaining two years (Years 3 and 4) of on-the-job training, Line Worker Apprentices can work on electrified wires (Hot Apprenticeship). The current CBA requires that for every Cold Apprentice on a crew, there must be at least one journey worker. However, a crew can have two Hot Apprentices per journey worker.

PG&E tracks and monitors Lineworker addition and attrition to ensure there are a sufficient amount of qualified electrical workers able to support work demands related to energization. Consistent with the 2023 GRC and Section 5.6.1 of the 2020 GRC Settlement Agreement, PG&E keeps the Apprentice Lineman Training Program filled to the maximum extent, consistent with safe crew staffing ratios. The program provides a skilled and qualified workforce to maintain electric system reliability and provide safe

[12] The JTC is an eight-person committee with four members from ESC and four members from PG&E. The terms of each training program are set forth in an Administrative Manual.

service to customers. PG&E commits to continue this agreement through the 2027 GRC cycle. For additional information on PG&E's apprenticeship programs, see Exhibit (PG&E-7), Chapter 1.

PG&E's forecast of future staffing needs presented in Section E indicates that to scale PG&E's workforce based on forecasted work, PG&E must increase the number of lineworkers in the apprentice program by 262 positions between 2025-2030. Based on PG&E's existing workforce, there is a sufficient level of journey workers to meet the linework Training Program Ratios for Hot and Cold Apprentices, as there are currently two journey lineworkers per apprentice. Lineman journey workers include all job positions in the line of progression from the lineman apprentice. This means PG&E can continue to scale its apprentice pipeline based on the current percentage of journey worker linemen in the workforce (62 percent). Using these assumptions, PG&E would need 644 apprentice lineworkers in the training pipeline by 2030 to sustain future workforce needs, accounting for 493 current apprentices as of March 2025 and then adding 151 positions by 2030.

TABLE 2B-6
LINEWORKER APPRENTICE PIPELINE ANALYSIS

Line No.	Lineworkers	YTD Actuals	Percent of total FTE's	Increase	2030 Total Fcst
1	Apprentice	493	38%	151	644
2	Journey[(a)]	800	62%	245	1,045
3	Total	1,293	100%	396	1,689
4	Ratio	2:1			2:1

(a) Includes all journey workers in the line of progression that have completed the lineworker apprenticeship.

2. Cable Splicer Apprenticeship

Cable splicers are trained to connect and repair electric wires to other wires, transformers, junction boxes, and other equipment in predominantly PG&E's networked underground systems, but may also perform these activities for overhead systems or stations. This training requires

7 six-month modules, totaling 3.5 years. The CBA requires a 1:1 apprentice cable splicer to journey worker cable splicer Training Labor Ratio.

PG&E's future staffing needs forecast in Section E indicates that to scale PG&E's workforce based on forecasted work, PG&E must increase the number of cable splicers in the apprenticeship program by 2 positions between 2025-2030. Based on PG&E's existing workforce, there is overall sufficient journey workers to meet the cable splicer Training Program Ratio, as there are currently 6 cable splicer journey workers per apprentice. This means PG&E can continue to scale its apprentice pipeline based on the current percentage of journey worker cable splicers in the workforce (85 percent). Using these assumptions, PG&E would need 11 apprentice cable splicers in the training pipeline by 2030 to sustain future workforce needs, accounting for 9 current apprentices as of March 2025 and then adding 2 positions by 2030.

TABLE 2B-7
CABLE SPLICER APPRENTICE PIPELINE ANALYSIS

Line No.	Cable Splicers	YTD Actuals	Percent of total FTE's	Increase	2030 Total Fcst
1	Apprentice	9	15%	2	11
2	Journey[(a)]	52	85%	9	61
3	Total	61	100%	11	72
4	Ratio	6:1			6:1

(a) Includes all journey workers in the line of progression that have completed the cable splicer apprenticeship.

This pipeline analysis focuses solely on staffing needs based on the forecast of future work proposed in the 2027 GRC. PG&E also has a letter agreement with IBEW to commit to fill no less than six Apprentice Cable Splicer positions in 2025, and if specific training curriculums are completed by late 2025, to also fill no less than six positions in 2026 and 2027.

3. Electrician Apprenticeships

Electricians have the skills and training necessary to inspect and maintain electrical equipment including but not limited to, power transformers, instrument and control transformers, circuit breakers,

disconnect switches, relays, and ancillary control systems. This training requires 8 six-month modules, totaling 4 years. The CBA requires a 1:1 apprentice electrician to journey worker Training Labor Ratio.

PG&E's future staffing needs forecast in Section E indicates that to scale PG&E's workforce based on forecasted work, PG&E must increase the number of electricians in the apprenticeship program by 20 positions between 2025-2030. Based on PG&E's existing workforce, there is overall sufficient journey workers to meet the electrician Training Program Ratio, as there are currently 4 electrician journey workers per apprentice. This means PG&E can continue to scale its apprentice pipeline based on the current percentage of journey worker electricians in the workforce (81 percent). Using these assumptions, PG&E would need 84 apprentice electricians in the training pipeline by 2030 to sustain future workforce needs, accounting for 64 current apprentices as of March 2025 and then adding 20 positions by 2030.

TABLE 2B-8
ELECTRICIAN APPRENTICE PIPELINE ANALYSIS

Line No.	Electric	YTD Actuals	Percent of total FTE's	Increase	2030 Total Fcst
1	Apprentice	64	19%	20	84
2	Journey[(a)]	270	81%	84	354
3	Total	334	100%	104	438
4	Ratio	4:1			4:1

(a) Includes all journey workers in the line of progression that have completed the electrician apprenticeship.

4. Electric Technician Apprenticeship

Electric technicians are responsible for performing work involving an extremely high degree of complexity, including troubleshooting, repairing, calibrating, and maintaining components of protective relay systems; substation and electric utility protection systems; station automation and supervisory control and data acquisition (SCADA) systems. Electric Technicians must first complete the Electrician Apprenticeship. Thereafter, the coworker is eligible to complete the Electric Technician Apprenticeship

The Electric Technician apprenticeship is 5 six-month modules, totaling 2.5 years. The CBA also requires a 1:1 apprentice electrician tech to journey worker Training Labor Ratio.

PG&E's future staffing needs forecast in Section E indicates that to scale PG&E's workforce based on forecasted work, PG&E must increase the number of Electric Technicians in the apprenticeship program by two positions between 2025-2030. Based on PG&E's existing workforce, there is overall sufficient journey workers to meet the electric technician Training Program Ratio, as there are currently 3 electrician journey workers per apprentice. This means PG&E can continue to scale its apprentice pipeline based on the current percentage of journey worker electric technicians in the workforce (73 percent). Using these assumptions, PG&E would need 24 apprentice electric technicians in the training pipeline by 2030 to sustain future workforce needs, accounting for 22 current apprentices as of March 2025 and then adding 2 positions by 2030.

TABLE 2B-9
ELECTRIC TECHNICIAN APPRENTICE PIPELINE ANALYSIS

Line No.	Electric Technicians	YTD Actuals	Percent of total FTE's	Increase	2030 Total Fcst
1	Apprentice	22	27%	2	24
2	Journey[(a)]	59	73%	5	64
3	Total	81	100%	7	88
4	Ratio	3:1			3:1

(a) Includes all journey workers in the line of progression that have completed the electric technician apprenticeship.

5. Distribution System Operator Apprenticeship

Distribution system operators are responsible for monitoring and controlling the distribution system, including shifting loads to accommodate maintenance work or respond to emergencies, issue clearances, and promptly restore service. This training requires 5 six-month modules, totaling 2.5 years. The CBA requires a 1:1 apprentice distribution system operator to distribution system operator Training Labor Ratio, until an apprentice has the proficiency to perform duties without supervision.

PG&E's future staffing needs forecast in Section E indicates that to scale PG&E's workforce based on forecasted work, PG&E must increase the number of distribution system operators in the apprenticeship program by 4 positions between 2025-2030. Based on PG&E's existing workforce, there is overall sufficient system operators to meet the Training Program Ratio, as there are currently 6 distribution system operator journey workers per apprentice. This means PG&E can continue to scale its apprentice pipeline based on the current percentage of journey workers in the workforce (85 percent). Using these assumptions, PG&E would need 40 apprentice Distribution System Operators in the training pipeline by 2030 to sustain future workforce needs, accounting for 36 current apprentices as of March 2025 and then adding 4 positions by 2030.

TABLE 2B-10
DISTRIBUTION SYSTEM OPERATOR APPRENTICE PIPELINE ANALYSIS

Line No.	System Operators	YTD Actuals	Percent of total FTE's	Increase	2030 Total Fcst
1	Apprentice	36	15%	4	40
2	Journey[(a)]	199	85%	20	219
3	Total	235	100%	24	259
4	Ratio	6:1			6:1

(a) Includes all journey workers in the line of progression that have completed metering system technician apprenticeship.

6. Metering System Technician Apprenticeship

Metering System Technicians install, program, test, calibrate, troubleshoot, and repair all types of electric/electronic circuits, components and devices related to billing measurement. This training includes 6 six-month modules, totaling 3 years. The CBA does not require a specific Training Labor Ratio, as apprentices may work alone or under indirect supervision on jobs for which the employee has been trained and instructed.

PG&E's future staffing needs forecast in Section E indicates that to scale PG&E's workforce based on forecasted work, PG&E must increase the number of Metering System Technicians in the apprenticeship program by 1 position between 2025-2030. Since there is no Training Program Ratio

for this apprenticeship, PG&E can continue to scale its apprentice pipeline based on the current percentage of journey workers in the workforce (91 percent). Using these assumptions, PG&E would need 26 apprentice Metering System Technicians in the training pipeline by 2030 to sustain future workforce needs, accounting for 25 current apprentices as of March 2025 and then adding 1 position by 2030.

TABLE 2B-11
METERING SYSTEM TECHNICIAN APPRENTICE PIPELINE ANALYSIS

Line No.	Metering System Tech.	YTD Actuals	Percent of total FTE's	Increase	2030 Total Fcst
1	Apprentice	25	9%	1	26
2	Journey[(a)]	261	91%	11	272
3	Total	286	100%	12	298
4	Ratio	10:1			10:1

(a) Includes all journey workers in the line of progression that have completed metering system technician apprenticeship.

G. Conclusion

Regardless of the ultimate volume and type of work that is approved in the 2027 GRC, PG&E expects continued demand for electric distribution work and a need to increase its staffing levels, including apprenticeships. The order of magnitude for increasing certain job types will be determined at the appropriate time taking into consideration local work demand, local staffing levels, and financial investment plans.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT B

APPENDIX 1

JOB TITLES BY JOB GROUPING

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ATTACHMENT B
APPENDIX 1
JOB TITLES BY JOB GROUPING

Associate Distribution Engineers

Assoc Disbn Engineer Local Electric
Assoc Disbn Engineer Local Gas
Assoc Dsbn Engr - Elec - Provisional
Assoc Dsbn Engr - Gas - Provisional
Associate Distribution Engineer - Elec
Associate Distribution Engineer - Gas

Analysts/Specialists

(Nuc) Procurement Specialist - ESC
(Nuc) Procurement Specialist - ESC, Sr
(Nuc) Procurement Specialist, Sr. Adv
(Nuc) Procuremnt Tech Speclst, Sr Advsng
Asset & Maintenance Planner
Asset & Maintenance Planner, Senior
Asset Management Specialist, Principal
ATS Technical Specialist, Expert
ATS Technical Specialist, Senior
Aviation Operations Specialist, Expert
Aviation Operations Specialist, Senior
Business Analyst
Business Analyst, Expert
Business Analyst, Principal
Business Analyst, Senior
Business Operations Specialist, Expert
Business Performance Analyst, Expert
Business Performance Analyst, Senior
Business Process Analyst
Business Process Analyst, Expert
Business System Specialist
Business System Specialist, Associate
Business System Specialist, Expert
Business System Specialist, Senior
Category Leader, Expert
Category Leader, Principal
Category Leader, Senior
Compliance & Risk Consultant
Compliance & Risk Consultant, Expert
Compliance & Risk Consultant, Principal
Compliance & Risk Consultant, Senior
Compliance Data Analyst, Expert
Construction Manager
Construction Manager, Expert
Construction Manager, Principal
Construction Manager, Senior
Contract Lifecycle Manager
Contract Lifecycle Manager, Senior
Contract Pricing Analyst, Expert
Contract Specialist
Contract Specialist, Expert
Contract Specialist, Senior
Corrosion Specialist, Expert
CRE Business Partner, Principal
CRE Program Manager, Principal
Cultural Resource Specialist
Cultural Resource Specialist, Senior
Cultural Resource Speclst,Sr Cnsltng-ESC
Cust Care Information Sys Analyst, Prn
Cust Care Operations Specialist
Cust Care Operations Specialist, Senior
Data Engineer, Expert
Data Scientist, Senior
Data Steward
Database Analyst, Expert
DCPP HH Procurement Specialist
Distrib Training & Simulation Spec, Sr
EGI Account Representative - ESC
EGI Business Analyst - ESC, Sr
EGI Contract Manager - ESC
EGI Interconnection Manager - ESC, Asc
Electric Compliance Specialist, Expert
Electric Compliance Specialist, Prn
Electric Construction Specialist, Expert
Electric Construction Specialist, Senior
Electric Program Manager, Expert
Electric Program Manager, Principal
Electric Program Manager, Senior
Electric Quality Control Specialist, Exp
Electric Quality Control Specialist, Sr
Energy Diversion Investigator
Energy Diversion Specialist
Energy Mgmt System Specialist
Facilities Planner, Senior
Facilities Program Manager, Principal
Fleet IS Specialist, Senior
FMO Resource Analyst, Expert
Gas Program Manager, Principal

GIS Analyst
GIS Analyst, Senior
HH EGI Account Representative - ESC
HH EGI Interconnection Mgr - ESC
HH EGI Interconnection Mgr - ESC, Asc
HH EGI Interconnection Mgr - ESC, Sr
Hiring Hall Scheduler in Training - ESC
Inspection Review Specialist, Expert
Inspection Review Specialist, Senior
Insulation Tester
Intern
Investment Recovery Specialist, Expert
Investment Recovery Specialist, Senior
ISO/FERC Regulatory Analyst, Principal
Land Planning Analyst - ESC
Lean Specialist, Expert
Metering Project Specialist, Expert
Metering Project Specialist, Senior
Not assigned
Operations Data Analyst, Expert
Operations Data Analyst, Principal
Operations Data Analyst, Senior
Operations Performance Manager
Operations Performance Manager, Expert
Operations Performance Manager, Prn
Operations Performance Manager, Senior
Permit Facilitator, Career - ESC
PIO Information Systems Analyst, Sr-ESC
Product Manager
Product Manager, Principal
Product Manager, Senior
Product Owner, Principal
Program Manager
Program Manager, Expert
Program Manager, Principal
Program Manager, Senior
Project Architect-GOLD CIRCLE
Project Management Anlst-Env-ESC, Sr
Project Surveyor
Protection Specialist, Expert
Protection Specialist, Principal
Quality & Improvement Specialist
Quality and Improvement Specialist, Sr
Quality Assurance Auditor, Exp
Quality Assurance Auditor, Sr
Real Estate Technical Specialist II
Real Estate Transaction Specialist, Exp
Regulatory Analyst
Regulatory Analyst, Expert
Regulatory Analyst, Principal
Regulatory Analyst, Senior
Rental and Pool Administrator, Senior
Risk & Compliance Analyst, Expert
Rotational Development Program Trainee
Safety Program Manager, Principal
Safety Specialist, Expert
SCADA Specialist
SCADA Specialist, Expert
SCADA Specialist, Senior
Scheduler - ESC
Scheduler in Training - ESC
Senior Land Technical Specialist
Service Solutions Specialist, Senior
Site Operations Manager, Principal
Site Operations Manager, Senior
Sr Mapping Tech-Elec Pass Expert Test
Strategic Analyst
Strategic Analyst, Expert
Strategic Analyst, Principal
Substation Test Specialist
Substation Test Specialist, Assoc
Substation Test Specialist, Senior
Supervisor, Vegetation Management Ops
Supplier Responsibility, Expert
Supplier Responsiblity, Principal
Supply Chain Program Consultant, Expert
Supply Chain Program Consultant, Senior
Technical Assistant, Specialist
Technical Remediation Cslt, Principal
Technical Specialist I
Technical Specialist II
Technical Writer, Expert
Training & Simulation Specialist, Expert
Training & Simulation Specialist, Senior
Transmission Planning Eng,Sr Advsng-ESC
Transmission Training Specialist, Prn
Vegetation Program Manager
Vegetation Program Manager, Senior
Work & Resource Analyst, Principal
Work & Resource Analyst, Senior
Work Methods & Procedures Speclst, Exp
Work Plan Portfolio Specialist, Prn
Workstream Program Specialist, Expert
Workstream Program Specialist, Senior

Apprentice

Appr Cable Splicer Hired after 1-1-15
Appr Cable Splicer-GC Hired after 1-1-15
Apprentice Electrical Technician
Apprentice Electrical Technician - GC
Apprentice Electrician - GC
Apprentice Electrician-Electric & Hydro
Apprentice Line Worker
Apprentice Line Worker - GC
Apprentice Line Worker - Transmission
Apprentice Metering System Technician
Apprentice System Operator

Cable Splicer

Cable Splicer
Cable Splicer - GC
Cable Splicer - GC - SF/PN/DA/SJ
Cable Splicer - SF/PN/DA/SJ
Night Cable Splicer - SF/PN/DA/SJ
Transmission Underground Troubleshooter
Unassigned Cable Splicer
Unassigned Cable Splicer - SF/PN/DA/SJ

Clerical

Accounting Clerk
Administrative Clerk, Senior
Director's Assistant
First Field Clerk
Hiring Hall Operating Clerk - Exper
Hiring Hall Operating Clerk - Inexp
Hiring Hall Reprographics Opr B - Inexp
Hiring Hall Routine Field Clerk - Inexp
Operating Clerk
Operating Clerk-Typist
Parts Clerk
Reprographics Oper (1/1/2023 and After)
Reprographics Oper (Before 1/1/2023)
Routine Field Clerk
Senior Accounting Clerk I
Senior Operating Clerk I
Senior Operating Clerk I-II

Coordinators

M&C Coordinator - Electric
M&C Coordinator - Electric - SF/PN/DA/SJ
M&C Coordinator - Electric Transmission
M&C Coordinator - ElecTrnsmn-SF/PN/DA/SJ
New Business Liaison-Elec Crew Fmn(PIO)
New Business Liaison-Electric
New Business Liaison-Lineworker (PIO)
Transmission Outage Coordinator

Craft Worker

AWS Certified Welder
Building Technician
Certified Welder
Critical Facilities Lead
Critical Facility Technician
Fieldperson - Tower
HH Night Electric T&D Assist - Inexp
Hiring Hall Machinist-Experienced
Hiring Hall Painter B - Inexperienced
Lead Carpenter
Lead Driver
Machine Shop Leader
Machinist
Night Electric Transm & Dsbn Assistant
Painter - Materials Distribution
Painter A - GC Field
Painter B - GC Field
Painter-Utility Worker
PIO Electric Transm & Dsbn Assistant
Street Light Maintenance Person (PIO)
Towerperson
Truck Driver Light - Materials

Crew Leader

Building Crew Leader
Cable Crew Leader
Cable Crew Leader - SF/PN/DA/SJ
Electric Crew Leader
Electric Crew Leader - SF/PN/DA/SJ
Electric Crew Leader - Transmission
Electric Crew Leader, Service
Electric Crew Leader-Trnsmn-SF/PN/DA/SJ
Electric Maintenance Crew Leader
Garage Crew Lead
Garage Crew Lead - DCPP
Garage Working Leader
GC Crew Lead A - GC Station
GC Crew Lead A - Overhead
GC Crew Lead A - Underground
GC Crew Lead B
GC Crew Lead B I&C
GC Crew Leader A - Overhead-SF/PN/DA/SJ
GC Crew Leader A - UG - SF/PN/DA/SJ
Lead Electrical Technician
Materials Handler -Hired before 2009
Metering Technician Crew Leader
Night Cable Crew Leader
Night Cable Crew Leader - SF/PN/DA/SJ
Underground Constr Crew Leader-Electric
Working Leader (PIO)
Working Leader A - Non-Climbing
Working Leader B - GC Station
Working Leader B I&C (Non-Climbing)
Working Leader B-Crane Surveyor
Working Leader C
Working Leader D
Working Leader-Gas GC

Dispatcher

Sr. System Dispatcher (PIO)
System Dispatcher
System Dispatcher (PIO)
W&R Dispatcher - Electric
W&R Dispatcher - Metering
W&R Dispatcher in Training - Metering
W&R Dispatcher-in-Training - Electric
W&R Relief Dispatcher - Electric
W&R Relief Dispatcher Metering

Electric Line Assistant

Electric Line Assistant-Electric T&D
HH Electric Line Assistant - Inexp

Electricians

Electric Shop Leader
Electrician
Electrician - Electric & Hydro
Electrician - GC
Electrician - Switching
Hiring Hall Electrician - Exper
Traveling Electric Shop Leader
Unassigned Electrician - Elec & Hydro

Engineer

ATS Engineer
ATS Engineer, Associate
ATS Engineer, Expert
ATS Engineer, Principal
ATS Engineer, Senior
Automation Engineer, Principal-ESC
Automation Engineer, Senior Advising-ESC
Automation Engineer, Senior-ESC
Automation Engineer, Sr Consulting-ESC
Automation Engineer-ESC
Civil Engineer, Principal
Civil Engineer-Prj Engg
Civil Engineer-Prj Engg, Senior
Civil Engineer-Prj Engg, Sr-GOLD CIRCLE
Civil Engineer-Prj Engg-GOLD CIRCLE
Civil Engr-Prj Engg, Sr Cnsltng-GOLD CIR
Corrosion Engineer
Corrosion Engineer, Expert
Corrosion Engineer, Principal
Design Drafter
Design Engineer
Drafter
EGI Interconnection Manager - ESC
EGI Interconnection Manager - ESC, Sr
Elec Distribution Ops Engineer
Elec Distribution Ops Engineer, Asc
Elec Distribution Ops Engineer, Senior
Elec Distribution Ops Engineer-GOLD CIR
Elec Distributn Ops Engr,Senior-GOLD CIR
Elec Stds and Strategy Engineer

Elec Stds and Strategy Engineer, Asc
Elec Stds and Strategy Engineer, Sr
Elec Stds and Strategy Engr, Sr. Adv
Elec Stds and Strategy Engr, Sr. Cnslt
Elec Stds and Strgy Eng, SrAdv-GLD CIR
Elec Stds and Strgy Eng, SrCnslt-GLD CIR
Elec Stds and Strgy Engr, Sr-GOLD CIR
Electrcl Engr-Prj Engg,Sr Cnsltng-GLDCIR
Electric Distribution Engineer
Electric Distribution Engineer, Asc
Electric Distribution Engineer, Senior
Electric Distribution Engineer, Sr Clt
Electric Distribution Engineer, Sr. Adv
Electric Distribution Engineer-GOLD CIR
Electric Engineer, Principal
Electrical Engr-Prj Engg, Sr
Electrical Engr-Prj Engg, Sr Cnsltng
EMS Operations Systems Engineer
EMS Operations Systems Engineer, Assoc
EMS Operations Systems Engineer, Senior
EMS Operations Systems Engineer, Sr Adv
EMS Ops Systems Integ Engineer
EMS Ops Systems Integ Engineer, Sr
EMS SCADA Engineer
EMS SCADA Engineer, Senior
Engineering Assistant I
Engineering Assistant II
Engineer-Prj Engg, Asc
Field Engineer - ESC
Field Engineering Technician
Fleet Analyst, Senior
Fleet Engineer
Fleet Engineer, Expert
Fleet Engineer, Senior
Gas Transmission Engineer, Expert
GIS Application Engineer
Grid Innovation Engineer
Grid Innovation Engineer, Expert
Grid Innovation Engineer, Principal
Grid Innovation Engineer, Senior
Hiring Hall Design Drafter
Hiring Hall Field Engineer - ESC
Industrial Power Engineer
Maintenance & Constr Engr
Maintenance & Constr Engr, Sr
Maintnce & Constr Engr, Sr-GOLD CIR
Maintnce & Constr Engr,Sr Advsng-GLD CIR
Maintnce & Constr Engr-GOLD CIRCLE
Operations Systems Engineer
Operations Systems Engineer, Associate
Operations Systems Engineer, Expert
Operations Systems Engineer, Principal
Operations Systems Engineer, Senior
Power Quality Engineer, Associate-ESC
Power Quality Engineer, Senior-ESC
Power Quality Engineer-ESC
Power Quality Engr, Sr Consulting-ESC
Protection Engineer
Protection Engineer - GOLD CIRCLE
Protection Engineer, Asc
Protection Engineer, Sr
Protection Engineer, Sr - GOLD CIRCLE
Protection Engineer, Sr Cnsltng
Protection Engr, Sr Cnsltng-GOLD CIRCLE
RAS Operations Engineer
RAS Operations Engineer, Associate
RAS Operations Engineer, Expert
RAS Operations Engineer, Senior
RAS Operations Engineer, Senior Advising
Senior Design Drafter
Senior Design Engineer
Senior Engineering Assistant
Senior Field Engineering Technician
Sr Engg Est Permit Facilitator - E (PIO)
Substation Engineer-Prj Engg
Substation Engineer-Prj Engg, Asc
Substation Engineer-Prj Engg, Sr
Substation Engineer-Prj Engg-GOLD CIRCLE
Substation Engr-Prj Engg, Sr-GOLD CIR
Supervisor, Operations Systems
System Protection Engr, Expert (500kv)
System Protection Engr, Principal
Transm Line Engineer-Prj Engg
Transm Line Engineer-Prj Engg, Asc
Transm Line Engineer-Prj Engg, Sr
Transm Line Engineer-Prj Engg-GOLD CIR
Transm Line Engr-Prj Engg, Sr-GOLD CIR
Transmission Operations Engineer - ESC
Transmission Ops Engineer, Asc - ESC
Transmission Ops Engineer, Sr - ESC
Transmission Ops Engineer, Sr Adv - ESC
Transmission Ops Engineer, Sr Cslt - ESC
Transmission Planning Engineer, Asc-ESC
Transmission Planning Engineer, Sr-ESC
Transmission Planning Engineer-ESC
Transmission Planning Engr, Sr Cslt-ESC

Equipment Operator

Backhoe Operator - Gas
Construction Operator-GC Gas
Crane Operator - GC Field-Not Gas
Miscellaneous Equipment Operator-Not Gas
Senior Construction Operator-GC Gas
Tractor Operator-Not Gas
Transm & Dsbn Equipment Opr - Transm
Transmission & Distribution Equip Opr

Estimator

Engineering Estimator - E, Local
Engineering Estimator - Electric
Engineering Estimator - Gas
Hiring Hall Engg Estimator - Electric
Hiring Hall Engineer Estimator - Elec
Hiring Hall Senior Eng Estimator-E,Local
Senior Engineering Estimator - Electric
Senior Engineering Estimator - Gas
Senior Engineering Estimator ADE - Elec
Senior Engineering Estimator ADE - Gas
Senior Engineering Estimator-E, Local
Senior Engineering Estimator-E, Local PT
Senior Engineering Estimator-G, Local

Field Technician

Distribution Line Technician
Distribution Line Technician-SF/PN/DA/SJ
Electrical Technician
Electrical Technician - GC
HH Routine Meter Person - Experience
Hiring Hall Installer Meter Reader-Exper
Hiring Hall Installer Meter Reader-Inexp
Lead Electrical Technician-GC
Meter Maintenance Person
Metering Electronics Technician
Metering Systems Technician
PIO Electric Field Meterperson
PIO Lead Electrical Technician
PIO Routine Meter Person
PIO Unassigned Electrical Technician
Unassigned Electrical Technician
Unassigned Metering Systems Technician

Inspectors

Civil Construction Inspector
Compliance Inspector
Compliance Inspector - SF/PN/DA/SJ
Compliance Inspector UG - SF/PN/DA/SJ
Construction Inspector
Crane Surveyor
Crane Surveyor in Training
HH Line Construction Inspector - GC
Hiring Hall Compliance Inspector
Lead Contractor Inspector - GC
Lead Contractor Inspector-GC-SF/PN/DA/SJ
Lead Inspector
Lead Pipeline Inspector-CWI
Mechanical Inspector
Not assigned
PIO Inspector
Pipeline Inspector CWI
Pre-Utility Inspector
Transmission Construction Inspector, Sr
Utility Construction Inspector
Utility Inspector-Underground
Vegetation Operations Inspector

Land and Environment

Chief of Party
Consulting Environmental Field Spec, Sr
Environmental and Safety Compliance, Exp
Environmental Field Specialist
Environmental Field Specialist, Senior
Environmental Policy Specialist, Expert
Environmental Policy Specialist, Prn
HH Environmental Fld Specialist, Sr-Exp
Land Agent
Land Agent, Principal
Land Consultant - Surveying, Expert
Land Consultant-EP&P, Principal
Land Consultant-Land Acquisition, Expert
Land Consultant-Land Acquisition, Prn
Land Consultant-Land Acquisition, Senior
Land Consultant-Property Management
Land Consultant-Property Management, Prn
Land Consultant-Property Mgmt, Expert
Land Consultant-Property Mgmt, Sr
Land Planner

Land Planner, Principal
Land Planner, Senior
Land Surveyor, Principal
Land Surveyor, Senior
Land Technician
Lead Land Technician

Leadership

Dir, Vegetation Mgmt Quality Control
Director, Applied Technology Services
Director, Compliance
Director, Electric Engineering Services
Director, Electric Program Management
Director, Performance Improvement
Director, Service Planning & Design
Director, Transmission Grid Operations
Director, Transmission Ops Support
Manager, ADMS
Manager, Applied Technology Services
Manager, ATS Quality and Improvement
Manager, Business Analysis
Manager, Construction Management
Manager, Elec. Transmission Planning
Manager, Electric Compliance
Manager, Electric Distribution Planning
Manager, Electric Program Management
Manager, Electric Project Management
Manager, Environmental
Manager, Environmental Programs
Manager, Facilities
Manager, Government Relations
Manager, Grid Innovation Engineering
Manager, Grid Operations
Manager, Maintenance & Construction
Manager, Materials
Manager, Nuclear Supply Chain
Manager, Operations Systems
Manager, Product Management
Manager, Regional Fleet Operations
Manager, Remediation
Principal Right-of-Way Agent
Right of Way Agent
Senior Land Agent
Senior Land Technician
Senior Right of Way Agent
Traffic Control Design Specialist
Manager, Sourcing Portfolio
Manager, Substation Design & Technology
Manager, Supplier Diversity
Manager, System Protection Engineering
Manager, Transmission Training
Manager, Vegetation Management Ops
Mgr, Elec. Trans Asset Development
Mgr, Strategy, Innovatn and Partnership
Program Manager, Chief
Senior Director, Corporate Real Estate
Senior Manager, Business Finance
Senior Manager, Business Systems
Senior Manager, Corporate Sustainability
Senior Manager, CRE Program Management
Senior Manager, Operations Systems
Senior Manager, Remediation
Senior Manager, Sourcing Portfolio
Sr Dir, Cust Experience & Reg Strategy
Sr Dir, Electric Engineering Services
Sr Manager, Applied Technology Services
Sr Manager, Electric Compliance
Sr Manager, Electric Program Management
Sr Manager, Grid Innovation Engineering
Sr Manager, LCE Planning and Operations
Sr Manager, Product Management
Sr Manager, Regulatory Proceedings
Sr Mgr, Elec. Transmission Planning
Sr Mgr, Electric Project Management
Sr Mgr, Strat, Innovatn and Partnershp
Sr Mgr, Substation Automation & SCADA
Strategic Analyst, Chief

Line Worker

Hiring Hall Line Worker - Division
Hiring Hall Line Worker Rubber Glov-Div
Line Worker
Line Worker - GC
Line Worker - GC - SF/PN/DA/SJ
Line Worker - SF/PN/DA/SJ
Line Worker - Transmission
Line Worker - Transmission - SF/PN/DA/SJ
Line Worker, Service
Not assigned
Unassigned Line Worker
Unassigned Line Worker - SF/PN/DA/SJ

Materials Worker

HH Materials Handler 2009 or Later-Exp
HH Materials Handler 2009 or Later-Inexp
Hiring Hall Materials Handler - GC - Exp
Hiring Hall Materials Handler - GC - Inx
Materials Distribution Flow Coord, Sr
Materials Handler - GC
Materials Handler - Hired 2009 or Later
Materials Leadperson
Outage Materials Handler

Mechanic

Building Mechanic
Equipment Mechanic
Equipment Mechanic - DCPP
Equipment Mechanic - GC
Field Garage Mechanic A
Field Garage Mechanic B
Lead Building Mechanic
Station Mechanic
Station Mechanic (PIO)
Utility Equipment Mechanic - Helms

New Business Representative

HH New Business Representative
Hiring Hall Senior New Business Rep
New Business Representative
Not assigned
Senior New Business Representative

Project Manager

Business Project Manager, Expert
Business Project Manager, Principal
Consulting Remediation Prject Manager-ES
HH Project Manager, Sr-ESC
IT Project Manager, Expert
IT Project Manager, Senior
Product Manager, Expert
Proj Mgr BSEngr-ESC, Sr Cnsltng-GOLD CIR
Project Controls Analyst, Expert - ESC
Project Controls Analyst-ESC
Project Controls Analyst-ESC, Sr
Project Manager BSEngr-ESC - GOLD CIR
Project Manager BSEngr-ESC, Asc-GOLD CIR
Project Manager BSEngr-ESC, Sr-GOLD CIR
Project Manager ESC, Asc -GOLD CIRCLE
Project Manager ESC, Sr-GOLD CIRCLE
Project Manager ESC-GOLD CIRCLE
Project Manager, Asc-ESC
Project Manager, Sr-ESC
Project Manager-ESC
Project Mgr ESC, Sr Cnsltng-GOLD CIRCLE
Remediation Project Manager-ESC
Remediation Project Manager-ESC, Senior
Technical Project Manager, Expert
Technical Project Manager, Senior

Safety and Security

Field Safety Specialist, Expert

Scientists

Aquatic Biologist, Senior - ESC
Chemist, Expert
Chemist, Senior
Consulting Scientist-ESC, Sr
Environmental Scientist - ESC
Environmental Scientist, Senior - ESC
Environmental Scientist, Sr Cnsltng -ESC
Terrestrial Biologist - ESC
Terrestrial Biologist, Senior - ESC

Service Representative

Senior Service Representative 2

Supervisor- Back Office

Supervisor, Area Fleet Operations
Supervisor, Business Analysis
Supervisor, Dispatch & Scheduling
Supervisor, Elec. Distribution Planning
Supervisor, Elec. Transmission Planning
Supervisor, Electric Compliance
Supervisor, Electric Program Management
Supervisor, Electric Project Management
Supervisor, Fleet Engineering
Supervisor, Operations Support
Supervisor, Performance Improvement
Supervisor, Property Management
Supervisor, Support Services
Supv, Investment Recovery Specialist

Supervisor – Frontline

Supervisor, Applied Technology Services
Supervisor, Automation Engineering
Supervisor, Construction
Supervisor, Corrosion Engineering
Supervisor, EGI Operations
Supervisor, Elec Distribution Ops
Supervisor, Electric Constrctn Engnrng
Supervisor, Electric Distribution
Supervisor, Electric M&C Shift
Supervisor, Engineering Services
Supervisor, Environmental
Supervisor, Facilities
Supervisor, Field Metering
Supervisor, Grid Innovation Engineering
Supervisor, Grid Operations
Supervisor, Land Rights
Supervisor, Land Surveying
Supervisor, Maintenance
Supervisor, Materials
Supervisor, Nuclear Materials
Supervisor, Operations Engineering
Supervisor, Power Quality
Supervisor, Protection Support
Supervisor, Public Safety & Regulatory
Supervisor, Restoration Field Ops
Supervisor, SCADA Operations
Supervisor, Service Planning & Design
Supervisor, Substation Test
Supervisor, System Operations & Control
Supervisor, System Protection Engrng
Supv-Superintendent, Materials
Supv-Superintendent, Nuclear Materials

System Operator

Assistant System Operator
Large Format Oper (1/1/2023 and After)
Lead System Operator
System Operator

Technician

Engineering Tech I
Engineering Technician II
Expert Mapping Technician - Electric
Hiring Hall Engineering Technician I
Hiring Hall Insulation Tester
Lead Mapping Tech-Elec Pass Expert Test
Lead Mapping Technician - Electric
Mapping Technician - Electric
PIO Senior Instrument Technician
Prin Mapping Tech-Elec Pass Expert Test
Principal Mapping Technician - Electric
Senior Engineering Technician
Senior Insulation Tester
Senior Mapping Technician - Electric
Senior Mapping Technician I - Electric
Technologist

Troubleshooter

Transmission Troubleshooter
Transmission Troubleshooter-SF/PN/DA/SJ
Trnsmn UG Troubleshooter-SF/PN/DA/SJ
Troubleshooter
Troubleshooter - SF/PN/DA/SJ
Underground Troubleshooter - SF/PN/DA/SJ

Utility Worker
Hiring Hall Utility Worker - Electric
Hiring Hall Utility Worker- Inexp
Hiring Hall Utility Worker T300 - Exper
Hiring Hall Utility Worker T300 - Inexp
Traveling Utility Worker-Materials
Utility Worker - Elec Mt Dsbn
Utility Worker - Electric Maintenance
Utility Worker - GC
Utility Worker – Tower

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 2

ATTACHMENT B

APPENDIX 2

MWCs IN EACH MWC GROUPING

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 2
ATTACHMENT B
APPENDIX 2
MWCs IN EACH MWC GROUPING

Distribution Projects & Hardening
Capital: 6, 8, 10, 30, 49, 56, 3U
Expense: EW

Distribution Support Services
Capital: 5, 21
Expense: AB, BK, CY, FZ, GE, IG, IS, JV, LJ, OM, OS, WF

Electric Distribution Maintenance
Capital: 7, 2A, 2B, 2C, 2F
Expense: KA, KB, KC

New Business
Capital: 16
Expense: EV

System Inspections & Operations
Capital: 17, 25, 63, 95
Expense: AR, BA, BF, BH, DD, EY, GA, HG, HY, IF, IU

Veg Management
Expense: HN

Transmission & Substation
Capital: 9, 46, 48, 54, 58, 59
Expense: GC, HX

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ELECTRIC DISTRIBUTION RISK MANAGEMENT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
ELECTRIC DISTRIBUTION RISK MANAGEMENT

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ELECTRIC DISTRIBUTION RISK MANAGEMENT

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 3
ELECTRIC DISTRIBUTION RISK MANAGEMENT

A. Introduction and Summary

There are risks inherent in operating an electric system. Pacific Gas and Electric Company (PG&E or the Company) has developed processes and tools to manage these risks. This chapter describes PG&E's Electric Risk Management approach, and how it aligns with PG&E's Enterprise and Operational Risk Management (EORM) framework described in Exhibit (PG&E-2), Chapter 1 on Risk Management. This chapter also identifies and describes each of the Electric Operations risks on PG&E's Corporate Risk Register (CRR) and provides an update to the risk management strategy and risk modeling for the electric risks that were included in PG&E's 2024 Risk Assessment and Mitigation Phase (RAMP) Report.[1]

As described in Chapter 2 on Investment Planning, PG&E makes decisions using a risk-based portfolio approach. That is, a holistic approach is used to evaluate the overall integrity, safety, and reliability to mitigate and control risks across the entire energy delivery system i.e., a family of assets. This Chapter 3 provides additional detail on the risk analysis that informs PG&E's investment plan.

Based on this risk-based portfolio approach, PG&E assesses the portfolio of Electric Distribution Risks to drive investment decisions. The testimony below discusses each Electric Distribution Risk, including changes in risk modelling and responding to SPD feedback. PG&E sees the benefits of its risk mitigations for managing the Wildfire risk. This is based on our use of operational risk mitigations (EPSS and PSPS) as well as the continued investment in near permanent mitigations like System Hardening. With that in mind, PG&E is increasing its focus on mitigating its next highest electric distribution risk, Failure of Distribution Overhead Assets, where the escalation of failures exceed the existing replacement rate.

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1 PG&E's 2024 RAMP Report (May 15, 2024), A.24-05-008.

B. Electric Risk Management Approach

PG&E manages electric risk through a comprehensive approach that includes a structured governance framework, a detailed risk management process, and the use of advanced tools and models. This following section details the various key components.

1. Risk Management Structure and Governance

The Electric Risk Management team sits within the Electric Engineering organization. The Electric Risk Management team is responsible for leading the risk management process and the implementation of the enterprise risk framework, as well as the creation and maintenance of Electric risks on PG&E's Corporate Risk Register. The risk management team supports the Enterprise Business Plan Deployment (BPD) process[2] by providing risk modeling results to enable risk-informed decision-making as part of the work prioritization process. The risk management team also supports the Risk Owners. Risk Owners provide a single point of accountability for fully understanding and managing the health and risk of the assets within an asset family.

There is also an additional department dedicated to Wildfire Risk established in March 2021. The Wildfire Risk Management organization operates under the leadership of a Senior Director focusing on preparation and implementation of programs for preventing, mitigating, and controlling the threat of catastrophic Electric system incidents during the wildfire season. This organization oversees Ignitions Investigations, Strategy and Engagement, Program Management and Execution, and Risk Management and Analytics.

PG&E has multiple layers of governance committees, both within Electric and at the enterprise level. The following is a list and description of the governance risk committees where Electric representatives actively participate to drive decisions, transfer knowledge, and create community and regulatory governance:

- **Safety, Nuclear, and Operations (SNO) Oversight Committee** – The SNO committee has oversight review of enterprise-level risk

[2] Exhibit (PG&E-2), Ch. 2.

management activities. The status of Wildfire risk and various Electric risks are regularly communicated to this committee.

- **Electric Risk and Compliance Committee (RCC)** – This committee is chaired by the SVP of Electric Engineering, Planning and Strategy and includes all Electric VPs and compliance senior directors. The RCC meets monthly to provide oversight for Electric Transmission and Distribution risks and compliance performance, raise and resolve issues, and share best practices.
- **Wildfire Risk Governance Steering Committee (WRGSC)** – This committee makes decisions specifically focused on the Wildfire risk, given that it is the top risk for the company. The WRGSC is chaired by the Chief Risk Officer and includes the SVP of Wildfire and Emergency Operations, Sr Director of Data, Analytics, and Insights, SVP of Electric Engineering, SVP of Electric Operations, SVP of Local Customer Engagement, VP of Enterprise Financial Risk Management, and VP of Vegetation Management as voting members. The meetings occur more frequently than monthly to provide oversight for Wildfire risk management activities that seek to prevent catastrophic wildfires, mitigate wildfire risk, and reduce customer impacts.
- **Risk Management Community** – This community of employees engage Functional Area (FA) Risk Managers and Investment Planning (IP) Managers with Enterprise Risk management and Modeling Teams in supporting PG&E's risk management goals as determined by the Enterprise Risk Committee and FA Risk and Compliance Committees; align on cross-functional processes and tools related to improving risk-based, data-driven decision making.

2. Risk Management Process and Tools

The four major steps in the risk management process has not significantly changed since the last 2023 GRC filing[3] or from the 2024 RAMP Report, however, there have been some significant changes in the tools used. Electric Operations uses the Cost-Benefit Approach and Cost

[3] A.21-06-021, 2023 General Rate Case Application of Pacific Gas and Electric Company (June 30, 2021).

Benefit Ratios (CBR) to evaluate risk and associated mitigation and control programs. Electric Operations policy and process is consistent with the EORM FA risk management policy and process as described in Exhibit (PG&E-2), Chapter 1, Section C.3. The Wildfire Risk modeling is another major tool update, transitioning from WDRM V3 to V4 since the 2024 RAMP Report and moving from 25 tranches (5 CoRE by 5 LoRE quintiles) to 42 tranches (decile) since TY 2023 GRC.

Below are the four major steps in the risk management process with a brief description:

- **Step 1: Risk Identification** – Electric Operations employs a horizon scanning process to identify new and emerging risks. Horizon scanning is an analysis of trends and key risk indicator (KRI) metrics, issues identified through Corrective Action Plan (CAP) submissions, engineering studies and cause analysis, surveys, and feedback from regulators. For instance, the model for assessing the risk of a Failure of Electric Distribution Substation Assets considered only historical outages, failing to account for the value of redundancy and potential risks associated with operating in an abnormal operating configuration. The horizon scanning process revealed heightened concerns regarding consecutive multiple asset failures, which pose a significant vulnerability to the electric system. Upon identifying this gap, the model was refined to incorporate the redundancy component, thereby providing a better representation of the existing risk.
- **Step 2: Risk Evaluation and Quantification** – The evaluation and quantification of our risk bowties and benefits of our control and mitigation programs are heavily driven by regulatory requirements from the California Public Utilities Commission and the Risk-Based Decision-Making Framework (RDF): R.20-07-013. The goal of the RDF is to increase the transparency and accountability of prioritization and mitigating safety risks. The presentation of risk scores are in dollars allowing for direct comparisons across risks. Procedures are followed to create, augment, or refresh bowties in addition to evaluating the effectiveness of control and mitigation programs to maintain or reduce risk on our system.

- **Step 3: Risk Response** –The Risk Owner is responsible for developing a risk reduction strategy that achieves risk reduction targets. The strategies inform the risk control and mitigations. Analysis of these controls and mitigations in addition to costs, allows for the calculation of CBRs. Program CBRs are one input that informs funding decisions.
- **Step 4: Risk Monitoring and Reporting** – Key Risk Indicators (KRI) are undergoing ongoing enhancements. The objective of a KRI is to provide an indication of the risk trend that provides advance warning of any changes in risk requiring management review and action to prevent risk events from materializing.

Table 3-1 identifies the Electric Operations risks on PG&E's Corporate Risk Register (CRR) in order of highest to lowest 2027 test year baseline risk scores. Electric transmission risks are shown in the Table for completeness but are not included in the 2027 GRC. Risks that were presented in PG&E's 2024 RAMP Report are listed, along with relevant chapter references. For information on how PG&E selected risks for inclusion in its 2024 RAMP Report, see PG&E's RAMP Report, Exhibit (PG&E-2), Chapter 4. In PG&E's 2023 GRC Application, Emergency Preparedness and Response was included in the Electric exhibit and is now located in Exhibit (PG&E-7), Chapter 9.

TABLE 3-1
ELECTRIC OPERATIONS RISKS

Line No.	Risk Name and Description	RISK ID	2024 RAMP Report Chapter
1	**Wildfire with PSPS and EPSS** The baseline wildfire risk is defined as a wildfire originating from PG&E assets or activities that may endanger the public, private property, sensitive lands, or environment. The Wildfire risk with Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS) accounts for the benefits and consequences of operational mitigations when PSPS and EPSS are implemented.	WLDFR, WPSPS, WEPSS	Exhibit (PG&E-4), Ch. 1
2	**Failure of Electric Distribution Overhead Assets** The failure of distribution overhead assets or remote operation functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.	DOVHD	Exhibit (PG&E-4), Ch. 4
3	**Electric Transmission System Wide Blackout** A system-wide disturbance leading to a cascading event that causes a blackout of PG&E's electrical system, with the inability to restore the grid in a timely fashion.	BLKOT	Exhibit (PG&E-4), Ch. 2
4	**Failure of Electric Distribution Underground Assets** The failure of distribution underground assets or remote operation functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy. Underground assets include radial and network primary distribution.	DUNGD	Exhibit (PG&E-4), Ch. 5
5	**Failure of Electric Transmission Overhead Assets** Failure of transmission overhead assets or remote operation functionality that may result in public or employee safety issues, property damage, environmental damage, disruption of major generation sources and inability to deliver energy.	TOVHD	Non-RAMP Risk
6	**Failure of Electric Distribution Substation Assets** The failure of distribution substation assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, disruption of major generation sources, or inability to deliver energy.	DSBSN	Non-RAMP Risk

TABLE 3-1
ELECTRIC OPERATIONS RISKS
(CONTINUED)

Line No.	Risk Name and Description	RISK ID	2024 RAMP Report Chapter
7	**Failure of Electric Transmission Substation Assets** Failure of transmission substation assets or remote operation functionality that may result in public or employee safety issues, property damage, environmental damage, disruption of major generation sources or inability to deliver energy.	TSBSN	Non-RAMP Risk
8	**Failure of Electric Transmission Underground Assets** Failure of transmission underground assets or remote operation functionality that may result in public or employee safety issues, property damage, environmental damage, reduced operational redundancy in critical urban centers, or large-scale prolonged outages.	TUNGD	Non-RAMP Risk
9	**Public Contact with Intact Energized Electrical Equipment** Public Contact with Intact Energized Electrical Equipment is the risk of a reportable serious injury or fatality to a third-party contractor or member of the public from an interaction with PG&E electric assets that did not originate from asset failure.	PCEEE	Exhibit (PG&E-4), Ch. 3

The Electric Risk Management Team employs a variety of tools and models to evaluate risk and make data-driven risk-informed decisions. To evaluate the benefits of our risk controls and mitigation programs, PG&E employs its enterprise Cost-Benefit Approach (CBA) risk models to inform the investment planning process. To evaluate prioritization of work within a workplan, PG&E leverages our more granular planning models including the Wildfire Distribution Risk Model (WDRM). Table 3-2 describes the key Electric Risk Management models and how they are used.

TABLE 3-2
ELECTRIC RISK MANAGEMENT MODELS

Line No.	Model Name	Abbreviation	Description
1	Enterprise Cost-Benefit Approach Risk Model	2024 RAMP/2027 GRC Enterprise Risk Model	• Model used in PG&E's 2024 RAMP and 2027 GRC • Aligned to the S-MAP requirements • Assess enterprise risks using a common framework • Used to develop risk scores, safety scores, bowtie, and CBR values
2	Wildfire Distribution Risk Model	WDRM v4	• Planning model • Calculates wildfire risk probabilities of ignition and consequence scores for the entire overhead distribution system at the circuit segment level • Informs the development of mitigation programs; helps prioritize highest wildfire risk miles on PG&E's entire distribution system • Outputs inform PG&E's System Hardening and Vegetation Management work planning and scheduling
3	Wildfire Consequence Model	WFC v4	• Estimates the expected outcome of a wildfire initiated by an ignition from an electric asset • Supports the WDRM mission to quantify and categorize wildfire risk from overhead assets • Consists of simulating a combination of three events: spread of fire, suppression, and egress
4	Public Safety Consequence Model	PSC v3	• Evaluates the direct impact to the public's safety by calculating a "safety consequence score" on any asset across the system territory • Enables prioritization of asset inspections and asset replacements
5	PSPS Consequence Model	N/A	• Model to assess PSPS customer impacts at the circuit segment and service point level

C. Risk Assessment and Mitigation Phase (RAMP) Risk Updates

PG&E's 2024 RAMP Report included four electric distribution-related risks: Wildfire, Public Contact with Intact Energized Electrical Equipment, Failure of Electric Distribution Overhead Assets, Failure of Electric Distribution Underground Assets. In the sections that follow, PG&E describes these RAMP

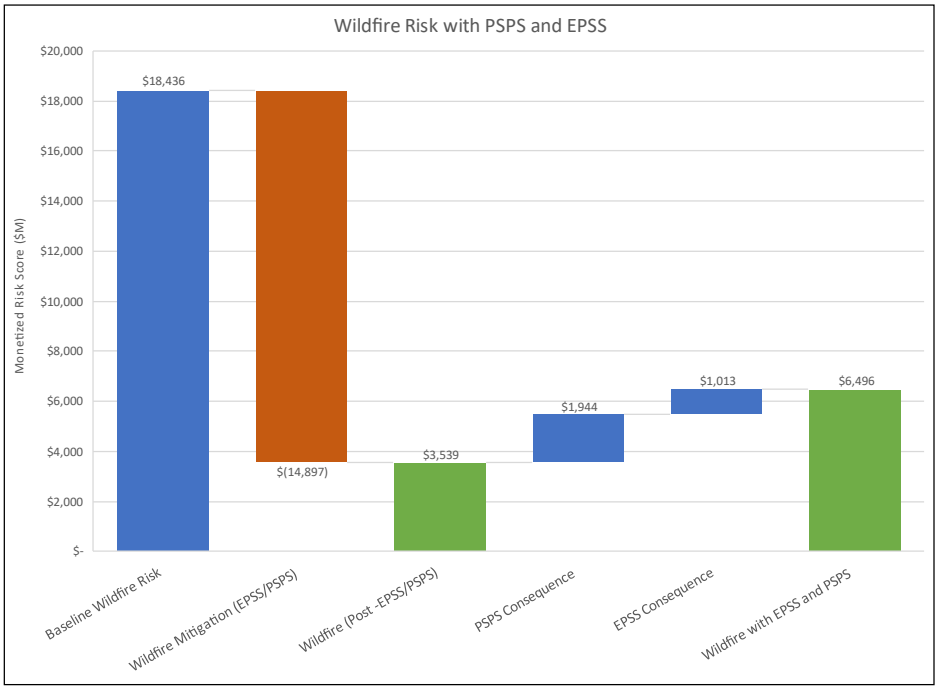
risks along with any changes to the risk models, controls, mitigations, and CBRs since PG&E filed the 2024 RAMP Report.

1. Wildfire With PSPS and EPSS

a. Risk Overview

The baseline wildfire risk is defined as a wildfire originating from PG&E assets or activities that may endanger the public, private property, sensitive lands, or environment. The Wildfire risk with Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS) accounts for the benefits and consequences of operational mitigations when PSPS and EPSS are implemented. Figure 3-1 presents PG&E's Wildfire Risk, the benefits of deploying PSPS and EPSS in reducing our overall Wildfire Risk, the reliability consequences from deploying PSPS and EPSS mitigations, and the net impact to Wildfire Risk on our system, considering deployment and its consequences.

FIGURE 3-1
2027 TY BASELINE - WILDFIRE WITH PSPS AND EPSS WATERFALL



- **Baseline Wildfire Risk**: Considers baseline risk without utilization of PSPS and EPSS operational mitigations. This is the Wildfire Risk

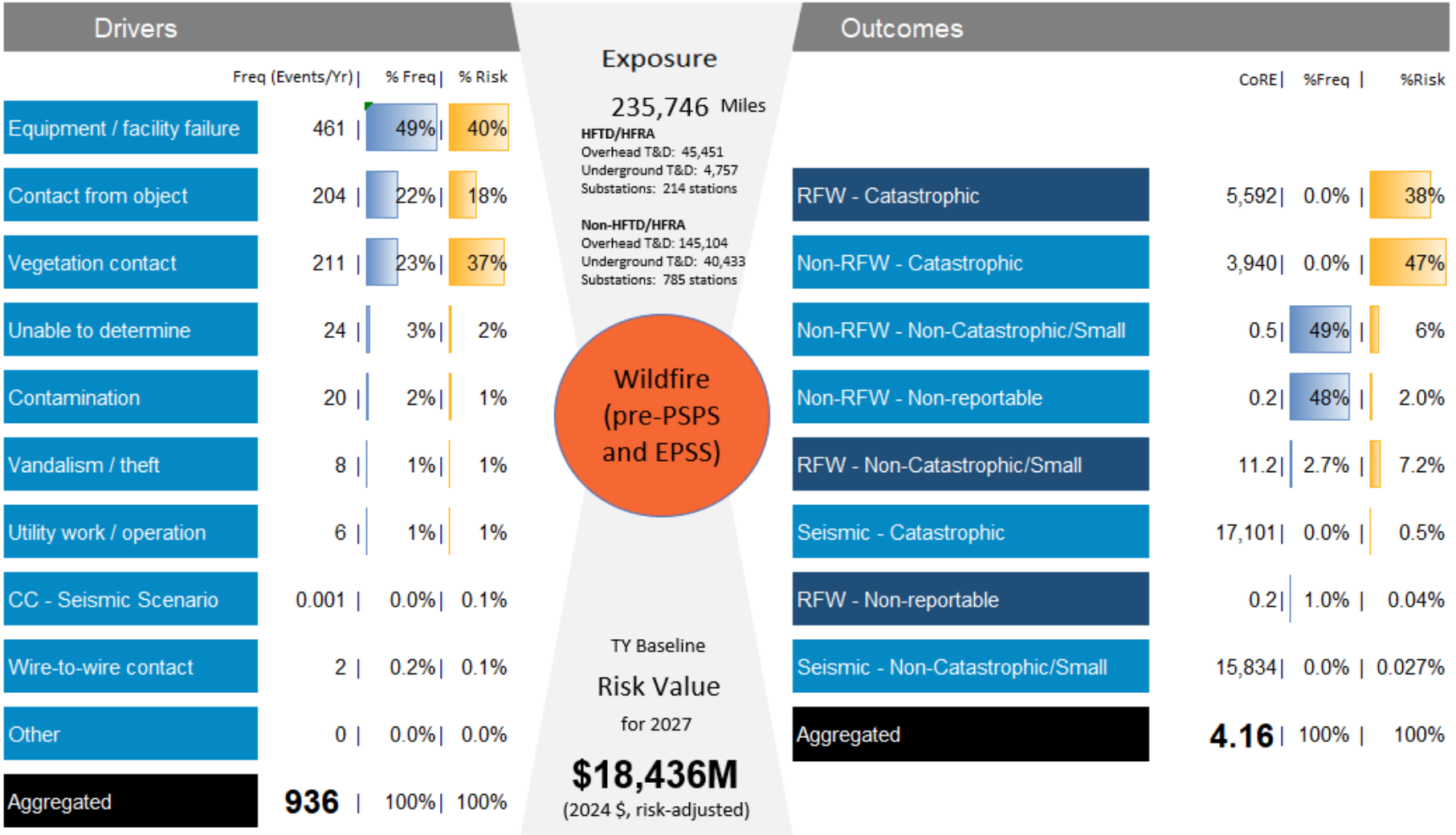
that PG&E faces, based on its service territory and current assets. As additional system resilience mitigations are deployed, this baseline risk will decrease, as the expected frequency or consequence of wildfires will be reduced.

- **Wildfire Mitigation (EPSS/PSPS):** Risk reduction due to EPSS and PSPS
- **Wildfire (Post-EPSS/PSPS) Risk**: Considers the net resulting baseline risk while utilizing PSPS and EPSS as wildfire mitigations. For reference, this is what PG&E customers experience "day to day" as it relates to Wildfire Risk but is not a true reflection of the Wildfire Risk, given human operational mitigations involved. This also does not include the reliability consequences associated with the operational mitigations deployed.
- **PSPS Consequence**: Considers the negative impact of PSPS to customers. This is the risk that PG&E customers experience related to a "PSPS event," where as a last resort lines are de-energized pre-emptively to an incoming weather event and conditions that can lead to a catastrophic fire.
- **EPSS Consequence**: Considers the negative impact of EPSS to customers. This is the risk that PG&E customers experience related to additional outages from the EPSS settings being enabled. These settings disable automatic reclosing operations and make protection devices more sensitive to fault currents.
- **Wildfire with EPSS and PSPS**: Considers the net resulting risk of the wildfire plus the negative impacts of PSPS and EPSS. This is the risk PG&E customers experience collectively in the reduced Wildfire Risk but worsened reliability performance. The operation and impact of PSPS and EPSS is driven by the need to continually manage the significant safety risk that is posed by catastrophic wildfires.

PG&E created several bowties and risk scenarios to demonstrate its wildfire risk with consideration of the benefits of PSPS/EPSS and its negative reliability impacts. These models include: (1) Baseline Wildfire Risk (Figure 3-2), (2) Post PSPS/EPSS Wildfire Risk (Figure 3-3), (3)

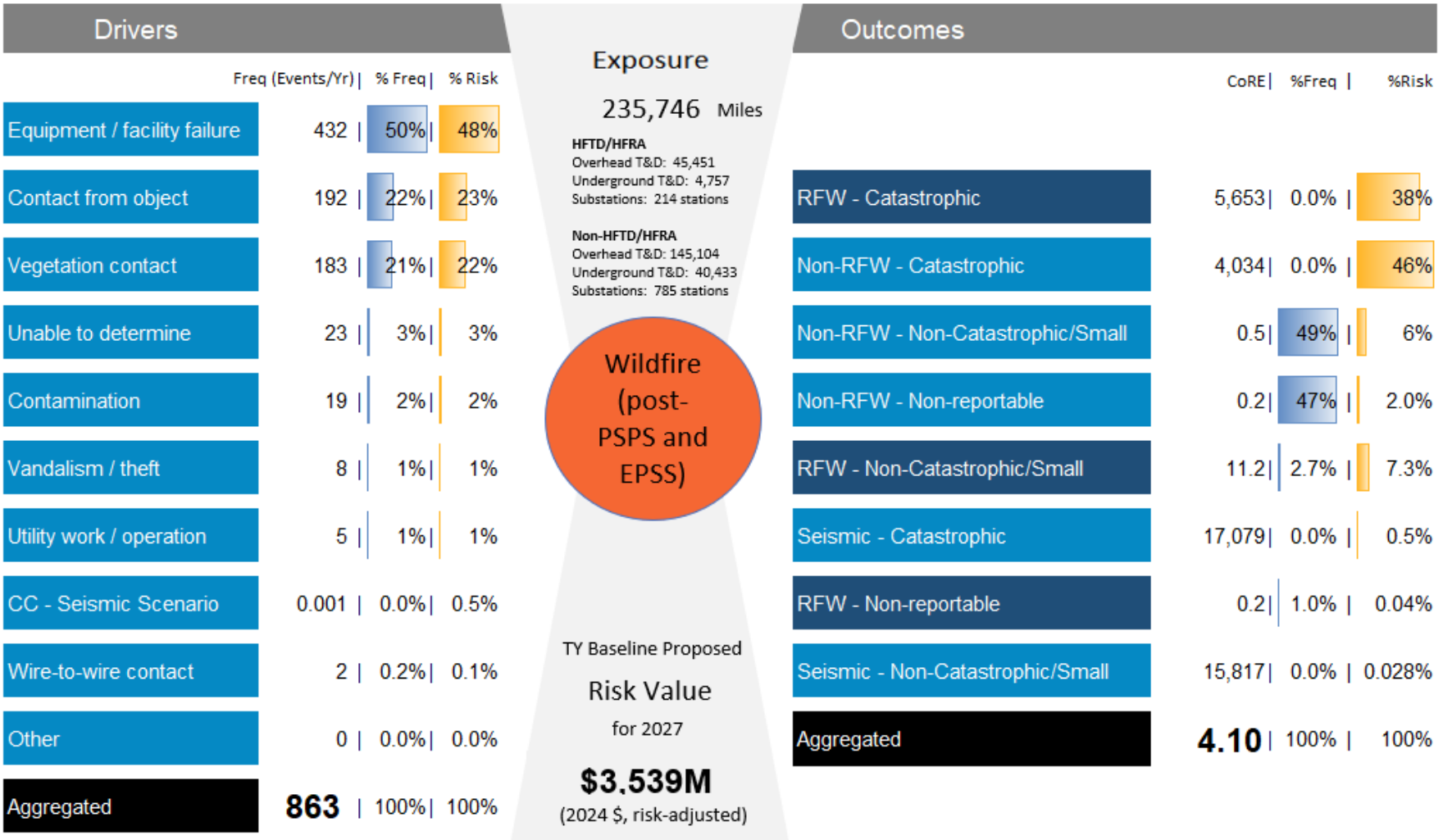
PSPS Consequence (Figure 3-4), (4) EPSS Consequence (Figure 3-5), and (5) the full Wildfire with PSPS and EPSS Risk.

FIGURE 3-2
WILDFIRE RISK BOWTIE – SYSTEMWIDE WILDFIRE RISK



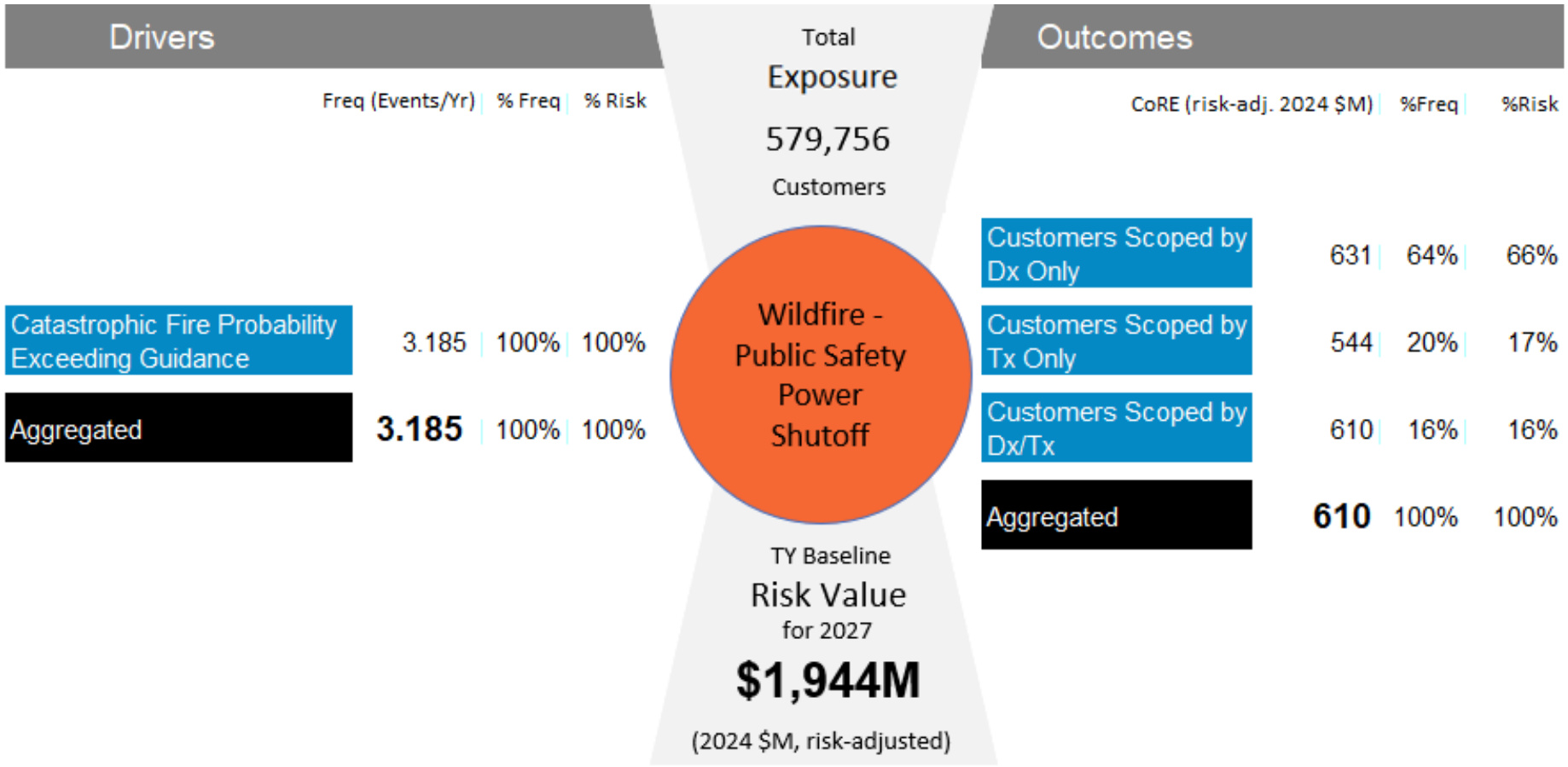
(PG&E-4)

FIGURE 3-3
WILDFIRE RISK POST PSPS/EPSS BOWTIE, PG&E SYSTEMWIDE



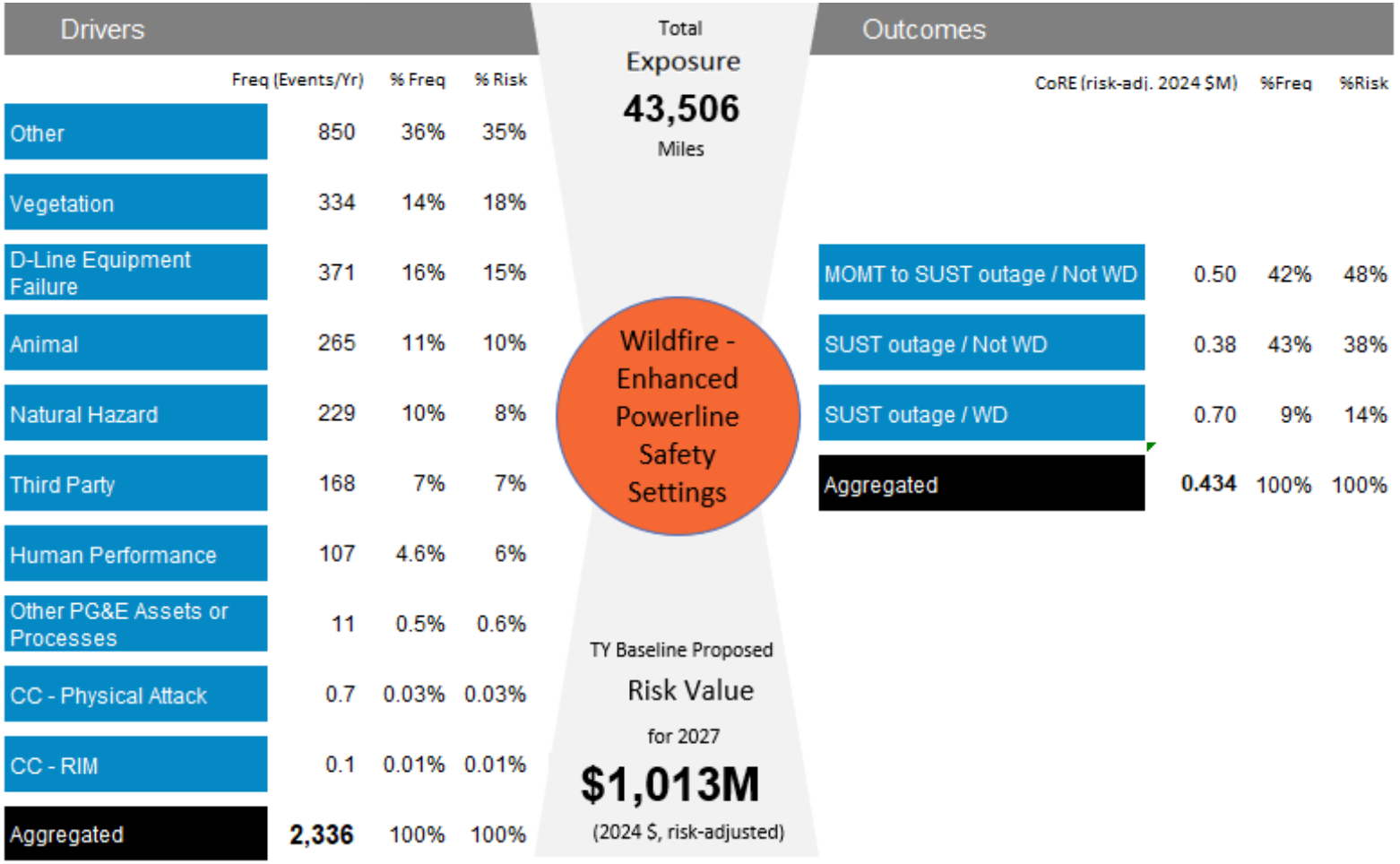
(PG&E-4)

FIGURE 3-4
PSPS CONSEQUENCE BOWTIE



(PG&E-4)

FIGURE 3-5
EPSS CONSEQUENCE BOWTIE



(PG&E-4)

In Figure 3-2 and Figure 3-3, the 10 drivers of Wildfire Risk originating from PG&E assets or activities are Equipment Failure, Vegetation Contact, Contact from Object, Unable to Determine, Contamination, Other, Wire-to-Wire Contact, Seismic Scenario, Utility Work/Operation, and Vandalism/Theft. In the Baseline Wildfire Risk, the top three drivers, Equipment Failure, Vegetation Contact, and Contact from Object, account for 94 percent of the events and 95 percent of the risk. In the Wildfire (Post-EPSS/PSPS) Risk, the top three drivers remain the same and account for 93 percent of the events and risk. The cross-cutting factors[4] which impact the risk are climate change, cyber attack, Emergency Preparedness and Response (EP&R), Information Technology (IT) asset failure, physical attack, Records Information Management (RIM), and seismic.[5] Only climate change, physical attack, RIM, and seismic cross-cutting factors are quantified in the model.

Exposure for the Wildfire Risk is measured in circuit miles and totals to approximately 236,000[6] circuit miles in PG&E's electric distribution and transmission systems. Wildfire Risk is separated by location and facility type, with further granularity established for the distribution risk based on WDRM. Altogether, this framing results in 50 tranches:[7] location (HFRA/HFTD vs non-HFRA/HFTD), facility types (Distribution Overhead, Transmission Overhead, Substation, and Transmission and Distribution Underground), and distribution (primary, secondary, services, and underground) or transmission (60/70kV, 115 kV, 230/500 kV, and substation). The red flag warning catastrophic

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4 A cross-cutting factor is an item that is not a risk event itself, but rather impacts either the likelihood or consequence of other risks on the CRR.

5 Exhibit (PG&E-2), Ch. 1, Attachment B lists each of the RAMP risks and RAMP cross-cutting factors.

6 Approximately 16,000 miles are secondary miles. Approximately 76,000 miles are service miles estimated using 150 feet per customer connected to overhead lines. Refer to Exhibit (PG&E-4), WP EO-WLDFR-10_Tranche Exposure.xlsx for wildfire exposure breakdown.

7 A tranche represents a group of assets that are determined to have a similar risk profile associated with Likelihood of Failure (LOF) and Consequence of Failure (COF) risk events.

outcome accounts for 82 percent of the risk but occurs 0.2 percent of the time.

The PSPS bowtie (Figure 3-4) has a single driver, Catastrophic Fire Probability Exceeding Guidance. This driver represents environmental and meteorological conditions exceeding the established PSPS guidance. The guidance has been set to capture the conditions where the largest historical fires occurred, to avoid future ignitions under similar conditions. This driver assumes that when the PSPS guidance thresholds are met that the decision will be made to initiate a PSPS event and de-energize the affected circuit segments. PSPS exposure is measured as customers exposed to PSPS risk. The PSPS model is a lookback, which means it utilizes historical information with the current de-energization guidance at a circuit segment to identify the aggregate consequence of events and their frequency. The exposure used in the model is approximately 580,000 customers, based on the customers that are potentially impacted by this lookback. PSPS risk is tranched by customer classification which is described below:

- **Extreme**: Public Safety Partners;
- **Significant**: Life Support customers or Medical Baseline customers who are low income;
- **Elevated**: Access and functional needs customers (exclusive of Life Support or Medical Baseline customers who are low income), all other critical customer designations; and
- **Regular**: Regular customer.

These classifications combine several customer factors to identify the significance of the impact an outage would have. These classifications help to allocate the risk of a PSPS event but are not used to change the overall expected consequence of a PSPS event. Approximately for 85 percent of the time customers are scoped by distribution or by transmission and account for about 85 percent of the risk.

EPSS bowtie (Figure 3-5) drivers are defined the same as the Failure of Electric Distribution Overhead Assets risk (DOVHD) drivers

described in Section C.2. The EPSS risk has been quantified as the difference between the DOVHD risk with and without EPSS.

The distribution of drivers is different from the DOVHD risk, as the frequency of drivers that occur during EPSS activation is different than what occurs when EPSS is not activated. The top four drivers (Other, Vegetation, D-Line Equipment Failure, and Animal) account for about 80 percent of the risk events and comprise of 80 percent of the risk. The Other driver consists of outages where a cause cannot be identified, which increases under EPSS conditions as momentary outages are converted into sustained outages due to the increased sensitivity of the protection settings.

EPSS exposure is the mileage of overhead primary circuits that are EPSS capable. EPSS capable means the circuits could have EPSS enabled when the enablement criteria are met. The EPSS exposure used in the model is approximately 43,000 miles, estimated based on the number of miles that are EPSS capable.

EPSS tranches are defined the same as the Failure of Electric Distribution Overhead Assets risk (DOVHD) tranches described below. The EPSS risk utilizes the same drivers as the DOVHD risk, and the risk deciles that create the DOVHD tranches are also representative of EPSS risk. Moving from a momentary to a sustained outage that is not a wire down, and sustained outages that are not a wire down are approximately 85 percent the outcome and risk.

b. Responding to Safety Policy Division (SPD) and Parties' Feedback on PG&E's 2024 RAMP Report

In October 2024, Cal Advocates, The Utility Reform Network (TURN), Energy Producers & Users Coalition and the Indicated Shippers (EPUC/IS), Mussey Grade Road Alliance (MGRA), and Small Business Utility Advocates (SBUA) provided informal comments on PG&E’s 2024 RAMP Application (A.) 24-05-008. On November 8, 2024, the SPD issued its Staff Evaluation Report. PG&E appreciates SPD and parties’ feedback and as shown agrees with many of the comments and recommendations received. A list of the feedback and PG&E’s

response to each item is provided in Exhibit (PG&E-2), Chapter 1, WP 1-01_RAMP to GRC Feedback.

There are several SPD comments regarding the overall wildfire mitigation strategy, prioritization, and providing justification, which will be addressed in the following paragraphs. SPD recommended PG&E to clarify whether and how it uses CBR values to select the most efficient risk mitigation measures at both the circuit segment and tranche. SPD also recommends that PG&E research the nature of risk drivers that lead to catastrophic outcomes, and then develop a mitigation workplan that focuses on mitigating those drivers where possible.

The same drivers that lead to a catastrophic wildfire are the same as large and small wildfires. Wildfires follow a predictable progression as pictured in Figure 3-6. The complete portfolio of wildfire mitigations is designed to disrupt the wildfire sequence at various critical stages, breaking the chain reaction that can lead to catastrophic fires. In the selection of mitigation programs, the portfolio of mitigation programs target both the highest drivers, as well as steps to interrupt the wildfire sequence, based on overall risk and cost benefit. Various mitigation programs are used at the different steps in the sequence to halt fire development before it reaches an uncontrollable stage.

FIGURE 3-6
WILDFIRE SEQUENCE



PG&E continues to build on the existing layers of protection rooted in a solid foundation of mitigations since 2019. These layers of protection include: (1) permanent risk reduction through System Hardening activities, (2) programs targeting highest ignition drivers, and (3) operational controls such as EPSS and PSPS to mitigate ignition risk during higher probability ignition days. Our wildfire mitigation strategy includes first preventing wildfire ignitions, then, where ignitions do occur,

ensuring swift response to limit the scale of any incidents, and finally supporting efforts to improve forest fire resilience to reduce wildfire consequence. By combining advanced technologies, system upgrades, and collaborative efforts with communities and agencies, PG&E aims to build resilient infrastructure and a safer environment.

The first layer of protection aims to prevent ignitions and reduce wildfire risk through system hardening and undergrounding activities, which are permanent investments with long-term benefits. In the Electric Undergrounding Plan (EUP), PG&E will provide detailed quantitative data on EUP-eligible circuit segments that will show Energy Safety, other regulators, and stakeholders how it compares mitigation strategies.

In the second layer of protection, concurrently with the first layer since the implementation cannot be immediate, are programs addressing the highest frequency drivers: vegetation contact, equipment failure, and contact with objects. Vegetation inspections, pole clearing, utility defensible space, and the wildfire resiliency fuels treatment program are a few examples reducing the frequency of vegetation contact or consequence of wildfire. Asset maintenance or replacement programs, in particular, overhead electric notifications and pole replacements are a few of the highest funded programs to address equipment failure. For contact with objects, the animal abatement programs address the frequency of the animal driver.

In the third and last layer of protection is our operational mitigations, EPSS and PSPS. Operational mitigations can come with significant customer impacts. On addressing SPD’s request to provide information on what steps PG&E is taking to reduce PSPS and EPSS impacts, there are processes and programs that alleviate customer impact where feasible. These programs include the installation and use of sectionalizer devices that help limited downstream customers from EPSS or PSPS; using helicopters and drones to aid visual inspection when not possible by ground patrol to decrease outage duration for EPSS; vegetation management to complete work (prune or remove trees) on any other similarly situated vegetation that caused an EPSS

outage; clearing of incremental electrical or vegetation tags before a PSPS event; and animal abatement targeted on EPSS lines. Both temporary generation and customer battery programs aim to reduce customer impact from outages. Additionally, the permanent investment in undergrounding also reduces the PSPS and EPSS impacts.

Given the various layers of protections, PG&E uses a risk-informed decision-making process relying on inputs from key Wildfire Risk models that are continuously improved and expanded. PG&E uses two types of models to address the dynamic wildfire risk across our service territory: operational models for operational mitigations such as PSPS and EPSS that show where fire risk is elevated in the short-term, and long-term planning models for resiliency programs that permanently reduce risk by hardening the grid. The WDRM v4 model is a significant evolution in the approach to quantifying the wildfire risk from overhead distribution assets. Utilizing machine learning, the model combines enhanced event probability assessments and new models for several equipment classes with an upgraded wildfire consequence model. From the WDRM model, circuit segments can be risk ranked and leveraged as an input on the location and type of mitigation that should occur. There are other considerations and factors when determining workplans and prioritization, such as bundling of work. This is evident in vegetation, where vegetation management utilizes the WDRM to prioritize wildfire risk mitigation work while also aiming to reduce repeat visits. Consequently, even within a program, circuit segments can be prioritized through a risk ranking based on the driver. The enterprise risk model aggregates these WDRM circuit segments into 42 tranches (10 HFRA Primary, 10 non-HFRA Primary, 10 HFRA Secondary, 10 HFRA Services, 1 non-HFRA Secondary, 1 non-HFRA Services) for summarizing and presenting the risk and risk reduction at a digestible granularity. Most of the program workplans are developed at the circuit segment or circuit level and then mapped to the tranche level. It also informs users at a high level of possible mitigations that can be developed to mitigate drivers or consequence.

In some cases, it may not be feasible to implement high CBR value programs everywhere. CBR values are an input in the risk reduction strategy decision. The Risk-Based Portfolio Prioritization Framework (RBPPF) establishes a framework for evaluating the selection of investments across multiple organizations within PG&E. Funding tiers are assigned to value various categories to recognize high impact urgent work. Program CBR values is one input that helps inform funding decision. For more information, refer to Exhibit (PG&E-4), Chapter 2, which discusses RBPPF.

c. Risk Modeling Updates

Since RAMP, the historical source data used to predict the frequency and consequence of ignitions have been updated to include incidents from 2023 and 2024 whenever applicable. The WDRM used for distribution tranches has updated from version 3 to version 4. Additionally, the safety monetized value has changed from $15.23 million to $16.2 million. This is the value of a statistical life from the Bureau of Labor Statistics, which has then been adjusted to California dollars. The value of service is calculated using the original Interruption Cost Estimate (ICE) calculator and has slightly increased from $3.17 to $3.33 based on PG&E 2024 recorded customer counts and consumption values. For further discussion on the ICE calculator update, reference Exhibit (PG&E-2), Chapter 1, Section C.

The effectiveness values for EPSS and PSPS have been updated. For EPSS effectiveness, PG&E has shifted to a Fire Potential Index (FPI) – stratified methodology to align with the WMP. The EPSS effectiveness is now the ignition frequency weighted average of the effectiveness per FPI.[8]

For PSPS, the historical lookback analysis has been updated to the latest PSPS guidance, referred to as PSPS 5.0 Guidance, for years 2018 through 2022. The lookback dataset excludes events from 2023 and 2024 due to incomplete meteorological data at the time of analysis.

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8 For more detailed information on EPSS and PSPS effectiveness values, refer to Exhibit (PG&E-4), Chapter 3, WP EO-WLDFR-M001_PSPS_M020_EPSS_M021_EPSS and PSPS.

However, since PG&E anticipates utilizing SCADA exclusively for 2025 onwards, for years 2023 and 2024, actual events were used and modified to model the next upstream SCADA device. Additionally, there is a slight adjustment in the categorization of Elevated, which now captures all access and functional needs customers who are not already captured in the Significant category.

d. Changes in Risk Controls and Mitigations

Overall changes in risk controls and mitigations include revised effectiveness values and workplans due to better available data. Attachment A "Foundational Activities, Controls and Mitigations for RAMP and Non-RAMP Risks" provided at the end of this chapter presents a comprehensive list of the foundational activities, controls and mitigations for Electric Distribution RAMP and non-RAMP Risks included in the 2027 GRC. The Commission defines foundational programs and/or activities as initiatives that support or enable two or more mitigation programs or two or more risks but do not directly reduce the consequences or the likelihood of risk events. The table identifies MAT codes applicable to each risk program and includes relevant forecast chapter references as well as a comparison of CBRs between the 2027 GRC and 2024 RAMP for programs that were also presented in the 2024 RAMP. Some Controls and Mitigations reduce risk for multiple risks as shown in the Risk Program ID column. For reference, see Table 3-1 for a mapping of Risk ID to the Enterprise Risk Name and, where applicable, the risk chapter from PG&E's 2024 RAMP.

Failure rates have also been adjusted to consider specific asset conditions. For a complete history of foundational activities, controls, and mitigations for WLDFR with PSPS and EPSS since the 2024 RAMP Report, refer to Attachment B, "2024 RAMP to 2027 GRC Risk Program Index" Table 3-4 through Table 3-6 provided at the end of this chapter.

There are a few naming changes in the vegetation management mitigations. Focused Tree Inspection (WLDFR-M028, DOVHD-M028, WEPSS-M008) is now called Targeted Inspection, and Pole Clearing – Routine (WLDFR-M027, DOVHD-M027, WEPSS-M007) is renamed to

Vegetation Control/Right of Way Clearing. Details about these mitigations are in Exhibit (PG&E-4), Chapter 8, Section B.3.

One significant change in the vegetation controls and mitigations is the consolidation, or bundling, of work. The Routine Patrol WLDFR-C001 has been redefined to include the scope and effectiveness values of Routine Patrols, Targeted Inspection, and Tree Removal Inventory (TRI). Second Patrols WLDFR-C002 has been redefined to be called Hazard Patrol and includes the scope of Second Patrols and Vegetation Management for Operational Mitigations (VMOM). CBR calculations have been calculated separately and aggregated into one overall CBR.[9]

PG&E is proposing new wildfire mitigations and controls, see Attachment B, Table 3-6 through Table 3-8 at the end of this chapter. New risk programs include Wildfire Resiliency Fuels Treatment; Breakaway Connectors; Utility Defensible Space; Generator and Battery Rebate Program; BTM Capital Battery Program; PSPS Granular Sectionalizing; and Wildfire Helicopter Assistance.

2. Failure of Electric Distribution Overhead Assets

a. Risk Overview

The failure of distribution overhead assets or remote operation functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy. Failure of assets associated with PG&E's overhead (OH) electrical distribution system include poles and support structures; primary and secondary conductor; voltage regulating equipment; protection equipment; switching equipment; transformers; and PG&E owned streetlights.

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9 Refer to Exhibit (PG&E-4), WP EO-WLDFR-19_Hazard_Patrol_CBR.xlsx and EO-WLDFR-19_Routine_Patrol_CBR.xslx for the consolidated CBR calculations.

FIGURE 3-7
FAILURE OF ELECTRIC DISTRIBUTION OVERHEAD ASSETS BOWTIE



Figure 3-7 illustrates the Failure of Electric Distribution Overhead Assets bowtie. The 11 drivers are vegetation; distribution line equipment failure; other; third-party; animal; natural hazard; other PG&E assets or processes; human performance; physical attack (cross-cutting); and records and information management (cross-cutting). The top three drivers, vegetation, distribution line equipment failure, and other account for about 80 percent of the frequency and risk.

The cross-cutting factors are climate change, physical attack, records, and information management, and seismic. Exposure to this risk is based on approximately 80,000 circuit miles of primary conductor and associated assets including secondary and services. PG&E utilizes 20 tranches, which reflects the population of primary conductor miles divided into 10 deciles of risk and then separated by High Fire Threat Districts (HFTD)/High Fire Risk Areas (HFRA) (32 percent of the risk) or non HFTD/HFRA (68 percent of the risk).

b. Responding to Safety Policy Division (SPD) and Parties' Feedback on PG&E's 2024 RAMP Report

In October 2024, Cal Advocates, The Utility Reform Network (TURN), Energy Producers & Users Coalition and the Indicated Shippers (EPUC/IS), Mussey Grade Road Alliance (MGRA), and Small Business Utility Advocates (SBUA) provided informal comments on PG&E's 2024 RAMP Application (A.) 24-05-008. On November 8, 2024, the SPD issued its Staff Evaluation Report. PG&E appreciates SPD and parties' feedback and as shown agrees with many of the comments and recommendations received. A list of the feedback and PG&E's response to each item is provided in Exhibit (PG&E-2), WP 1-01_RAMP to GRC Feedback.

SPD expressed concerns about the risk assessment for DOVHD, particularly the "Other" category, which accounts for a significant portion of annual risk events, recommending more granular details on this category in future filings. The "Other" category involves failures without known causes. PG&E considers the balance and trade-offs on the need to further investigate with limited resources, hence, the "Other" category was created. PG&E will continue efforts to identify causes within reasonable limits.

SPD also noted changes in outcome categories between the 2020 and 2024 RAMP filings, specifically the removal of IT asset failure coincidence and the introduction of wire-down and EPSS components. They recommended that PG&E explain these changes in the 2027 GRC filing. The IT asset failure outcome category has been removed from the DOVHD risk model due to low quality of modelling around coincident event, and it has a very low risk contribution.

Finally, SPD recommended providing detailed narrative justifications for controls and mitigations with CBRs less than 1.0 as well as presenting the individual risk benefit contribution for programs that produce benefits for multiple risks. Justifications are elaborated in the corresponding forecast chapters, Chapter 4 through Chapter 23. Programs that benefit multiple risks, the individual risk benefit contribution to the total risk reduction and the individual risk contribution

to the program CBR is included in Exhibit (PG&E-2), WP 1-14_GRC Mitigations and Controls and their CBRs.

c. Risk Modeling Updates

Since RAMP, PG&E updated the historical frequency source data for serious injury and fatality and the outage data to include incidents and outages from 2023 and 2024. Additionally, the safety monetized value has changed from $15.23 million to $16.2 million. This is the value of a statistical life from the Bureau of Labor Statistics, which has then been adjusted to California dollars. The value of service is calculated using the original Interruption Cost Estimate (ICE) calculator and has slightly increased from $3.17 to $3.33 based on PG&E 2024 recorded customer counts and consumption values. Further discussion on the value of service is described in Exhibit (PG&E-2), Chapter 1, Section C.

Using the latest public safety consequence model, the tranching deciles were refreshed as well as the safety risk attribute.

The outcomes have also been simplified. All outcomes are considered non-EPSS as well as non-ignition with one exception. The only ignition-related outcome category that remains is to capture the financial cost of replacing assets due to ignitions. Otherwise, all ignitions are represented in the WLDFR bowtie. An additional outcome attribute for major event day (MED) and non-MED was included since this is a differentiator in the consequence of a risk event.

Another significant change since RAMP is to account for the escalation of failures, as our replacement rate is lower than the failure rate. Historical outage data is used to evaluate the escalation rate and applied to the bowtie.

d. Changes in Risk Controls and Mitigations

Overall changes in risk controls and mitigations[10] include revised effectiveness values and workplans due to better available data. Failure rates have also been adjusted to consider specific asset conditions.

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10 See Attachment A at the end of this chapter for the Electric Distribution CBR comparison.

Foundational controls and foundational mitigations that are shared with DOVHD and WLDFR have been consolidated with the primary risk, which is WLDFR. For a complete history of foundational activities, controls, and mitigations for DOVHD since the 2024 RAMP Report, refer to Attachment B, Table 3-7 at the end of this chapter.

3. Failure of Electric Distribution Underground Assets

a. Risk Overview

The failure of distribution underground assets or remote operation functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy. Underground assets include radial and network primary distribution.

FIGURE 3-8
FAILURE OF ELECTRIC DISTRIBUTION UNDERGROUND ASSETS BOWTIE

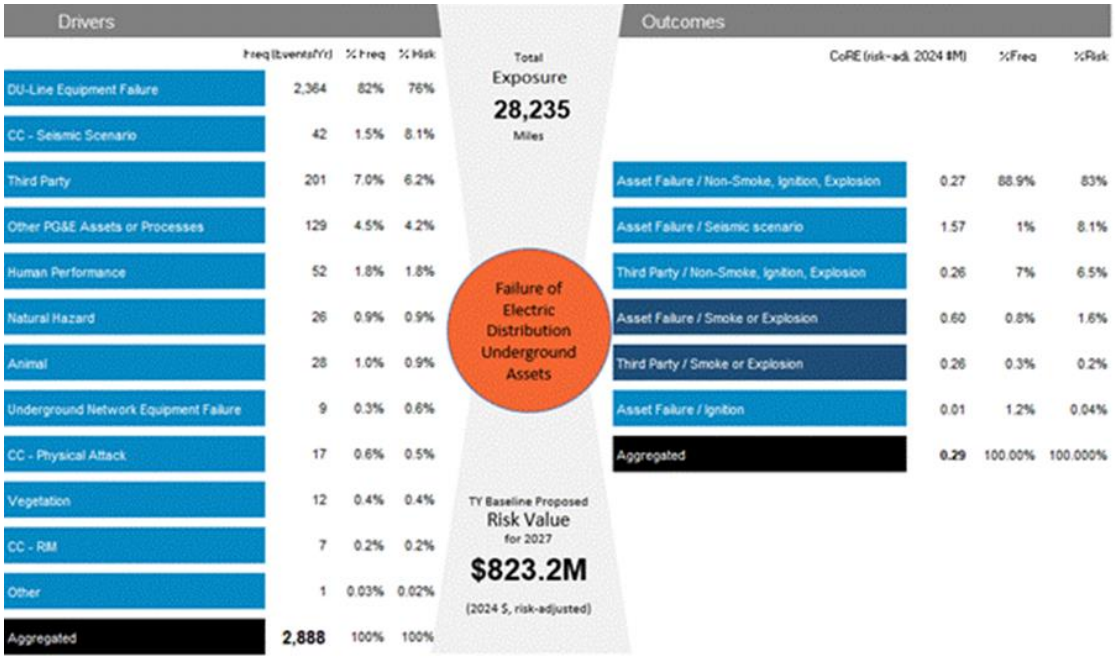

Figure 3-8 illustrates the Failure of Electric Distribution Underground Assets bowtie. There are 12 drivers, three are cross-cutting factors: distribution underground line equipment failure; seismic scenario (cross-cutting); third-party; other PG&E assets or processes; human performance; underground network equipment failure; animal; natural hazard; physical attack (cross-cutting); vegetation; records and

information management (cross-cutting); and other. The top driver, distribution underground equipment failure, accounts for over 80 percent of the frequency and about 75 percent of the risk. The cross-cutting factors are climate change, cyber attack, EP&R, IT asset failure, physical attack, records, and information management, and seismic. The risk exposure is based on the circuit miles of distribution underground radial and network system. The total exposure for this risk is 28,235 miles. There are four tranches: Radial vs Network System; Asset Health Need; Overloading Condition; and Historical Likelihood of Failure. With almost 90 percent, the most common outcome is asset failure with no smoke, ignition, or explosion. This single top outcome accounts for 83 percent of the risk.

b. Responding to Safety Policy Division (SPD) and Parties' Feedback on PG&E's 2024 RAMP Report

In October 2024, Cal Advocates, The Utility Reform Network (TURN), Energy Producers & Users Coalition and the Indicated Shippers (EPUC/IS), Mussey Grade Road Alliance (MGRA), and Small Business Utility Advocates (SBUA) provided informal comments on PG&E's 2024 RAMP Application (A.) 24-05-008. On November 8, 2024, the SPD issued its Staff Evaluation Report. PG&E appreciates SPD and parties' feedback and as shown agrees with many of the comments and recommendations received. A list of the feedback and PG&E's response to each item is provided in Exhibit (PG&E-2), WP 1-01_RAMP to GRC Feedback.

SPD recommended on breaking down the D1 risk driver based on equipment types. PG&E provided the sub-drivers in the 2024 RAMP, A.24-05-008, Exhibit (PG&E-4), WP EO-DUNGD-2_Bow tie. PG&E is also considering developing more granular visualizations based on specific sub-drivers like cable and transformer failures and considering enhancing the bowtie visual based on top sub-drivers in the 2028 RAMP application.

SPD also highlighted the reliance on lagging data sources and suggested incorporating more leading indicators to improve risk assessment accuracy. Progress has been made to incorporate a

leading indicator. From a bottoms up model[11] of DUNGD, the health need is included as part of the tranche. Health need is a result from inputs collected from each circuit regarding the age, tags, criteria standard, etc.

SPD pointed out that several control and mitigation programs had cost-benefit ratios (CBRs) of less than 1, suggesting opportunities for cost savings by limiting activities to tranches with higher CBRs. PG&E responds by providing more detailed justifications for programs with low CBRs and identifying compliance-related controls to aid the interpretation in the forecast chapters, Exhibit (PG&E-4), Chapter 4 through Chapter 23.

c. Risk Modeling Updates

Since RAMP, PG&E updated the historical frequency source data for network failure outage data from 2023 and 2024. A few historical data corrections were made based on expert input. Additionally, the safety monetized value has changed from $15.23 million to $16.2 million. This is the value of a statistical life from the Bureau of Labor Statistics, which has then been adjusted to California dollars. The value of service is calculated using the original Interruption Cost Estimate (ICE) calculator and has slightly increased from $3.17 to $3.33 based on PG&E 2024 recorded customer counts and consumption values. Further discussion on the value of service is described in Exhibit (PG&E-2), Chapter 1, Section C.

Another significant change since RAMP is to account for the escalation of failures, as our replacement rate is lower than the failure rate. Historical outage data is used to evaluate the escalation rate and applied to the bowtie.

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11 Exhibit (PG&E-4), WP EO-DUNGD-15_231110_Underground cable_asset health data request for risk.xlsx.

d. Changes in Risk Controls and Mitigations

Overall changes in risk controls and mitigations[12] include revised effectiveness values and workplans due to better available data. Based on historical data, network transformer and network protector replacement mitigation programs have been reclassified to the network component and transformer replacement control programs because the replacements maintain the level of baseline risk and do not reduce it. For a complete history of foundational activities, controls, and mitigations for DUNGD since the 2024 RAMP Report, refer to Attachment B, Table 3-8 at the end of this chapter. For a complete history of foundational activities, controls, and mitigations for DUNGD since the 2024 RAMP Report, refer to Attachment B, Table 3-10 at the end of this chapter.

4. Public Contact with Intact Energized Electrical Equipment

a. Risk Overview

Public Contact with Intact Energized Electrical Equipment is the risk of reportable serious injury or fatality to a third-party contractor or member of the public from an interaction with intact energized electrical equipment that did not originate from asset failure.

[12] See Attachment A at the end of this chapter for the Electric Distribution CBR comparison.

FIGURE 3-9
PUBLIC CONTACT WITH INTACT ENERGIZED ELECTRICAL EQUIPMENT BOWTIE

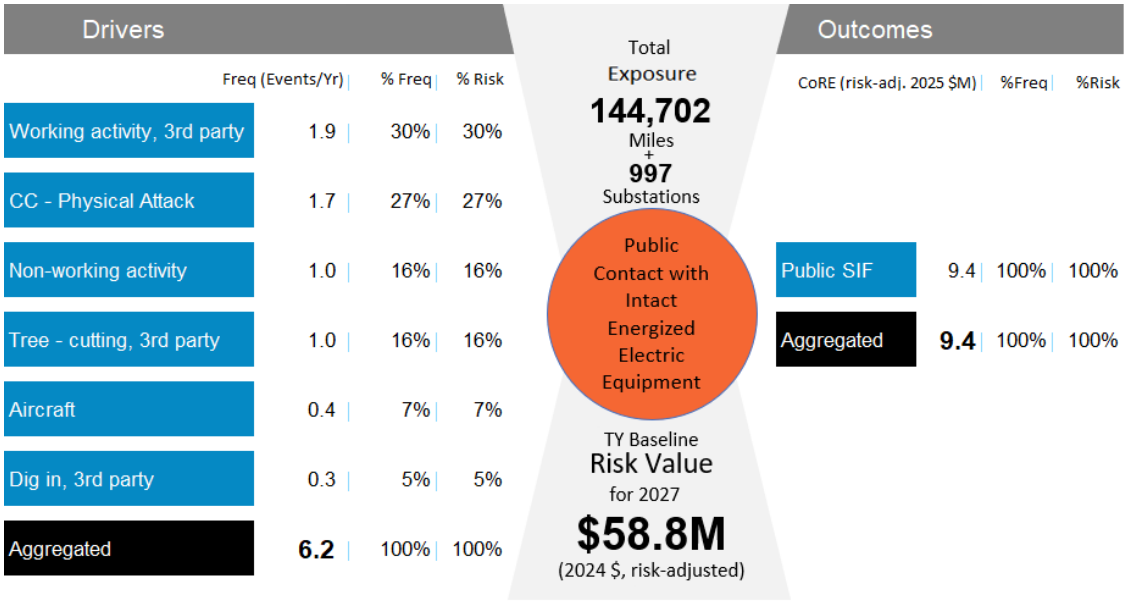


Figure 3-9 illustrates the Public Contact with Intact Energized Electrical Equipment bowtie. The 6 drivers include: third-party working activities; non-working activities; third party tree cutting services; aircraft contact; and third-party dig into PG&E electrical assets. The top four drivers, third-party working activities, physical attack, non-working activities, and third-party tree-cutting services account for almost 90 percent of the risk and frequency. This risk also involves a cross-cutting factor of Physical Attack that largely consists of vandalism and theft or attempted theft of PG&E assets.

Exposure to this risk is measured within the PG&E service territory and spans approximately 145,000 miles of Transmission and Distribution voltage conductors and 997 substations. There are four tranches to facilitate the quantitative risk analysis: Contact with Electric Distribution Overhead Assets; Contact with Electric Transmission Assets; Contact with Electric Distribution Underground Assets; and Contact with Electric Substation Assets.

b. Responding to Safety Policy Division (SPD) and Parties' Feedback on PG&E's 2024 RAMP Report

In October 2024, Cal Advocates, The Utility Reform Network (TURN), Energy Producers & Users Coalition and the Indicated Shippers (EPUC/IS), Mussey Grade Road Alliance (MGRA), and Small Business Utility Advocates (SBUA) provided informal comments on PG&E's 2024 RAMP Application (A.) 24-05-008. On November 8, 2024, the SPD issued its Staff Evaluation Report. A list of the feedback and PG&E's response to each item is provided in Exhibit (PG&E-2), WP 1-01_RAMP to GRC Feedback.xlsx.

SPD provided several recommendations to enhance the risk analysis, which includes using a longer historical data or employing methods like Bootstrap Resampling and Bayesian analysis to improve the accuracy of probability estimates. Additionally, SPD recommended augmenting quantitative data with qualitative insights to better understand patterns and trends, especially when dealing with small sample sizes. The feedback is appreciated and acknowledged for ongoing efforts to improve the risk model.

Furthermore, SPD emphasized the importance of focusing on mitigations and controls with higher cost-benefit ratios, such as Public Safety Awareness and Proximity Warning Alarms. Current initiatives are in these areas, including a pilot program for Proximity Warning Alarms planned for 2025. For more detailed information, refer to Exhibit (PG&E-4), Chapters 8 and 23 for Public Safety Awareness.

c. Risk Modeling Updates

Since RAMP, PG&E updated the historical frequency source data for serious injury and fatalities to include incidents from 2023 and 2024. Additionally, the safety monetized value has changed from $15.23 million to $16.2 million. This is the value of a statistical life from the Bureau of Labor Statistics, which has then been adjusted to California dollars.

d. Changes in Risk Controls and Mitigations

There were no major updates to the current risk controls and mitigations.[13] PG&E continues to explore tools that could improve efficiencies of its mitigation and control programs. As they materialize, mitigations that result will be identified. For a complete history of foundational activities, controls, and mitigations for PCEEE since the 2024 RAMP Report, refer to Attachment B, Table 3-9 at the end of this chapter.

D. Non-RAMP Risk Updates

PG&E has one electric distribution related risk not presented in the 2024 RAMP Report, which is Failure of Distribution Substation Assets. The section below describes the risk and major updates since the last GRC filing.

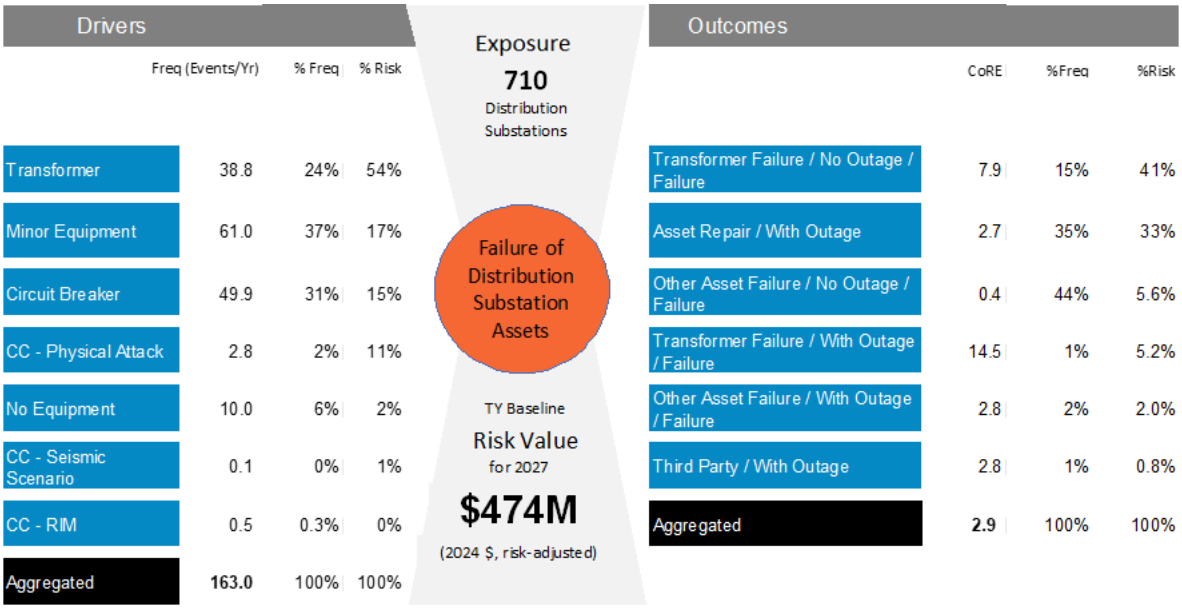
1. Failure of Distribution Substation Assets

a. Risk Overview

The failure of distribution substation assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, disruption of major generation sources, or inability to deliver energy. Figure 3-10 illustrates the Failure of Distribution Substation Assets bowtie.

[13] See Attachment A at the end of the chapter for Electric Distribution CBR comparison.

FIGURE 3-10
FAILURE OF DISTRIBUTION SUBSTATION ASSETS BOWTIE



There are some changes to the enterprise risk model since the last GRC filing. The drivers are re-organized to represent 4 asset types: transformer; minor equipment; circuit breaker and no equipment. Other drivers such as physical attack (cross-cutting); seismic (cross-cutting); and records and information management (cross-cutting) remain from the previous Bowtie. The original drivers such as Human Performance, Natural Hazard are downgraded as sub-drivers.

The cross-cutting factors that impact the Failure of Electric Distribution Substation Assets risk are the following: Climate Change, Cyber Attack, EP&R, Physical Attack, Records, and Information Management, Seismic, and Skilled and Qualified Workforce.

The asset family for distribution substation has 710 substations. Each substation transforms high voltage electricity from PG&E's electric transmission system to lower voltage for delivery to PG&E's customers. Similar to the driver change, tranches to this risk (excluding the seismic risk) have changed from 20 total unique combinations in the categories of HFTD, criticality, and asset type to 16 unique combinations (4 security tiers and 4 asset types). Outcomes have also been updated from 5 to 6 to account for asset type, repair versus replacement, and with an outage or without an outage.

Other major updates include an integration of failure data with zero outage Customer Minutes Interrupted (CMI); risk due to a lack of redundancy within the network; incorporation of forecasted probability of transformer failure to serve as a leading indicator. Specific bowtie values can be found in workpaper, Exhibit (PG&E4), WP EO-DSBSN-2_Bow tie.xlsm.

b. Proposed Risk Controls and Mitigations

Since the last GRC filing, most of the maintenance and diagnostic tests have been classified as foundational control or mitigation programs. The replacement asset equipment control programs are now based on major asset types (breaker and switch; transformer; and other equipment). PG&E has added one new mitigation program, Substation Distribution – Security Enhancements and one new control program, Substation Distribution - Emergency Mobile Transformers. These controls and mitigation are described in Chapter 18 – Substation Asset Management, which also includes any activities that are compliance-related.

The Substation Distribution – Defensible Spaces risk mitigation shows a significantly higher CBR value when compared to the 2024 RAMP Report. The update included a change from applying the program effectiveness on the frequency on the vegetation contact driver to the outcomes for all fire types. As a result, the risk reduction increased significantly and therefore increased the CBR value.

For a complete history of foundational activities, controls, and mitigations for DSBSN since the 2024 RAMP Report, refer to Attachment B, Table 3-10 at the end of this chapter.

c. Risk-Based Decision-Making Framework, Step 3 Supplemental Analysis

Per the Risk-Based Decision-Making Framework (RDF) requirements in D.22-12-027, any risk control or mitigation program included in PG&E's 2027 GRC Application that was not addressed in PG&E's 2024 RAMP and meets additional criteria is subject to Step 3

Supplemental Analysis.[14] Risk controls and mitigations for Failure of Electric Distribution Substation Assets risk are subject to Step 3 Supplemental Analysis. Based on the outcome of the analysis, PG&E is required to provide CBRs for the following control programs:

- DSBSN-C009: Substation Distribution – Emergency Maintenance;
- DSBSN-C010: Substation Distribution – Replacement – Transformer;
- DSBSN-C011: Substation Distribution – Replacement – Breaker and Switch;
- DSBSN-C013: Substation Distribution – Emergency Replacement; and
- DSBSN-M004: Substation Distribution – Security Enhancements.

The results of the Step 3 analysis are included in workpapers[15] along with the CBRs for these control programs.

E. Conclusion

PG&E's risk management strategies are robust, data-driven and continue to evolve based on learnings and feedback. Our experienced team employs industry best practices, ensuring accurate and actionable risk assessments that are part of our continuous improvement commitment. These risk assessments inform our risk-based portfolio prioritization framework for our investment plan proposed in this exhibit, and reinforces the necessity of continued investment to maintain and improve the safety and reliability of our electric distribution system.

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14 D.22-12-027, Appendix A, p. A-17, No. 28.

15 See Exhibit (PG&E-4), WP 3-25 for details.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ATTACHMENT A

LIST OF FOUNDATIONAL ACTIVITIES, CONTROLS AND MITIGATIONS FOR RAMP AND NON RAMP RISKS

Table 3-3: FOUNDATIONAL ACTIVITIES, CONTROLS AND MITIGATIONS FOR RAMP AND NON-RAMP RISKS

						Cost Benefit Ratios	
Line No.	Risk Program ID	Risk Program Name	Risk Program Type	MWC/MAT	Exhibit 4 Chapter No.	2027 GRC CBR	2024 RAMP CBR
1	DOVHD-C008	Annual Protection Reviews	Foundational	FZA	9	Foundational	Foundational
2	DSBSN-C003	Substation Distribution Patrols and Inspections	Foundational	GCD	18	Foundational	N/A
3	DSBSN-C004	Substation Distribution - Maintenance (Supportive Activities)	Foundational	GC1	18	Foundational	N/A
4	DSBSN-C005	Substation Distribution - Maintenance (Transformer)	Foundational	GCA, GCO	18	Foundational	N/A
5	DSBSN-C006	Substation Distribution - Maintenance (Circuit Breaker and Switch)	Foundational	GCB, GCI, GCM, GCS, GCV	18	Foundational	N/A
6	DSBSN-C007	Substation Distribution - Maintenance (Other Equipment)	Foundational	GCC, GCE, GCF, GCW	18	Foundational	N/A
7	DSBSN-C016	Substation Distribution - Line Work Support	Foundational	48L	18	Foundational	N/A
8	DSBSN-C017	Substation Distribution - SCADA/RTU Replace	Foundational	09B	19	Foundational	N/A
9	DUNGD-C001	UG Patrols	Foundational	BFD	14	Foundational	Foundational
10	DUNGD-C008	UG Transformers Temperature Sensor	Foundational	56T	16	Foundational	Foundational
11	DUNGD-C010	UG Inspections	Foundational	BFE	14	Foundational	Foundational
12	DUNGD-M003	Network Installation of SCADA Equipment for Safety Monitoring	Foundational	2CE	16	Foundational	Foundational
13	WLDFR-C005	Distribution Overhead Inspections - Ground	Foundational	BFB	14	Foundational	Foundational
14	WLDFR-C006	Distribution Overhead Inspections - Infrared	Foundational	BFC	14	Foundational	Foundational
15	WLDFR-C007	Distribution Overhead Inspections - Aerial	Foundational	BF1	14	Foundational	Foundational
16	WLDFR-C011	Intrusive Wood Pole Inspection	Foundational	07R, GAA	15	Foundational	Foundational
17	WLDFR-C013	Patrols - Distribution Overhead	Foundational	BFA	14	Foundational	Foundational
18	WLDFR-C077	Vegetation Management Data and Technology - Distribution	Foundational	HN#	8	Foundational	Foundational
19	WLDFR-C081	Vegetation Management Document Governance (Standards, Procedures) and Training	Foundational	HN#, IGI	8	Foundational	N/A
20	WLDFR-C082	VM Support - Routine Patrol	Foundational	HN#	8	Foundational	N/A
21	WLDFR-C083	VM Wood Management - Routine Patrol	Foundational	HNA	8	Foundational	N/A
22	WLDFR-C084	VM Support - Second Patrol	Foundational	IGI	8	Foundational	N/A
23	WLDFR-C085	VM Wood Management - Second Patrol	Foundational	IGI	8	Foundational	N/A
24	WLDFR-C086	Situational Awareness and Forecasting Initiatives - Satellite Fire Detection	Foundational	WFM	5	Foundational	Foundational
25	WLDFR-C087	Situational Awareness and Forecasting Initiatives - Fire Potential Index O&M	Foundational	WFM	5	Foundational	N/A
26	WLDFR-C088	Situational Awareness and Forecasting Initiatives - Weather Station Expense	Foundational	WFW	5	Foundational	N/A
27	WLDFR-C089	Situational Awareness and Forecasting Initiatives - Meteorology IT support Expense	Foundational	WFM	5	Foundational	N/A
28	WLDFR-M005	Situational Awareness and Forecasting Initiatives - Numerical Weather Prediction and Weather Stations	Foundational	WFM	5	Foundational	Foundational
29	WLDFR-M006	Situational Awareness and Forecasting Initiatives - Cameras	Foundational	WFC	5	Foundational	Foundational
				21#, AB#, AB6, AB6, AB6,	4, 6, 20, 21,		
30	WLDFR-M009	Wildfire Strategy & Preparation Support	Foundational	BAF	23	Foundational	N/A
31	WLDFR-M038	Substation Distribution - Supplemental Maintenance	Foundational	GC5	18	Foundational	N/A
32	WLDFR-M043	Situational Awareness and Forecasting Initiatives - Satellite Data Analysis	Foundational	AB6	5	Foundational	N/A
33	WLDFR-M044	Situational Awareness and Forecasting Initiatives - EFD	Foundational	3UE	5	Foundational	Foundational
34	WLDFR-M045	Situational Awareness and Forecasting Initiatives - DFA	Foundational	3UD	5	Foundational	Foundational
35	WLDFR-M046	Situational Awareness and Forecasting Initiatives - Line Sensors	Foundational	3UL, 3UL	5	Foundational	Foundational
36	WLDFR-M047	VM Support - Mitigations	Foundational	IGJ	8	Foundational	N/A
37	WLDFR-M048	VM Wood Management - Mitigations	Foundational	IGJ	8	Foundational	N/A
38	WLDFR-M049	Situational Awareness and Forecasting Initiatives - Asset Health & Performance Center Expense	Foundational	FZA	5	Foundational	N/A
39	WLDFR-M050	Situational Awareness and Forecasting Initiatives - Advanced Fire Modeling	Foundational	WFM	5	Foundational	N/A
40	WLDFR-M051	Situational Awareness and Forecasting Initiatives - Research and Academic Partnerships	Foundational	WFM	5	Foundational	N/A
41	WLDFR-M052	Situational Awareness and Forecasting Initiatives - Weather Station Capital	Foundational	21B, 21B	5	Foundational	N/A
42	WLDFR-M053	Situational Awareness and Forecasting Initiatives - Meteorology IT support Capital	Foundational	21A	5	Foundational	N/A
43	WLDFR-M054	System Hardening Program Support	Foundational	AB#	7	Foundational	N/A
44	WLDFR-M057	Wildfire IT Work	Foundational	2F#, 2FA, IG#	21	Foundational	N/A
45	WLDFR-M059	Integrated Planning Undergrounding Tool Development (IPUTD)	Foundational	21#, GEP	20, 23	Foundational	N/A
46	WPSPS-M007	Support Labor (PSPS Customer Resiliency NonEvent)	Foundational	IG#	6	Foundational	N/A
47	DOVHD-C001, WLDFR-C001	VM Distribution - Routine Patrols	Control	HNA	8	2.4	3.2
48	DOVHD-C002, WLDFR-C002	VM Distribution - Second Patrols	Control	IGI	8	3.1	0.8
49	DOVHD-C009, WLDFR-C009	Overloaded Transformers Replacement	Control	06B	9	0.3	0.2
50	DOVHD-C014, WLDFR-C014	Pole Replacement	Control	07D	15	0.5	1.0
51	DOVHD-C015, WLDFR-C015	Overloaded Pole Replacements	Control	07O	15	0.1	0.02
52	DOVHD-C016, WLDFR-C016	Animal Abatement [2AB,KAC]	Control	2AB, KAC	15	18.8	18.0
53	DOVHD-C017, WLDFR-C017	Animal Abatement [2AC,KAD]	Control	2AC, KAD	15	49.8	117
54	DOVHD-C018, WLDFR-C018	Pole Restoration	Control	07R	15	0.6	0.8
55	DOVHD-C019, WLDFR-C019	Emergency Distribution Replacements [17B]	Control	17B	11	51.9	111
56	DOVHD-C020, WLDFR-C020	Distribution Replacements [2AA]	Control	2AA	15	4.6	2.8
57	DOVHD-C021, WLDFR-C021	Distribution Maintenance Replacements [KAA]	Control	KAA	15	13.8	8.5
58	DOVHD-C022, WLDFR-C022	Distribution Maintenance Replacements [KAQ]	Control	KAQ	15	0.4	0.2
59	DOVHD-C024, DUNGD-C017, PCEEE-C002	Public Safety Awareness	Control	AB#, HN#	8, 23	27.2	7.6
60	DOVHD-C025, WLDFR-C080	Pole Clearing - Routine	Control	HNA	8	2.0	N/A
61	DSBSN-C008	Substation Distribution - Corrective Maintenance	Control	GCJ	18	Step 3 Exempt	0
62	DSBSN-C009	Substation Distribution - Emergency Maintenance	Control	GC2	18	29.4	N/A
63	DSBSN-C010	Substation Distribution - Replacement (Transformer)	Control	54A	18	1.4	N/A
64	DSBSN-C011	Substation Distribution - Replacement (Breaker and Switch)	Control	48D, 48E, 48F, 49E	18	1.2	N/A
65	DSBSN-C012	Substation Distribution - Replacement (Other Equipment)	Control	48A	18	Step 3 Exempt	0
66	DSBSN-C013	Substation Distribution - Emergency Replacement	Control	59A	18	1.1	N/A
67	DSBSN-C015	Substation Distribution - Emergency Mobile Transformers	Control	54A, 59A	18	Step 3 Exempt	0
68	DUNGD-C002	Underground Notifications	Control	KBA	16	3.9	6.5
69	DUNGD-C003	UG General Equipment Maintenance and Replacement	Control	2BA	16	2.0	1.8
70	DUNGD-C006	Primary Cable Replacement	Control	56A	16	1.3	0.8
71	DUNGD-C007	LBOR Switch Replacement	Control	56S	16	0.5	0.9
72	DUNGD-C011	Network Cable Replacement	Control	56N	16	1.2	1.1
73	DUNGD-C012	Network Maintenance and Corrective Work [Transformer Maintenance and Testing]	Control	KCD	16	3.4	5.1
74	DUNGD-C014	Network Component (Transformer, Protector) Replacements - Condition Based [Transformer]	Control	2CC	16	1.2	0.8
75	DUNGD-C015	Network Component (Transformer, Protector) Replacements - Condition Based [Protector]	Control	2CC	16	1.4	0.1
76	DUNGD-C016, LOCDM-C017, PCEEE-C001	Locate and Mark - Distribution	Control	DFA - GD, DFB - GD, DF#, FH	8	1.5	0.5
77	DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening [Overhead]	Mitigation	08W, 3UG	7	13.3	17.8
78	DOVHD-M006	Grasshopper and KPF Switch Replacement	Mitigation	08S	17	2.0	0.05
79	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	Mitigation	08W, 3UG	7	6.8	7.9
80	DOVHD-M023, WLDFR-M023	Backlog Open Tag Reduction - Distribution (Pole Backlog)	Mitigation	07D	15	0.4	0.1
81	DOVHD-M024, WLDFR-M024	Backlog Open Tag Reduction - Distribution (Capital) [2AA]	Mitigation	2AA	15	2.1	0.8
82	DOVHD-M025, WLDFR-M025	Backlog Open Tag Reduction - Distribution (Expense) [KAA]	Mitigation	KAA	15	18.4	6.6
83	DOVHD-M026, WLDFR-M026	Pole Programs - Replace Tree Attachments	Mitigation	07C	15	0.9	0.04
84	DOVHD-M027, WLDFR-M027	Vegetation Control/Right of Way Clearing	Mitigation	HNA	8	4	2.3
85	DOVHD-M028, WLDFR-M028	VM Distribution - Targeted Inspection	Mitigation	IGJ	8	6.5	5.4
86	DOVHD-M029, WLDFR-M029	VM for Operational Mitigations (VMOM)	Mitigation	IGJ	8	12.9	5.1
87	DOVHD-M030, WLDFR-M030	VM Distribution - Tree Removal Inventory	Mitigation	IGJ	8	3.9	5.0
88	DOVHD-M031, WEPSS-M011, WPSPS-M003	Portable Battery	Mitigation	IG#	6	0.4	4.3

Table 3-3: FOUNDATIONAL ACTIVITIES, CONTROLS AND MITIGATIONS FOR RAMP AND NON-RAMP RISKS

						Cost Benefit Ratios	
Line No.	Risk Program ID	Risk Program Name	Risk Program Type	MWC/MAT	Exhibit 4 Chapter No.	2027 GRC CBR	2024 RAMP CBR
89	DOVHD-M032, WEPSS-M012, WPSPS-M004	Permanent Battery	Mitigation	IG#	6	4.2	13.7
90	DOVHD-M033, WEPSS-M013, WPSPS-M005	RSI Battery	Mitigation	IG#	6	1.7	4.1
91	DOVHD-M034	OH Fuses Install/Replace	Mitigation	49C	17	11.9	8.7
92	DOVHD-M035	Overhead Conductor Replacement	Mitigation	08J	17	0.3	0.001
93	DOVHD-M039, WEPSS-M017, WPSPS-M008	Generator and Battery Rebate Program (GBRP)	Mitigation	IG#	6	23.6	N/A
94	DOVHD-M040, WEPSS-M018, WPSPS-M009	BTM Capital Battery Program	Mitigation	21#	6	1.5	N/A
95	DOVHD-M043	Reliability Enhancement	Mitigation	49X	17	1.4	N/A
96	DSBSN-M004, PCEEE-M005	Substation Distribution - Security Enhancements	Mitigation	58S	18	1.1	N/A
97	DUNGD-M002	Venting Manhole Cover Replacements	Mitigation	2CD	16	0.5	N/A
98	WLDFR-M001	PSPS	Mitigation	WFN, WFP	6	25.3	42.8
99	WLDFR-M011	System Hardening [Remote Grid]	Mitigation	08W, AB#	7	14.0	20.9
100	WLDFR-M020	EPSS	Mitigation	49#, 49B, 49D, 49E, 49G, 63C, BAF, BAH, BFJ, BHE, DD#, FZA, FZE, GC2, HGD,	6	33.8	51.9
101	WLDFR-M037	Substation Distribution - Defensible Spaces	Mitigation	GCG	18	16.1	0.0002
102	WLDFR-M041	Utility Defensible Space - Distribution	Mitigation	IGJ	8	2.7	N/A
103	WLDFR-M056	Wildfire Resilience Partnerships – Fuels Treatment	Mitigation	AB#	4	27.5	N/A
104	WLDFR-M058	Breakaway Connectors Replacement	Mitigation	08J	17	4.7	N/A
105	WPSPS-M006	Temporary Generation	Mitigation	IG#	6	5.7	2.3
106	WPSPS-M011	PSPS Granular Sectionalizing	Mitigation	3UP	6	Step 3 Exempt	N/A
107	WLDFR-M008	Safety Infrastructure Protection Teams	Mitigation	21A, WFS	Exhibit 7	1.9	5.7
108	WLDFR-C091	Wildfire Helicopter Assistance	Control	TA#	Exhibit 7	Step 3 Exempt	N/A

Notes:

1. ***Foundational*** indicates this program is a foundational activity. The Commission defines foundational programs and/or activities as initiatives that support or enable two or more mitigation programs or two or more risks but do not directly reduce the consequences or the likelihood of risk events. Per D.21-11-009, CBRs for foundational activities are not required. However, forecast costs of foundational activities must be included in the CBR calculations for the control and mitigation programs that the foundational activities enable, subject to minimum cost thresholds. For more information on this, please see PG&E's 2024 RAMP, Exhibit (PG&E-2), Ch. 2, Section 4.g. For a list of Foundational Activities and their 2027 GRC cost forecasts, please see Exhibit (PG&E-3), WP 3-24.

2. ***Step 3 Exempt*** indicates this program is exempt from Step 3 Supplemental Analysis in the GRC and does not require a CBR. For more information on Step 3 Supplemental Analysis, see D.22-12-027, Appendix A, p. A-17, No. 28. For specific details on PG&E's designation of Step 3 exempt programs, please see Exhibit (PG&E-3), WP 3-36, -37, -38, -39, -40, and -41.

3. N/A indicates this program was not presented in PG&E's 2024 RAMP.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 3

ATTACHMENT B

2024 RAMP TO 2027 GRC RISK PROGRAM INDEX

Table 3-4: 2024 RAMP to 2027 GRC Risk Program Index for Wildfire / WLDFR

WLDFR Controls						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
1	WLDFR-C001	VM Distribution - Routine Patrols		X	X	Includes the scope of Routine Patrols, Targeted Inspection, and Tree Removal Inventory
2	WLDFR-C002	VM Distribution - Second Patrols		X	X	Includes the scope of Second Patrols and VMOM
3	WLDFR-C005	Distribution OH Inspections - Ground	X	X	X	
4	WLDFR-C006	Distribution OH Inspections - IR	X	X	X	
5	WLDFR-C007	Distribution OH Inspections - Aerial	X	X	X	
6	WLDFR-C009	Overloaded Transformers Replacement		X	X	
7	WLDFR-C010	Situational Awareness and Forecasting Initiatives - Early Fault Detection (EFD)	X	X		Converted from Foundational Control WLDFR-C010 to Foundational Mitigation WLDFR-M044
8	WLDFR-C011	Intrusive Wood Pole Inspection Program	X	X	X	
9	WLDFR-C012	Situational Awareness and Forecasting Initiatives - Distribution Fault Anticipation (DFA)	X	X		Converted from Foundational Control WLDFR-C012 to Foundational Mitigation WLDFR-M045
10	WLDFR-C013	Patrols - Distribution OH	X	X	X	
11	WLDFR-C014	Pole Replacement		X	X	
12	WLDFR-C015	Overloaded Pole Replacements		X	X	
13	WLDFR-C016	Animal Abatement [2AB,KAC]		X	X	
14	WLDFR-C017	Animal Abatement [2AC,KAD]		X	X	
15	WLDFR-C018	Pole Restoration Program		X	X	
16	WLDFR-C019	Emergency Distribution Replacements [17B]		X	X	
17	WLDFR-C020	Distribution Replacements [2AA]		X	X	Name change from "Distribution Steady State Proactive Replacements [2AA]"
18	WLDFR-C021	Distribution Maintenance Replacements [KAA]		X	X	Name change from "Distribution Steady State Maintenance Replacements [KAA]"
19	WLDFR-C022	Distribution Maintenance Replacements [KAQ]		X	X	Name change from "Distribution Steady State Maintenance Replacements [KAQ]"
20	WLDFR-C023	Situational Awareness and Forecasting Initiatives - Line Sensors	X	X		Converted from Foundational Control WLDFR-C023 to Foundational Mitigation WLDFR-M046
21	WLDFR-C025	Transmission Inspections IR	X	X		Transmission is out of scope for 2027 GRC
22	WLDFR-C028	Transmission Inspections Climbing	X	X		Transmission is out of scope for 2027 GRC
23	WLDFR-C029	Transmission Inspections Aerial	X	X		Transmission is out of scope for 2027 GRC

Table 3-4: 2024 RAMP to 2027 GRC Risk Program Index for Wildfire / WLDFR

WLDFR Controls						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
24	WLDFR-C030	Transmission Inspections Ground	X	X		Transmission is out of scope for 2027 GRC
25	WLDFR-C031	Capital Transmission Steady State Pole Replacement		X		Transmission is out of scope for 2027 GRC
26	WLDFR-C032	Capital Transmission Steady State Replacement		X		Transmission is out of scope for 2027 GRC
27	WLDFR-C033	Emergency Transmission Capital Replacement		X		Transmission is out of scope for 2027 GRC
28	WLDFR-C034	Expense Transmission Steady State Replacement		X		Transmission is out of scope for 2027 GRC
29	WLDFR-C035	Emergency Transmission Expense Replacement		X		Transmission is out of scope for 2027 GRC
30	WLDFR-C036	Routine Patrols Veg - Transmission		X		Transmission is out of scope for 2027 GRC
31	WLDFR-C037	Second Patrols Veg - Transmission		X		Transmission is out of scope for 2027 GRC
32	WLDFR-C077	Vegetation Management Data and Technology - Distribution	X	X	X	Name change from "OneVeg Program"
33	WLDFR-C078	Transmission Vegetation LiDAR	X	X		Transmission is out of scope for 2027 GRC
34	WLDFR-C080	Pole Clearing - Routine			X	
35	WLDFR-C081	Vegetation Management Document Governance (Standards, Procedures) and Training	X		X	Also supports DOVHD risk
36	WLDFR-C082	VM Support - Routine Patrol	X		X	Also supports DOVHD risk
37	WLDFR-C083	VM Wood Management - Routine Patrol	X		X	Also supports DOVHD risk
38	WLDFR-C084	VM Support - Second Patrol	X		X	Also supports DOVHD risk
39	WLDFR-C085	VM Wood Management - Second Patrol	X		X	Also supports DOVHD risk
40	WLDFR-C086	Situational Awareness and Forecasting Initiatives - Satellite Fire Detection	X		X	Converted from Foundational Mitigation WLDFR-M007 to Foundational Control WLDFR-C086
41	WLDFR-C087	Situational Awareness and Forecasting Initiatives - Fire Potential Index O&M	X		X	
42	WLDFR-C088	Situational Awareness and Forecasting Initiatives - Weather Station Expense	X		X	
43	WLDFR-C089	Situational Awareness and Forecasting Initiatives - Meteorology IT support Expense	X		X	
44	WLDFR-C090	Vegetation Management Data and Technology - Transmission	X			Transmission is out of scope for 2027 GRC
45	WLDFR-C091	Wildfire Helicopter Assistance			X	Step 3 Exempt

Table 3-4: 2024 RAMP to 2027 GRC Risk Program Index for Wildfire / WLDFR

WLDFR Controls						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes

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Table 3-4: 2024 RAMP to 2027 GRC Risk Program Index for Wildfire / WLDFR

WLDFR Mitigations						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
1	WLDFR-M001	PSPS		X	X	
2	WLDFR-M002	System Hardening [Overhead]		X	X	
3	WLDFR-M003	Non-Exempt Surge Arrester Replacement		X		Program retired after 2023
4	WLDFR-M004	Expulsion Fuse Replacement		X	X	No CBR provided. Program will retire after 2025.
5	WLDFR-M005	Situational Awareness - Numerical Weather Prediction and Weather Stations	X	X	X	
6	WLDFR-M006	Situational Awareness and Forecasting Initiatives - Cameras	X	X	X	
7	WLDFR-M007	Situational Awareness and Forecasting Initiatives - Satellite Fire Detection	X	X		Converted from Foundational Mitigation WLDFR-M007 to Foundational Control WLDFR-C086
8	WLDFR-M008	Safety Infrastructure Protection Teams		X	X	Forecasted in Exhibit 7
9	WLDFR-M009	Wildfire Strategy & Preparation Support	X		X	Name change from "Community Wildfire Safety Program Project Management Office"
10	WLDFR-M010	Additional System Automation and Protection - FuseSaver		X		Program retired
11	WLDFR-M011	System Hardening [Remote Grid]		X	X	
12	WLDFR-M014	Butte County Rebuild		X	X	No CBR provided. Program will retire after 2026. This funding is not included in the 2027 GRC.
13	WLDFR-M020	EPSS		X	X	
14	WLDFR-M022	System Hardening [UG]		X	X	
15	WLDFR-M023	Open Tag Reduction - Distribution (Pole Backlog)		X	X	
16	WLDFR-M024	Backlog Open Tag Reduction - Distribution (Capital) [2AA]		X	X	
17	WLDFR-M025	Backlog Open Tag Reduction - Distribution (Expense) [KAA]		X	X	
18	WLDFR-M026	Pole Programs - Replace Tree Attachments		X	X	
19	WLDFR-M027	Vegetation Control/Right of Way Clearing		X	X	Name change from "Pole Clearing"
20	WLDFR-M028	VM Distribution - Targeted Inspection		X	X	Name change from "VM Distribution - Focused Tree Inspections"
21	WLDFR-M029	VM for Operational Mitigations (VMOM)		X	X	Name change from "VM Distribution - Operational Improvements"
22	WLDFR-M030	VM - Tree Removal Inventory (TRI)		X	X	
23	WLDFR-M032	Traditional OH Hardening - Line Removal		X		Program retired

Table 3-4: 2024 RAMP to 2027 GRC Risk Program Index for Wildfire / WLDFR

WLDFR Mitigations						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
24	WLDFR-M033	Traditional OH Hardening - Shunt Splices		X		Program retired
25	WLDFR-M034	HFTD/HFRA Open Tag Reduction - Transmission		X		Transmission is out of scope for 2027 GRC
26	WLDFR-M035	Integrated Vegetation Management - Transmission		X		Transmission is out of scope for 2027 GRC
27	WLDFR-M036	Traditional OH Hardening - System Hardening Transmission		X		Transmission is out of scope for 2027 GRC
28	WLDFR-M037	Substation Distribution - Defensible Spaces		X	X	
29	WLDFR-M038	Substation Distribution - Supplemental Maintenance	X		X	
30	WLDFR-M039	Substation Transmission - Defensible Spaces		X		Transmission is out of scope for 2027 GRC
31	WLDFR-M040	Substation Transmission - Supplemental Maintenance	X			Transmission is out of scope for 2027 GRC
32	WLDFR-M041	Utility Defensible Space - Distribution			X	
33	WLDFR-M043	Situational Awareness and Forecasting Initiatives - Satellite Data Analysis	X		X	
34	WLDFR-M044	Situational Awareness and Forecasting Initiatives - EFD	X		X	Converted from Foundational Control WLDFR-C010 to Foundational Mitigation WLDFR-M044
35	WLDFR-M045	Situational Awareness and Forecasting Initiatives - DFA	X		X	Converted from Foundational Control WLDFR-C012 to Foundational Mitigation WLDFR-M045
36	WLDFR-M046	Situational Awareness and Forecasting Initiatives - Line Sensors	X		X	Converted from Foundational Control WLDFR-C023 to Foundational Mitigation WLDFR-M046
37	WLDFR-M047	VM Support - Mitigations	X		X	Also supports DOVHD and WEPSS risks
38	WLDFR-M048	VM Wood Management - Mitigations	X		X	Also supports DOVHD and WEPSS risks
39	WLDFR-M049	Situational Awareness and Forecasting Initiatives - Asset Health & Performance Center Expense	X		X	
40	WLDFR-M050	Situational Awareness and Forecasting Initiatives - Advanced Fire Modeling	X		X	
41	WLDFR-M051	Situational Awareness and Forecasting Initiatives - Research and Academic Partnerships (Foundational)	X		X	
42	WLDFR-M052	Situational Awareness and Forecasting Initiatives - Weather Station Capital	X		X	
43	WLDFR-M053	Situational Awareness and Forecasting Initiatives - Meteorology IT support Capital	X		X	
44	WLDFR-M054	System Hardening Program Support	X		X	Also supports DOVHD, PCEEE, and WEPSS risks
45	WLDFR-M056	Wildfire Resilience Partnerships - Fuels Treatment			X	
46	WLDFR-M057	Wildfire IT Work	X		X	

Table 3-4: 2024 RAMP to 2027 GRC Risk Program Index for Wildfire / WLDFR

WLDFR Mitigations						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
47	WLDFR-M058	Breakaway Connectors Replacement			X	
48	WLDFR-M059	Integrated Planning Undergrounding Tool Development (IPUTD)	X		X	

Table 3-5: 2024 RAMP to 2027 GRC Risk Program Index for Wildfire with PSPS / WPSPS

WPSPS Mitigations						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
1	WPSPS-M001	System Hardening [UG]		X	X	
2	WPSPS-M002	PSPS MSO Sectionalizer		X		Program retired
3	WPSPS-M003	Portable Battery		X	X	
4	WPSPS-M004	Permanent Battery		X	X	
5	WPSPS-M005	RSI Battery		X	X	
6	WPSPS-M006	Temporary Generation		X	X	
7	WPSPS-M007	Support Labor (PSPS Customer Resiliency NonEvent)	X		X	Also supports DOVHD and WEPSS risks
8	WPSPS-M008	Generator and Battery Rebate Program (GBRP)			X	
9	WPSPS-M009	BTM Capital Battery Program			X	
10	WPSPS-M010	Backup Power Transfer Meter program			X	No CBR provided. Benefits are not quantifiable.
11	WPSPS-M011	PSPS Granular Sectionalizing			X	Step 3 Exempt

Table 3-6: 2024 RAMP to 2027 GRC Risk Program Index for Wildfire with EPSS / WEPSS

WEPSS Mitigations						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
1	WEPSS-M001	System Hardening [Overhead]			X	
2	WEPSS-M002	Butte County Rebuild			X	No CBR provided. Program will retire after 2026. Mitigation is out of scope for 2027 GRC.
3	WEPSS-M003	System Hardening [Underground]			X	
4	WEPSS-M004	Backlog Open Tag Reduction - Distribution (Pole Backlog)			X	
5	WEPSS-M005	Backlog Open Tag Reduction - Distribution (Capital) [2AA]			X	
6	WEPSS-M006	Backlog Open Tag Reduction - Distribution (Expense) [KAA]			X	
7	WEPSS-M007	Vegetation Control/Right of Way Clearing			X	Name change from "Pole Clearing"
8	WEPSS-M008	VM Distribution - Targeted Inspection			X	Name change from "VM Distribution - Focused Tree Inspections"
9	WEPSS-M009	VM for Operational Mitigations (VMOM)		X	X	Name change from "VM Distribution - Operational Improvements"
10	WEPSS-M010	VM Distribution - Tree Removal Inventory			X	
11	WEPSS-M011	Portable Battery		X	X	
12	WEPSS-M012	Permanent Battery		X	X	
13	WEPSS-M013	RSI Battery		X	X	
14	WEPSS-M017	Generator and Battery Rebate Program (GBRP)			X	
15	WEPSS-M018	BTM Capital Battery Program			X	
16	WEPSS-M019	Backup Power Transfer Meter program			X	No CBR provided. Benefits are not quantifiable.
17	WEPSS-M022	Pole Programs - Replace Tree Attachments			X	

Table 3-7: 2024 RAMP to 2027 GRC Risk Program Index for Failure of Electric Distribution Overhead Assets / DOVHD

DOVHD Controls						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
1	DOVHD-C001	VM Distribution - Routine Patrols		X	X	Includes the scope of Routine Patrols, Targeted Inspection, and Tree Removal Inventory
2	DOVHD-C002	VM Distribution - Second Patrols		X	X	Includes the scope of Second Patrols and VMOM
3	DOVHD-C005	Distribution Overhead Inspections - Ground	X	X		Retired duplicate foundational program code. Only keeping WLDFR-C005. Program continues to support both risks.
4	DOVHD-C006	Distribution Overhead Inspections - Infrared	X	X		Retired duplicate foundational program code. Only keeping WLDFR-C006. Program continues to support both risks.
5	DOVHD-C007	Distribution Overhead Inspections - Aerial	X	X		Retired duplicate foundational program code. Only keeping WLDFR-C007. Program continues to support both risks.
6	DOVHD-C008	Annual Protection Reviews	X	X	X	
7	DOVHD-C009	Overloaded Transformers Replacement		X	X	
8	DOVHD-C011	Intrusive Wood Pole Inspection Program	X	X		Retired duplicate foundational program code. Only keeping WLDFR-C011. Program continues to support both risks.
9	DOVHD-C012	Targeted Reliability Program		X		
10	DOVHD-C013	Patrols - Distribution Overhead	X	X		Retired duplicate foundational program code. Only keeping WLDFR-C013. Program continues to support both risks.
11	DOVHD-C014	Pole Replacement		X	X	
12	DOVHD-C015	Overloaded Pole Replacements		X	X	
13	DOVHD-C016	Animal Abatement [2AB,KAC]		X	X	
14	DOVHD-C017	Animal Abatement [2AC,KAD]		X	X	
15	DOVHD-C018	Pole Restoration		X	X	
16	DOVHD-C019	Emergency Distribution Replacements [17B]		X	X	
17	DOVHD-C020	Distribution Replacements [2AA]		X	X	Name change from "Distribution Steady State Proactive Replacements [2AA]"
18	DOVHD-C021	Distribution Maintenance Replacements [KAA]		X	X	Name change from "Distribution Steady State Maintenance Replacements [KAA]"

Table 3-7: 2024 RAMP to 2027 GRC Risk Program Index for Failure of Electric Distribution Overhead Assets / DOVHD

DOVHD Controls						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
19	DOVHD-C022	Distribution Maintenance Replacements [KAQ]		X	X	Name change from "Distribution Steady State Maintenance Replacements [KAQ]"
20	DOVHD-C023	Vegetation Management Data and Technology - Distribution	X	X	X	Name change from "OneVeg Program." Retired duplicate foundational program code. Only keeping WLDFR-C077. Program continues to support both risks.
21	DOVHD-C024	Public Safety Awareness		X	X	
22	DOVHD-C025	Pole Clearing - Routine			X	

Table 3-7: 2024 RAMP to 2027 GRC Risk Program Index for Failure of Electric Distribution Overhead Assets / DOVHD

DOVHD Mitigations						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
1	DOVHD-M002	System Hardening [Overhead]		X	X	
2	DOVHD-M003	Non-Exempt Surge Arrester Replacement		X		Program retired after 2023
3	DOVHD-M004	Expulsion Fuse Replacement		X	X	No CBR provided. Program will retire after 2025.
4	DOVHD-M005	Additional Asset Data Captures	X	X		Retired due to no corresponding POs.
5	DOVHD-M006	Grasshopper and KPF Switch Replacement		X	X	
6	DOVHD-M010	Additional System Automation and Protection - FuseSaver		X		Program retired
7	DOVHD-M011	System Hardening [Remote Grid]		X		Minimal risk reduction
8	DOVHD-M012	3A and 4C Line Recloser Replacement [3A]		X		Program retired
9	DOVHD-M013	3A and 4C Line Recloser Replacement [4C]		X		Program retired
10	DOVHD-M014	Butte County Rebuild		X	X	No CBR provided. Program will retire after 2026. Mitigation is out of scope for 2027 GRC.
11	DOVHD-M022	System Hardening [Underground]		X	X	
12	DOVHD-M023	Backlog Open Tag Reduction - Distribution (Pole Backlog)		X	X	
13	DOVHD-M024	Backlog Open Tag Reduction - Distribution (Capital) [2AA]		X	X	
14	DOVHD-M025	Backlog Open Tag Reduction - Distribution (Expense) [KAA]		X	X	
15	DOVHD-M026	Pole Programs - Replace Tree Attachments		X	X	
16	DOVHD-M027	Vegetation Control/Right of Way Clearing		X	X	Name change from "Pole Clearing"
17	DOVHD-M028	VM Distribution - Targeted Inspection		X	X	Name change from "VM Distribution - Focused Tree Inspections"
18	DOVHD-M029	VM for Operational Mitigations (VMOM)		X	X	Name change from "VM Distribution - Operational Improvements"

Table 3-7: 2024 RAMP to 2027 GRC Risk Program Index for Failure of Electric Distribution Overhead Assets / DOVHD

DOVHD Mitigations						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
19	DOVHD-M030	Vegetation Management - Tree Removal		X	X	
20	DOVHD-M031	Portable Battery		X	X	
21	DOVHD-M032	Permanent Battery		X	X	
22	DOVHD-M033	RSI Battery		X	X	
23	DOVHD-M034	OH Fuses Install/Replace		X	X	
24	DOVHD-M035	Overhead Conductor Replacement		X	X	
25	DOVHD-A001	System Hardening [Underground] (Alternative Workplan)		X		2024 RAMP only
26	DOVHD-A002	Grid Monitoring (Alternative Mitigation)		X		2024 RAMP only
27	DOVHD-M039	Generator and Battery Rebate Program (GBRP)			X	
28	DOVHD-M040	BTM Capital Battery Program			X	
29	DOVHD-M041	Backup Power Transfer Meter program			X	No CBR provided. Benefits are not quantifiable.
30	DOVHD-M043	Reliability Enhancement			X	

Table 3-8: 2024 RAMP to 2027 GRC Risk Program Index for Failure of Electric Distribution Underground Assets / DUNGD

DUNGD Controls						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
1	DUNGD-C001	UG Patrols	X	X	X	
2	DUNGD-C002	Underground Notifications		X	X	
3	DUNGD-C003	UG General Equipment Maintenance and Replacement		X	X	
4	DUNGD-C006	Primary Cable Replacement		X	X	
5	DUNGD-C007	LBOR Switch Replacement		X	X	
6	DUNGD-C008	UG Transformers Temperature Sensor	X	X	X	
7	DUNGD-C010	UG Inspections	X	X	X	
8	DUNGD-C011	Network Cable Replacement		X	X	
9	DUNGD-C012	Network Maintenance and Corrective Work [Transformer Maintenance and Testing]		X	X	
10	DUNGD-C014	Network Component (Transformer, Protector) Replacements - Condition Based [Transformer]		X	X	
11	DUNGD-C015	Network Component (Transformer, Protector) Replacements - Condition Based [Protector]		X	X	
12	DUNGD-C016	Locate and Mark - Distribution		X	X	
13	DUNGD-C017	Public Safety Awareness		X	X	

Table 3-8: 2024 RAMP to 2027 GRC Risk Program Index for Failure of Electric Distribution Underground Assets / DUNGD

DUNGD Mitigations						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
1	DUNGD-M002	Network Venting Manhole Cover Replacements			X	
2	DUNGD-M003	Network Installation of SCADA Equipment for Safety Monitoring	X	X	X	
3	DUNGD-M006	Network Component Replacements - High-Rise Dry-Type Transformers [Transformer]		X		Reclassified with DUNGD-C014
4	DUNGD-M007	Network Component Replacements - High-Rise Dry-Type Transformers [Protector]		X		Reclassified with DUNGD-C015
5	DUNGD-M008	Network Component Replacements - Targeted Network Protector Replacement CMD-Type		X		Reclassified with DUNGD-C014
6	DUNGD-A001	Venting Manhole Cover Replacements (Alternative Workplan)		X		2024 RAMP only
7	DUNGD-A002	Radial Deteriorated Concentric Neutrals (Alternative Workplan)		X		2024 RAMP only

Table 3-9: 2024 RAMP to 2027 GRC Risk Program Index for Public Contact with Intact Energized Electrical Equipment / PCEEE

PCEEE Controls						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
1	PCEEE-C001	Locate and Mark - Distribution		X	X	
2	PCEEE-C002	Public Safety Awareness		X	X	

Table 3-9: 2024 RAMP to 2027 GRC Risk Program Index for Public Contact with Intact Energized Electrical Equipment / PCEEE

PCEEE Mitigations						
Line No.	**Program ID**	**Program Name**	**Foundational**	**2024 RAMP**	**2027 GRC**	**Notes**
1	PCEEE-M001	Additional Signage		X		Funding reprioritized
2	PCEEE-M002	System Hardening [Overhead]		X	X	
3	PCEEE-M003	System Hardening [Underground]		X	X	
4	PCEEE-M005	Substation Distribution - Security Enhancements			X	
5	PCEEE-A001	EPSS non-HFTD		X		2024 RAMP only
6	PCEEE-A002	Proximity Warning Alarms		X		2024 RAMP only
7	PCEEE-A003	System Hardening [Underground] (Alternative Workplan)		X		2024 RAMP only

Table 3-10: 2024 RAMP to 2027 GRC Risk Program Index for Failure of Distribution Substation Assets / DSBSN

DSBSN Controls						
Line No.	**Program ID**	**Program Name**	**Foundational**	**2024 RAMP**	**2027 GRC**	**Notes**
1	DSBSN-C003	Substation Distribution - Patrols and Inspections	X		X	
2	DSBSN-C004	Substation Distribution - Maintenance (Supportive Activities)	X		X	
3	DSBSN-C005	Substation Distribution - Maintenance (Transformer)	X		X	
4	DSBSN-C006	Substation Distribution - Maintenance (Circuit Breaker and Switch)	X		X	
5	DSBSN-C007	Substation Distribution - Maintenance (Other Equipment)	X		X	
6	DSBSN-C008	Substation Distribution - Corrective Maintenance			X	Step 3 Exempt
7	DSBSN-C009	Substation Distribution - Emergency Maintenance			X	
8	DSBSN-C010	Substation Distribution - Replacement (Transformer)			X	
9	DSBSN-C011	Substation Distribution - Replacement (Breaker and Switch)			X	
10	DSBSN-C012	Substation Distribution - Replacement (Other Equipment)			X	Step 3 Exempt
11	DSBSN-C013	Substation Distribution - Emergency Replacement			X	
12	DSBSN-C015	Substation Distribution - Emergency Mobile Transformers			X	Step 3 Exempt
13	DSBSN-C016	Substation Distribution - Line Work Support			X	
14	DSBSN-C017	Substation Distribution - SCADA/RTU Replace			X	

Table 3-10: 2024 RAMP to 2027 GRC Risk Program Index for Failure of Distribution Substation Assets / DSBSN

DSBSN Mitigations						
Line No.	Program ID	Program Name	Foundational	2024 RAMP	2027 GRC	Notes
1	DSBSN-M004	Substation Distribution - Security Enhancements			X	

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 4

WILDFIRE MITIGATION SUMMARY AND STRATEGY SUPPORT

(PG&E-4)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
WILDFIRE MITIGATION SUMMARY AND STRATEGY SUPPORT

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 4
WILDFIRE MITIGATION SUMMARY AND STRATEGY SUPPORT

A. Introduction and Summary

1. Overview

Pacific Gas and Electric Company's (PG&E) wildfire risk mitigation activities are managed by our Wildfire Strategy and Operational Support Organization which aims to reduce the risk of catastrophic wildfires from electric utility infrastructure in PG&E's service territory. The purpose of this chapter is to: (1) provide a summary of PG&E's wildfire risk mitigation programs and activities that have been presented in PG&E's Wildfire Mitigation Plan (WMP) and included in this GRC, including a summary of costs that are included in the Wildfire Mitigation Balancing Account (WMBA) for the related mitigations in the WMP, and (2) describe the activities associated with the Wildfire Strategy and Operational Support Organization to demonstrate that PG&E's expense and capital expenditure forecasts for these activities are reasonable and should be adopted by the California Public Utilities Commission (CPUC or Commission).

2. Summary of Request

PG&E requests that the Commission:

- Adopt the expense forecasts in Section A.2, Table 4-1;
- Adopt the capital expenditure forecasts in Section A.2, Table 4-2; and
- Approve the continuation of the one-way Wildfire Mitigation Balancing Account and the related expenditures.

Requests related to wildfire mitigation costs presented in the WMP and this GRC to be recorded in the WMBA are presented in this chapter, as well as other chapters in Exhibit (PG&E-4) and other Exhibits in this filing, as described in Section B.

Forecasts in this chapter are shown with escalation at the Major Work Category (MWC) and Maintenance Activity Type (MAT) level. Escalation is included in expense and capital totals. For more information on escalation, please refer to Exhibit (PG&E-10), Chapter 15.

TABLE 4-1
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	Workpaper Reference
1	AB	Misc Expense	$19,810	$26,967	$22,143	$28,675	$28,599	$26,817	$27,192	$27,802	WP 4-3, Line 8
2		Total	$19,810	$26,967	$22,143	$28,675	$28,599	$26,817	$27,192	$27,802	

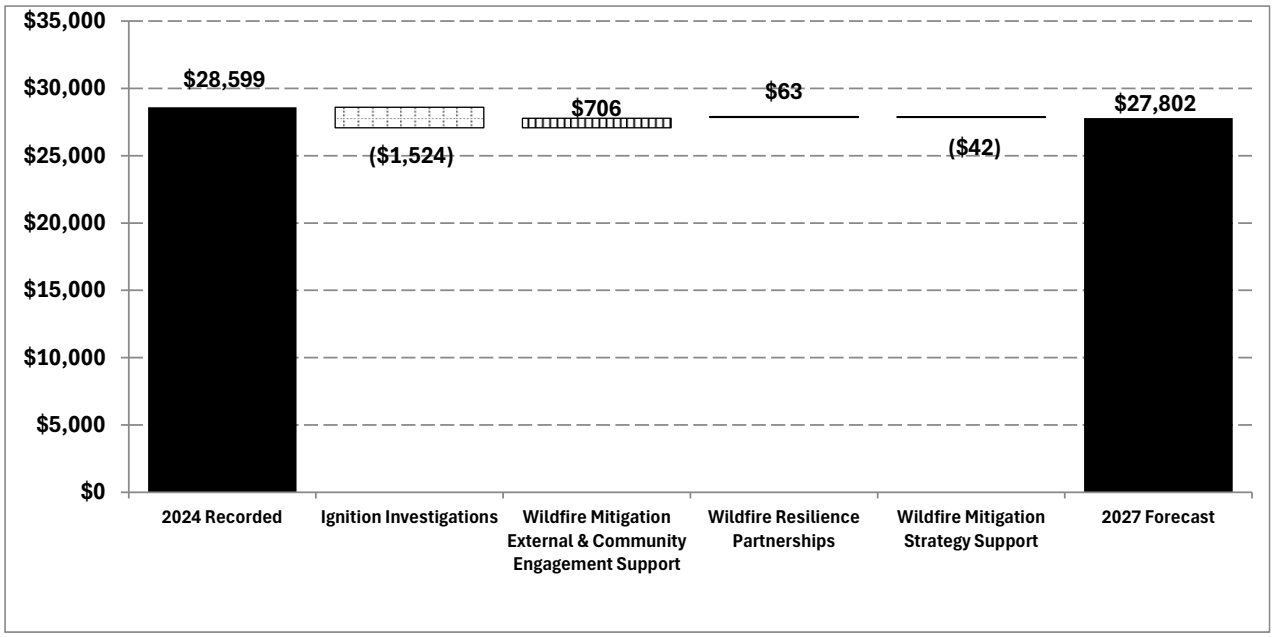
TABLE 4-2
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030	Workpaper Reference
1	21	Misc Capital	$0	$1,894	$7,671	$9,337	$5,978	$6,230	$6,330	$6,393	$6,489	$6,593	$6,705	WP 4-18, Line 4
2		Total	$0	$1,894	$7,671	$9,337	$5,978	$6,230	$6,330	$6,393	$6,489	$6,593	$6,705	

a. Expense

Figure 4-1 provides an expense walk identifying key drivers for the difference in the 2027 forecast as compared to 2024 recorded. Each driver is summarized below.

FIGURE 4-1
EXPENSE WALK 2024-2027
(THOUSANDS OF NOMINAL DOLLARS)

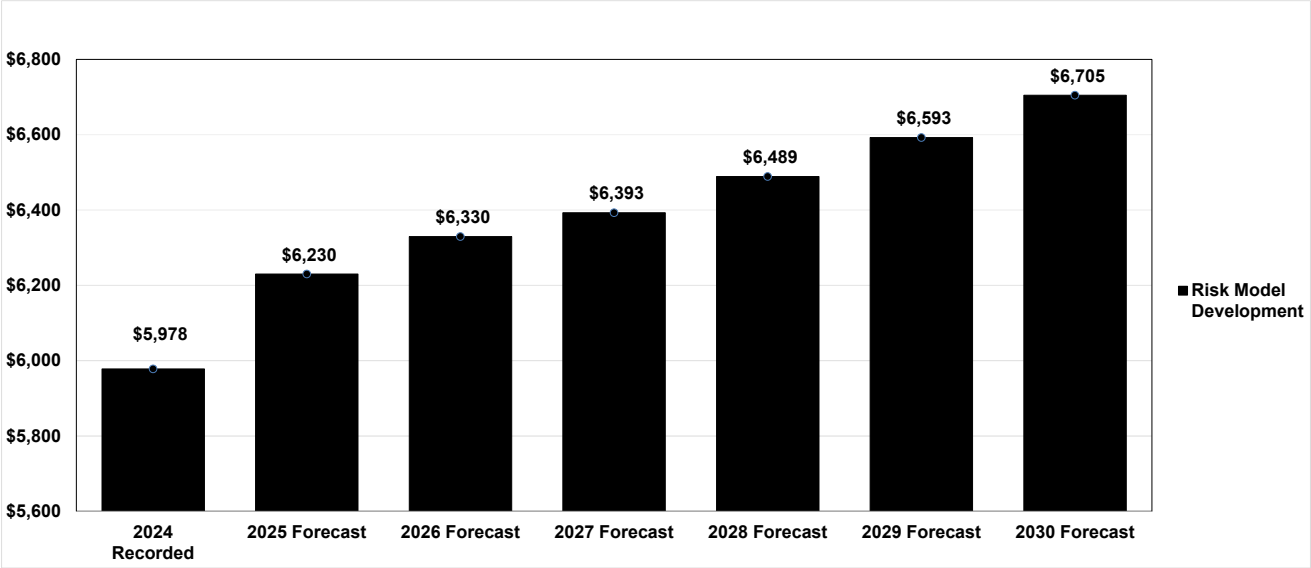


The decrease in the 2027 expense forecast compared to the 2024 recorded adjusted is due to internalizing some of the ignitions investigation work performed by external contractors at a lower cost as the program enters steady state.

b. Capital

Figure 4-2 provides the capital expenditures forecast for Wildfire Mitigation Strategy and Operational Support from 2024 recorded through 2030.

FIGURE 4-2
CAPITAL WALK 2024-2030
(THOUSANDS OF NOMINAL DOLLARS)



The sole capital program in this chapter is the Risk Model Development Program. The 2027 capital forecast increase compared to 2024 recorded adjusted is due to escalation.

3. Risks Addressed

PG&E's forecast for Wildfire Mitigation Strategy and Operational Support addresses the Electric Distribution related risks described in Table 4-3.[1] The Wildfire Mitigation Strategy and Operational Support activities in this chapter are Foundational Activities. Foundational activities, as described in D.21-11-009, are initiatives that support or enable two or more mitigation programs but that do not directly reduce the consequences or reduce the likelihood of risk events. A summary table of the program names and the risk identification for this chapter is presented in Table 4-4.

For each Foundational activity in this chapter, PG&E identifies the risk supported and describes why the activity is necessary and justified in the Program Forecasts Section C below.

[1] For additional information on these risks, see Exhibit (PG&E-4), Ch. 3.

TABLE 4-3
RISKS ADDRESSED BY WILDFIRE MITIGATION STRATEGY AND OPERATIONAL SUPPORT

Line No.	Risk Name	RISK ID	RISK Description
1	Wildfire	WLDFR	The Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands or environment originating from PG&E assets or activities.

TABLE 4-4
FOUNDATIONAL ACTIVITIES, RISK MITIGATIONS AND RISK CONTROL PROGRAMS

Line No.	MAT	Program Name	Risk Program ID(s)	CBR (2027-2030)
Risk Mitigations				
1	AB#	Wildfire Resilience Partnerships – Fuels Treatment	WLDFR-M056	27.5
Foundational Activities				
2	AB#	Wildfire Strategy & Preparation Support	WLDFR-M009	Foundational
3	AB6			
4	21#			

In addition, all programs in this chapter are wildfire mitigations which contribute to climate resilience because they address wildfire risk. For more information, the relationship between this General Rate Case filing and PG&E's climate resilience plans, see Exhibit (PG&E-2), Chapter 1.

B. Wildfire Mitigation Program Overview and GRC Presentation

1. Wildfire Mitigation Program Overview

The California electric utilities submit Wildfire Mitigation Plans (WMP) to establish the utility's approach to mitigating wildfire risk caused by its electric equipment. The Office of Energy Infrastructure Safety (OEIS) prescribes the WMP guidelines[2] and associated compliance requirements for the utilities.

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2 Final WMP Guidelines adopted on February 21, 2025, available at: https://energysafety.ca.gov/what-we-do/electrical-infrastructure-safety/wildfire-mitigation-and-safety/wildfire-mitigation-plans/2026-28-wildfire-mitigation-plan-guidelines/ (accessed April 24, 2025).

In accordance with OEIS guidelines, PG&E submitted its 2026-2028 Wildfire Mitigation Plan on April 4, 2025.[3]

PG&E remains steadfast on our stand that catastrophic wildfires shall stop. Since the filing of the 2023 GRC, PG&E has made substantial progress in constructing, maintaining, and operating our electrical lines and equipment with a safety focus to minimize the risk of catastrophic wildfires. Significant achievements include:

- Installing 1,230 miles of covered conductor since 2018 and undergrounding of approximately 924 circuit miles of distribution powerlines since 2019.[4]
- Advancing our risk modeling capabilities for informing work plans and mitigation initiative selections by developing and adopting the next evolution of the Wildfire Distribution Risk Model (WDRM), version (v) 4 and Wildfire Transmission Risk Model (WTRM), version (v) 3.
- Increasing our situational awareness through 635 high-definition wildfire cameras and gaining a visual coverage of over 90 percent of the Tier 2 and Tier 3 areas of the CPUC's High Fire Threat District (HFTD) map in PG&E's service territory.
- Adapting to changing climate conditions by extending continuous monitoring capabilities through piloting and deploying new technologies like Gridscope devices and Early Fault Detection (EFD), Distribution Fault Anticipation (DFA) and next generation SmartMeter™ devices.
- Adopting Enhanced Powerline Safety Settings (EPSS) throughout our HFTD and High Fire Risk Areas (HFRA) and improving response times to outages; and expanding the program to include Down Conductor Detection (DCD) capabilities.
- Improving reliability, customer, and community impacts by improving scoping techniques and mitigation strategies, and by offering portable

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3 PG&E Wildfire Mitigation Plan 2026-2028, filed April 4, 2025, available at: https://www.pge.com/en/outages-and-safety/safety/community-wildfire-safety-program.html#accordion-99016a73ab-item-4366b98ea7 (accessed April 24, 2025).

4 PG&E Wildfire Mitigation Plan R0 2026-2028 | Volume 1 of 2, Page 6, available at: https://www.pge.com/en/outages-and-safety/safety/community-wildfire-safety-program.html#accordion-99016a73ab-item-4366b98ea7 (accessed April 24, 2025). These values include System Hardening and Community Rebuild work.

and permanent batteries for customers frequently impacted by EPSS and/or Public Safety Power Shutoff (PSPS) outages through a portfolio of direct install and rebate programs such as the Portable Battery Program (PBP) and the Residential Storage Initiative (RSI) Program.

- Improving community outreach and public awareness efforts help to ensure customers and communities are informed and adequately prepared prior to a wildfire or wildfire safety outage.

Even with the progress made so far, there is more work to do. California's climate is experiencing more frequent and severe wind events, periods of extreme precipitation, and intense hot/dry conditions. This hydroclimate "whiplash" significantly amplifies wildfire and reliability risks, increasing the urgency for more targeted and scalable mitigations.

PG&E's 2026-2028 Wildfire Mitigation Plan (WMP) highlights this focus as we strive to stay ahead of the increasing wildfire risk facing California. This plan is built on our existing layers of protection rooted in a solid foundation of mitigations that we have put in place since 2019. The WMP incorporates insights, lessons learned, and emerging best practices from past WMPs, the 2023 and 2024 wildfire seasons, and our wildfire risk analysis in the 2024 Risk Assessment and Mitigation Phase (RAMP) Report. In the 2026-2028 WMP period, PG&E will continue to leverage our foundational framework of risk-informed decision-making to minimize ignition risk and outage impacts. The framework of our wildfire mitigation portfolio includes four categories of mitigations to disrupt the wildfire sequence: (1) comprehensive monitoring and data collection; (2) operational mitigations; (3) system resilience; and (4) community support.[5]

Several actions identified with this WMP framework are highlighted below:

- **Risk-Informed Decision Making:** Our risk-informed decision-making relies on inputs from key wildfire risk models that are continuously improved and expanded. PG&E uses two types of models to address the dynamic wildfire risk across our service territory: (1) operational models for operational mitigations such as PSPS and EPSS that show

[5] See Figure PG&E-1-2 on p. 5 of PG&E's 2026-2028 WMP.

where fire risk is elevated in the short-term, and (2) long-term planning models for resiliency programs that permanently reduce risk by hardening the grid. The 2026-2028 WMP leverages the Wildfire Distribution Risk Model (WDRM) v4; this model is a significant evolution in our approach to quantifying the wildfire risk from overhead distribution assets. Risk model enhancements ensure that our statistical approach to characterizing wildfire risk remains robust and adaptive.

The Wildfire Distribution Risk Model development program is described in Section C.2 in support of this WMP initiative.

- **Comprehensive Monitoring and Data Collection:** The continued evolution of our asset and vegetation management (VM) inspection programs is targeted towards identifying locations that pose the highest risk for an ignition event. These programs evolved based on our learnings over the prior two WMP cycles. The mature capabilities of wildfire cameras, weather stations, and the Hazard Awareness Warning Center will continue to evolve as the underlying technology improves. We are in the initial stages of building real-time monitoring to obtain more dynamic insight into the state of our electric assets in response to accelerating weather volatility. In 2026-2028, we will mature these capabilities as we evaluate and integrate new technology into our grid infrastructure. Early examples of these are EFD, Gridscope devices, and the next generation SmartMeter™ devices.

  Distribution continuous monitoring programs are discussed in Exhibit 4, Chapter 5 in support of this WMP initiative. Next generation SmartMeter™ devices are discussed in Exhibit 6, Chapter 9.

- **Operational Mitigations:** PSPS, EPSS, and DCD are operational mitigations that provide a layer of protection for customers. While these programs are among the most impactful and cost-effective mitigations we deploy, they result in a reliability impact to customers. To address this reliability impact, we undertake initiatives to minimize the scope and duration of outages and support customers before, during, and after wildfire events.

  These WMP operational mitigations are discussed in Exhibit 4, Chapter 6.

- **System Resilience Mitigations:** PG&E's system resilience activities are critical to permanently reducing wildfire risk, minimizing negative aspects of PSPS and EPSS, and strengthening the grid against extreme weather events. Overhead system hardening and undergrounding remain cornerstone initiatives in this effort. As stated in the WMP, PG&E plans to underground approximately 1,077 circuit miles of distribution lines between 2026 and 2028,[6] effectively eliminating ignition risk in those areas and enabling resilience and reliability for other climate hazards such as high heat and more severe winter storms. Similarly, PG&E will complete 718 miles of covered conductor between 2026 and 2028, further enhancing system resilience in high-risk areas.

  PG&E will continue Remote Grid installations, through which PG&E removes overhead power lines and deploys standalone energy systems as an alternative or complement to system hardening. As of 2024 year end, 11 Remote Grids for system hardening are operational, with others in various stages of project development.

  System hardening mitigations for Electric Distribution are discussed in Exhibit 4, Chapter 7.[7]

  Other WMP initiatives such as Backlog Pole Replacements, which mitigates wildfire risks by fixing poles that could lead to outages or ignitions from PG&E's assets is discussed in Exhibit 4, Chapter 15. Service Breakaway Connectors, which is a wildfire risk mitigation program to install service breakaway disconnects in targeted HFTD areas with high risk of vegetation contact, is discussed in Exhibit 4, Chapter 17.
- **Vegetation Management (VM):** PG&E continues to evolve its VM practices, using risk-informed planning to develop and execute on a portfolio of programs. Building upon lessons learned, PG&E plans to streamline its inspection programs while targeting high risk areas of the

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6 PG&E Wildfire Mitigation Plan R0 2026-2028 | Volume 1 of 2, p. 6, available at: https://www.pge.com/en/outages-and-safety/safety/community-wildfire-safety-program.html#accordion-99016a73ab-item-4366b98ea7 (accessed April 24, 2025).

7 PG&E intends to file a 10-Year Electric Undergrounding Plan (EUP) with Energy Safety, and anticipates transitioning undergrounding work to the EUP in 2028. See Ch. 7, Section C.2.b. for further information.

system to continuously reduce ignitions associated with vegetation. In 2026-2028, we will focus on consolidating VM distribution inspection programs, leveraging technology to enhance work execution, and utilizing operational analytics to better scope risk-informed work.

The VM mitigations supporting this WMP initiative are described in Exhibit (PG&E-4), Chapter 8.

- **System Inspections:** For distribution, PG&E introduced the Aerial Scan Inspection to enhance visibility of the highest wildfire-risk locations, supplementing detailed inspections with focused mid-span conductor assessments using drones. We will continue to leverage aerial inspections at scale, building on our 2024-2025 experience. Additionally, targeted infrared inspections will be deployed in areas of emerging concern to proactively address wildfire risk.

  Distribution inspection programs supporting this WMP initiative are described in Exhibit (PG&E-4), Chapter 14.

- **Wildfire Resilience Partnerships:** PG&E has been pursuing various plans to catalyze targeted community and forest fire resilience aligned with locational risk drivers, aiming to mitigate the impacts and consequences of wildfires. These plans consider different forms of resilience partnerships that we are exploring, including facilitating fuels management within utility rights of way along likely wildfire pathways, creating expanded fuel breaks beyond designated rights of way, improving community and forest wildfire defenses, facilitating or co-funding roadside clearing under rights of way along key ingress/egress routes, and collaborative wood management. Since 2023, we have piloted several initiatives with nonprofit organizations and other entities to help drive localized landscape-scale treatment. In 2026-2028, we will continue to form new community partnerships, co-develop projects, and assess the associated benefits.

  The Wildfire Resilience Partnership program is described in Section C.4 and supports this WMP initiative.

2. Key WMP Programs and Related GRC Chapters

PG&E's WMP includes Transmission and Distribution programs with focus in the High Fire Threat Districts (HFTD) and High Fire Risk Areas

(HFRA). The costs for these programs may be recovered through various cost recovery mechanisms, including the General Rate Cases (GRC), Transmission Owner (TO) cases, the Electric Undergrounding Program application pursuant to Senate Bill (SB) 884,[8] or other CPUC applications regarding wildfire mitigations.

In its 2026 WMP, PG&E's initiatives are presented in the eight categories outlined by OEIS guidelines. The mapping of these WMP categories to key Distribution programs and GRC chapters are as shown in Table 4-3 below. The relationship between the WMP and GRC is further discussed in Section D.2.

8 PG&E intends to file a 10-Year Electric Undergrounding Plan (EUP) with Energy Safety, and anticipates transitioning undergrounding work to the EUP in 2028. See Ch. 7, Section C.2.b. for further information.

TABLE 4-5
2026 WILDFIRE MITIGATION PLAN AND 2027 GRC MAPPING

Line No.	WMP Section	WMP Category	Supporting Programs	GRC Chapter[(a)]
1	Section 5	Risk Methodology and Assessment	Risk Model Development, Ignition Investigations	Ch 4 – Wildfire Mitigation Summary and Strategy Support
2	Section 6	Wildfire Mitigation Strategy	Wildfire Strategy Support, Wildfire Mitigation Plan PMO	Ch. 4 – Wildfire Mitigation Summary and Strategy Support
3	Section 7	Public Safety Power Shutoff	PSPS, Circuit Breaker Replacements	Ch. 6 – Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs)
				Exhibit 7, Ch. 9 – Emergency Preparedness and Response
4	Section 8	Grid Design, Operations, and Maintenance	System Hardening	Ch. 7 – Wildfire System Hardening
			EPSS	Ch. 6 – Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs)
			Equipment Maintenance and Repair	Ch. 9 – Electric Distribution Capacity, Engineering and Planning
				Ch. 11 – Electric Emergency Recovery
				Ch. 15 – Overhead Maintenance and Poles
				Ch. 17 – Overhead Infrastructure Replacement and Reliability
				Ch. 18 – Substation Asset Management
				Ch. 22 – Grid Modernization and Grid Technology
			Asset Inspections	Ch. 14 – Distribution Inspections
			Real Estate	Exhibit 7, Ch. 5 – Land, Environmental and Permitting Services
			Emergency Preparedness and Response	Exhibit 7, Ch. 9 – Emergency Preparedness and Response
5	Section 9	Vegetation Management and Inspections	Vegetation Management programs	Ch. 4 – Wildfire Mitigation Summary and Strategy Support Ch. 8 – Vegetation Management Ch. 18 – Substation Asset Management Exhibit 5, Ch. 3 – Hydro Operations Costs

TABLE 4-5
2026 WMP AND 2027 GRC MAPPING
(CONTINUED)

Line No.	WMP Section	WMP Category	Supporting Programs	GRC Chapter[(a)]
6	Section 10	Situational Awareness and Forecasting	Weather Stations, Wildfire Cameras, Real Time monitoring	Ch. 5 – Wildfire Situational Awareness and Forecasting
			SmartMeter devices next generation	Exhibit 6, Ch. 9 – Electric Advanced Metering Infrastructure Program
7	Section 11	Emergency Preparedness, Collaboration, and Community Outreach	Emergency Preparedness & Response	Exhibit 7, Ch. 2 – Transportation and Aviation Services Exhibit 7, Ch. 9 – Emergency Preparedness and Response Exhibit 6, Ch. 7 – Metering Services and Engineering
			Community and External Engagement	Ch. 4 – Wildfire Risk Mitigations Summary and Strategy Support Exhibit 6, Ch. 2 – Local Customer Engagement Exhibit 6, Ch. 4 – Customer Communications
			Community Engagement	Ch. 6 – Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs) Ch. 8 – Vegetation Management
8	Section 12	Enterprise Systems	IT Programs	Ch. 21 – Electric Distribution and Wildfire Mitigation Information Technology

(a) All chapter references refer to Exhibit (PG&E-4), unless otherwise stated.

C. Wildfire Mitigation Strategy and Operational Support Forecast

Wildfire safety is a complex, multifaceted undertaking that demands collaboration among a broad range of internal teams and subject matter experts, including specialists in planning, operations, emergency response, external engagement, and communications. Collectively, these teams develop and execute comprehensive solutions to support customers, communities, and other partners. The Wildfire Mitigation Strategy and Operational Support organization acts as the central authority overseeing both strategic direction and the overall execution on the wildfire risk mitigation activities. This organization's efforts are

organized into six functional categories and discussed below in the general sequence in which the programs are executed.

1. Ignition Investigations and Reporting (Expense MAT AB#)

a. Overview

PG&E employs a comprehensive, forensic-based methodology to investigate ignitions events, systematically gathering data on PG&E-attributable ignitions, analyzing causal factors through field observations and advanced modeling, and developing targeted mitigation strategies based on these findings. This approach provides critical insights that enhance and refine PG&E's wildfire mitigation efforts. The ignition investigation process focuses on:

- Conducting on-site forensic analysis to identify root causes of equipment failures;
- Utilizing PG&E's internal data sources to inform wildfire mitigation priorities;
- Engaging subject matter experts to improve risk identification and assessment;
- Communicating investigation findings to identify gaps in mitigation strategies and inform next steps;
- Leveraging advanced technology for data collection and analytics to assess emerging ignition trends and enhance corrective actions; and
- Benchmarking against industry-leading ignition investigation methodologies to continuously improve investigative practices.

These capabilities are critical to PG&E's overall mitigation strategy as they enable the Company to identify systemic risks, enhance our layers of protection, and continuously revise and update our wildfire mitigation strategy by implementing data-driven actions that reduce the likelihood of future ignitions.

In addition to conducting investigations, there are also rigorous reporting requirements from both the OEIS and CPUC related to

ignitions stemming from OEIS CCR 29300 Notifications,[9] the OEIS Quarterly Data Report, and the Geospatial Data Report.

PG&E's forecast to support the investigations and reporting requirements includes the following activities:

- Analytical and Engineering support, which encompasses consultant forensic engineering and causal evaluation support for PG&E's Enhanced Ignition Analysis (EIA) Program furthering PG&E's understanding about why utility-caused fires occur and informing future wildfire mitigation strategies.
- Ignition intake and reporting, which consists of staff augmentation contractor support for weekend and after-hours ignition intake support. PG&E monitors potential ignition events seven days a week and uses contractor employees to collect data and report on potential events on some weekends.

The Ignition and Reporting Program is a foundational activity for Wildfire risk (WLDFR).[10] As described above, this program reduces wildfire risk by dedicating resources to investigate and identify systemic risks and continuously revise and update our wildfire mitigation strategy based on the data collected.

b. Forecast

Table 4-6 provides the forecast for Ignition Investigations and Reporting.

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9 Cal. Code Regs. tit. 14, § 29300 – Notifications, available at: https://energysafety.ca.gov/wp-content/uploads/regulation-section-29300.pdf, (accessed April 2, 2025).

10 See Table 4-3 for Risk definitions.

TABLE 4-6
IGNITION INVESTIGATIONS AND REPORTING (MAT AB#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	AB#	Ignition Investigations	$0	$5,211	$6,751	$3,783	$3,866	$2,243	$2,284	$2,342

Risk Mitigation and Control Programs

	MAT	Risk Program ID	Risk Program Name	CBR
2	AB#	WLDFR-M009	Wildfire Strategy & Operational Support	Foundational

The forecast for Ignition Investigations and Reporting was developed using the most recent recorded year 2024 costs for relevant activities and then escalating the sum to 2027 dollars, while lowering costs as described below. 2024 recorded data is used as the forecasting method for the 2027 GRC as it is more reflective of the work that will happen in the future compared to averaging prior recorded years.[11]

The 2027 forecast decrease compared to 2024 recorded is because contract-related start-up costs were incurred in 2024 and prior years but not expected to continue in 2025 and beyond. In 2025, the program entered a steady state using internal labor without the contract labor that was needed to start the program. As presented in Workpaper 4-4, the only two activities that are forecasted for Ignition Investigations are for Analytical Engineering and Support, and Ignition intake and reporting. The forecasted spend is consistent with 2024 recorded costs for both activities.

2. Risk Model Development (Capital MWC 21)

a. Overview

PG&E's wildfire risk modeling is a critical function that enables the company to proactively identify, assess and mitigate wildfire threats. By leveraging advanced data analytics and predictive modeling, PG&E continuously enhances its ability to reduce wildfire risk and prioritize mitigation efforts effectively. These efforts involve refining input data, updating modeling assumptions, and improving analytical tools to enhance predictive accuracy. By incorporating recent ignition and outage data, PG&E strengthens its models, ensuring they remain dynamic and responsive to emerging risks.

Key components of PG&E's risk modeling strategy include enhancing data inputs, utilizing advanced modeling tools, collaborating with industry leaders, integrating feedback from regulators, and continuous improvement. PG&E's risk informed decision making relies on inputs from Wildfire Risk models that are continuously improved and

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11 Exhibit (PG&E-4), WP 4-4.

expanded. The 2026-2028 WMP leverages the Wildfire Distribution Risk Model (WDRM) v4; which is a significant evolution in our approach to quantifying the wildfire risk from overhead distribution assets. The risk model enhancements ensure that our statistical approach to characterizing wildfire risk remains robust and adaptive, as these models directly inform PG&E's risk-prioritized mitigation strategies.

PG&E's forecasted costs for the 2027 GRC to support the risk model development pertains to the following activities:

- **Satellite synthetic LiDAR**: Costs to utilize the synthetic LiDAR data derived from Planet Labs satellite data that characterizes the height of trees and their distance from electrical lines. This data is highly predictive in identifying locations with a high likelihood of vegetation related events.
- **Statistical Modeling**: Costs related to advisory analytical consulting and staff augmentation to support the development of machine learning and Artificial Intelligence predictive risk models.
- **Fire Simulation data and tools**: Contract costs to simulate historical fires and potential fires along electrical assets to determine the relative wildfire consequence across PG&E's service territory.
- **Third-party independent Model Validation**: Costs related to independent review of the new risk models and methodologies in the model development process. This validation report is made available to regulators for feedback on areas for improvement to future model improvements.

The Risk Model Development Program is a foundational activity to address Wildfire risk (WLDFR). As discussed above, this program enables PG&E to proactively identify, assess and mitigate wildfire threats through advanced data analytics and predictive modeling. PG&E can, in turn, develop the right strategies to effectively reduce wildfire risk.

b. Forecast

Table 4-7 provides the forecast for Risk Model Development.

TABLE 4-7
RISK MODEL DEVELOPMENT (MWC 21)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	21#	Risk Model Development	–	$1,627	$7,628	$9,336	$5,978	$6,230	$6,330	$6,393	$6,489	$6,593	$6,705
2	21A, 21#	Miscellaneous Support	–	267	43	–	–	–	–	–	–	–	–
3		Total	$0	$1,894	$7,671	$9,336	$5,978	$6,230	$6,330	$6,393	$6,489	$6,593	$6,705

Risk Mitigation and Control Programs

	MAT	Risk Program ID	Risk Program Name	CBR
4	21#	WLDFR-M009	Wildfire Strategy & Preparation Support	Foundational

The forecast for Risk Model Development was developed using recorded 2024 costs for relevant activities and then escalating the sum to 2027 dollars.[12]

The 2027 forecast has a slight increase compared to 2024 recorded due to escalation. As presented in Workpaper 4-19, all four activities that are forecasted for risk model development are consistent with 2024 recorded costs. In the years prior to 2024, there was increased spending associated with initial development of risk models. However, these processes have stabilized, and going forward PG&E's effort will focus on updating, enhancing and incorporating new data sets to create a next generation risk model. 2024 recorded data is the best reflection of the work that will happen in the future and thus used as the forecasting method for the 2027 GRC.

3. Wildfire Mitigation External & Community Engagement Support (Expense MAT AB6)

a. Overview

PG&E conducts extensive external outreach to educate customers, communities and local agencies about wildfire risk, mitigation efforts and PSPS events through open houses, town halls, webinars, and direct outreach. PG&E tailors communication to local needs, leveraging multiple channels such as social media, emails, city council meetings, and an ADA-compliant, multilingual website. These efforts are critical to the success of keeping communities safe and engaged with our wildfire safety efforts.

The External and Community Engagement team provides essential resources to help customers prepare for safety outages and continuously refines outreach strategies based on feedback. In

12 Exhibit (PG&E-4), WP 4-19.

alignment with CPUC requirements[13] and WMP guidelines,[14] PG&E delivers timely information to customers, local agencies, and key stakeholders before, during, and after wildfire season. Outreach efforts include direct-to-customer engagement and community events, as well as coordination with more than 300 cities, counties, and tribal governments to support local emergency planning. PG&E remains committed to improving communication and operations and integrating insights from customers and stakeholders to enhance the effectiveness of the wildfire safety programs.

The Wildfire Mitigation External and Community Engagement Program is a foundational activity for Wildfire risk (WLDFR). The communication and engagement from this program support important mitigations like PSPS and EPSS before, during, and after wildfire season. The insights and feedback gathered from customers and stakeholders are used to enhance the effectiveness of the wildfire safety programs and prioritize work.

b. Forecast

Table 4-8 provides the forecast for External and Community Engagement Support.

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13 CPUC Decisions on De-Energization (PSPS) Guidelines: D.19-05-042 (Phase 1 Guidelines), D.20-05-051(Phase 2 and Additional Guidelines), D.21-06-014 and D.21-06-034 (Phase 3 and Additional Guidelines).

14 Wildfire Mitigation Plan Guidelines Sections 11.3 and 11.4 (February 2025), available at: https://efiling.energysafety.ca.gov/eFiling/Getfile.aspx?fileid=58026&shareable=true (accessed Apr. 17, 2025).

TABLE 4-8
WILDFIRE MITIGATION EXTERNAL & COMMUNITY ENGAGEMENT SUPPORT (MAT AB6)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	AB6	Wildfire Mitigation External & Community Engagement Support	$298	$669	$6,148	$12,486	$12,244	$12,595	$12,708	$12,949

Risk Mitigation and Control Programs

	MAT	Risk Program ID	Risk Program Name	CBR
2	AB6	WLDFR-M009	Wildfire Strategy & Preparation Support	Foundational

The forecast for Wildfire Mitigation External & Community Engagement Support was developed using the recorded 2024 costs and then escalating the sum to 2027 dollars.[15] The forecasted costs for Wildfire Mitigation External & Community Engagement Support consist primarily of third-party consultants' costs for implementing our sustained outreach and engagement plan, and costs associated with internal headcount. PG&E has expanded its efforts on external and community engagement to adhere to regulatory guidelines in recent years, as described above. Because of this, historical costs prior to 2024 are not representative of the costs PG&E is forecasting to incur in future years. Accordingly, the most recent year 2024 is selected as the forecasting method to best represent the needs of this program.

The 2027 forecast increase compared to 2024 recorded is due to escalation.

4. Wildfire Resilience Partnerships (Expense MAT AB#)

a. Overview

PG&E's wildfire resilience efforts are essential to strengthening community-wide wildfire defenses and reducing the consequences of wildfire events. By proactively collaborating with local agencies, non-profits, and other stakeholders, PG&E aims to improve overall community resilience by reducing the potential impact of fast-moving wildland fires. For this reason, the Wildfire Resilience Partnership Program is a mitigation for Wildfire risk (WLDFR).

A key component of these efforts is the development of targeted resilience partnerships that focus on strategic wildfire mitigation measures. These partnerships address managing wildfire fuels within utility rights-of-way along wildfire pathways, creating expanded fuel breaks beyond designed rights-of-way, improving community and forest wildfire defenses, and co-founding or facilitating roadside clearing along ingress/egress routes, etc. By investing in these programs, PG&E helps reduce fire intensity, enhance emergency access, and protect critical

[15] Exhibit (PG&E-4), WP 4-5.

infrastructure. These efforts contribute to broader wildfire mitigation strategies.

PG&E's forecast to support Wildfire Resilience Partnerships includes the following activities:

- Grants to partner organizations which may include Fire Safe Councils, firefighting foundations, Resource Conservation Districts, Tribal governments, and other wildfire resilience nonprofit organizations. These grants can create mutual wildfire risk reduction and other co-benefit value to grantees, communities, and the grantor (PG&E and customers), or to build capacity in such organizations to implement resilience mitigations to reduce likelihood of catastrophic wildfire outcomes and enable more rapid and effective fire response.
- Contracts for supporting wildfire behavioral modeling analytics to inform project selection, design, outcomes, and investment valuation.

The California Wildfire and Forest Resilience task force outlines the key deliverables with highest priority actions in 2025 to increase wildfire resilience across the state. This includes a plan for the Office of Energy Infrastructure Safety (Energy Safety), in coordination with CAL FIRE and the state's public and investor-owned utilities, to develop a strategy to more effectively align utility corridor investments and projects with adjacent landscape and community resilient investments, programs, and projects.[16] PG&E's Wildfire Resilience Partnerships support this task force initiative.

b. Forecast

Table 4-9 provides the forecast for Wildfire Resilience Partnerships.

[16] California Wildfire and Forest Resilience Task Force, 2025 key deliverables, (March 24, 2025), available at: https://wildfiretaskforce.org/wp-content/uploads/2025/03/2025-Task-Force-Key-Deliverables-.pdf (accessed April 24, 2025).

TABLE 4-9
WILDFIRE RESILIENCE PARTNERSHIPS (MAT AB#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	AB#	Wildfire Resilience Partnerships	–	–	–	–	$1,252	$1,260	$1,283	$1,315

Risk Mitigation and Control Programs

	MAT	Risk Program ID	Risk Program Name	CBR
2	AB#	WLDFR-M056	Wildfire Resilience Partnerships – Fuels Treatment	27.5

The forecast for Wildfire Resilience Partnerships was developed using recorded 2024 costs and then escalating the sum to 2027 dollars. This work was initiated in 2024, so there is no historical data prior to 2024 to inform the forecast.[17]

The 2027 forecast has a slight increase compared to 2024 recorded due to escalation.

5. Wildfire Mitigation Strategy Support (Expense MATs AB6, AB#)

a. Overview

PG&E employs a comprehensive wildfire mitigation strategy that integrates operational execution, stakeholder engagement, scientific advancements, and performance monitoring to enhance wildfire resilience and public safety. The Wildfire Strategy Support function is central to this effort, responsible for the overall strategy, operational governance, and execution oversight of mitigation activities. This includes engaging with stakeholders at local, state, and federal levels, collaborating with academic institutions to advance fire science, and exploring innovative technologies and potential solutions. This centralized function provides leadership and oversight across wildfire mitigation activities, ensuring a coordinated approach. Additionally, the organization plays a key role in informing various regulatory filings and evaluating the performance of wildfire mitigation programs.

The Wildfire Strategy Support organization also encompasses the WMP Project Management Office (PMO) group that has an end-to-end responsibility for PG&E's Wildfire Mitigation Plans, from development and submission to Energy Safety to execution and tracking. The PMO provides essential coordination, support, and governance, ensuring effective WMP implementation across all relevant internal teams and workstreams. This includes managing all WMP-related regulatory activities, timely completion and reporting of all commitments, and presenting critical information to various governance forums. The WMP PMO organizes and coordinates benchmarking of wildfire mitigation activities with other utilities in and outside of California.

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17 Exhibit (PG&E-4), WP 4-6.

The forecasted costs for the Wildfire Mitigation Strategy support consists of the following:

- **Wildfire Mitigation Strategy Support Internal Labor**: Costs associated with the internal headcount to support wildfire mitigation work for managing the overall wildfire mitigation strategy and for various categories described in this chapter for Ignition Investigations and Reporting, Risk Model Development, Wildfire Resilience, and WMP PMO.
- **Wildfire Mitigation Strategy and WMP PMO Contracts**: Contract costs for staff augmentation or contractor strategy support.
- **Wildfire Mitigation Effectiveness Assessment**: Contract costs to support the annual study on the effectiveness of PG&E's wildfire mitigation work for wildfire fund durability requirements.

Wildfire Mitigation Strategy Support is a foundational activity to address Wildfire risk (WLDFR). A dedicated team that is responsible for strategy and execution oversight helps ensure wildfire mitigation activities are achieved and continuously responsive to changing risk mitigation needs.

b. Forecast

Table 4-10 provides the forecast for Wildfire Mitigation Strategy Support.

TABLE 4-10
WILDFIRE MITIGATION STRATEGY SUPPORT (MAT AB6, AB#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	AB#, AB6	Wildfire Strategy Support	$16,388	$17,713	$5,506	$10,268	$10,737	$10,720	10,917	$11,195
2	AB#	Wildfire Strategy Contract Support	3,124	1,314	2,948	2,123	500	–	–	–
3		Total	$19,512	$19,027	$8,454	$12,391	$11,236	$10,720	$10,917	$11,195

Risk Mitigation and Control Programs

	MAT	Risk Program ID	Risk Program Name	CBR
4	AB#, AB6	WLDFR-M009	Wildfire Strategy & Operational Support	Foundational

The forecast for Wildfire Mitigation Strategy Support was developed using recorded 2024 costs and then escalating the sum to 2027 dollars.[18] As presented in workpaper 4-7, the major component of this cost is internal labor. PG&E's Wildfire Mitigation Risk Organization has continued to expand since its inception in 2018. During the early stages, the focus of the organization was to lead the regulatory process for WMPs. As discussed in the previous sections, the OEIS and CPUC regulatory and reporting requirements particularly for Ignitions, Community Engagement Support, and the filing of Wildfire Mitigation Plan have expanded since then. The current organization now includes internal staffing to support risk modeling, ignition investigations, external engagement, regulatory filings and managing the overall wildfire strategy for PG&E. Hence the 2024 recorded data which represents the current structure of the organization was used as the forecast basis.

The 2027 forecast has an increase compared to 2024 recorded due to escalation.

D. Compliance

1. Deferred Work Analysis

The 2023 GRC Decision (OP 4) requires PG&E to continue following the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC.[19] The Deferred Work Settlement requires PG&E to include testimony on deferred work if the following criteria are met:

a) The work was requested and authorized based on representations that it was needed to provide safe and reliable service;
b) PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and
c) PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.

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[18] Exhibit (PG&E-4), WP 4-7.

[19] Pursuant to D.23-11-069, p. 900, OP 4, "Pacific Gas and Electric Company shall continue to follow the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC, subject to the limitations of Public Utilities Code Section 8386.3, which restricts the diversion of revenues authorized for certain wildfire mitigation activities."

For work covered in this chapter, PG&E applied these criteria as explained in Analysis of "Deferred Work" discussion set forth in the Electric Distribution Forecast Summary and Investment Planning chapter.[20] This analysis is presented in the workpapers supporting that chapter.[21]

Based on this analysis, no work included in this Chapter was identified as "deferred work" under the terms of the Deferred Work Settlement.

2. 2027 GRC and 2026-2028 WMP Mapping

In the 2022 R.20-07-013 Phase 1 Track 3 Decision, the Commission has included additional Risk Spend Accountability Report, RAMP, and GRC Requirements in Appendix A, which states "The IOUs shall identify capital expenditures and operating costs stemming from an approved WMP as such in the GRC or other applications for cost recovery. Each WMP mitigation shall be mapped to at least one GRC cost category, or to a cost category in a separate WMP cost recovery application if applicable and tracked in the RSAR."[22]

PG&E filed its 2026-2028 Wildfire Mitigation Plan on April 4, 2025.[23] Even though the 2026-2028 WMP has not been approved by the OEIS, for transparency PG&E is providing a preliminary mapping of Electric Distribution-related WMP initiatives to the 2027 GRC. Please see Workpapers 4-21 and 4-23 that include mapping of 2026-2028 WMP initiatives as filed to the 2027 GRC categories.[24]

E. Accounts

1. Retain Accounts without Modifications

a. Wildfire Mitigation Balancing Account (WMBA)

In the 2023 General Rate Case Decision (D.23-11-069), the Commission directed PG&E to modify the Wildfire Mitigation Balancing

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[20] Exhibit (PG&E-4), Ch. 2, Section E.1.b.

[21] Exhibit (PG&E-4), WP 2-19.

[22] D.22-10-022, p. A1.

[23] PG&E 2026-2028 Wildfire Mitigation Plan R0 Vol. 1 & Vol. 2 (April 4, 2025), available at: https://www.pge.com/en/outages-and-safety/safety/community-wildfire-safety-program.html#accordion-99016a73ab-item-4366b98ea7 (accessed April 24, 2025).

[24] Exhibit (PG&E-4), WP 4-21 and 4-23.

Accounts (WMBAs) for the Wildfire related expense and capital from a two-way balancing account to a one-way balancing account.[25] PG&E proposes continuing to use the WMBA to record wildfire mitigation related activities for the 2027-2030 period, including those activities described in this application, as well as any new activities or conclusion of prior activities no longer necessary in PG&E's WMPs[26] to the extent that PG&E does not exceed the total authorized revenue requirement for these balancing accounts. Actual costs above PG&E's total authorized revenue requirement are recorded to the Wildfire Mitigation Plan Memorandum Account (WMPMA) for subsequent reasonableness review and approval by the Commission. Additionally, PG&E proposes to continue returning any overcollection/unspent expense either at the end of the GRC cycle or as an option annually should an overcollection occur and PG&E has determined the funds will not be necessary to fund future work prior to 2031. PG&E summarizes its request to continue existing cost recovery mechanisms as described in this exhibit and associated revenue requirements in Exhibit (PG&E-10), "Results of Operations," Chapter 16 "Balancing Accounts."

PG&E's 2026-2028 WMP implements proactive and reactive measures to address increasing wildfire risk. There are new learnings from each wildfire season on how to further reduce risk to protect our customers and communities. Based on these new learnings, PG&E may adjust its planned mix of wildfire mitigation activities as necessary to address evolving wildfire risks.

California's changing climate is manifested through more frequent and extreme weather events known as "hydroclimate whiplash."[27] This requires PG&E to glean all learnings from wildfires that occur within or outside of California. As such, it may require PG&E to adjust its portfolio

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25 D.23-11-069, p. 878, Conclusion of Law (COL) 176.

26 The WMP for 2029-2031 will occur in the middle of the 2027 GRC cycle and may potentially require additions or removals of certain mitigations.

27 Daniel Swain et al., Hydroclimate Volatility on a Warming Earth (Jan. 9, 2025), available at: https://www.nature.com/articles/s43017-024-00624-z> (accessed April 17, 2025).

of mitigation tools to incorporate new learnings. The WMBA provides an avenue for such expenditures.

The wildfire mitigation forecasts that are presented in this GRC and proposed to be recorded to the WMBA are mitigations with Risk Program IDs that that contain the following attributes: WLDFR-M, WPSPS-M, or WEPSS-M.[28] The primary wildfire mitigation expenses recorded to the WMBA include both operations and maintenance (O&M) and capital wildfire mitigation costs incurred by Electric Distribution. Additionally, other wildfire mitigation costs include O&M expenses and capital expenditures for Shared Services support for wildfire mitigation activities.

Table 4-11 and Table 4-12 summarize the forecast costs for the wildfire mitigations for which PG&E will record in the WMBA. Most of the work included in Table 4-12 is described in Exhibit (PG&E-4) Chapters 4, 5, 6 ,7, 15, 17 and 21 but there is also work in other Exhibit (PG&E-4) chapters. In addition to the wildfire mitigation work in this exhibit, PG&E is forecasting for wildfire mitigation activities in Exhibit (PG&E-6) Customer and Enterprise Solutions and Exhibit (PG&E-7) Shared Services and Information Technology.

28 See Exhibit (PG&E-4), WP 4-24 and 4-25 for a list of all programs proposed to be recorded in the WMBA.

TABLE 4-11
WILDFIRE MITIGATION BALANCING ACCOUNT (WMBA) EXPENSE FORECAST SUMMARY
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Chapter Name	Exhibit	Chapter	Forecast 2027
1	Wildfire Mitigation Summary and Strategy Support	4	4	$27,802
2	Wildfire Situational Awareness and Forecasting	4	5	29,308
3	Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs)	4	6	187,377
4	Wildfire System Hardening	4	7	3,325
5	Substation Asset Management	4	18	4,575
6	Electric Distribution and Wildfire Mitigation Information Technology	4	21	28,959
7	Subtotal Exhibit (PG&E-4)			$281,345
8	Local Customer Engagement	6	2	20,011
9	Customer Communications	6	4	6,293
10	Subtotal Exhibit (PG&E-6)			$26,304
11	Sourcing and Materials	7	3	5,075
12	Real Estate	7	4	1,092
13	Land, Environmental and Permitting Services	7	5	1,250
14	Emergency Preparedness and Response	7	9	57,586
15	Subtotal Exhibit (PG&E-7)			$65,003
16	Total WMBA Expense			$372,653

TABLE 4-12
WILDFIRE MITIGATION BALANCING ACCOUNT (WMBA) CAPITAL FORECAST SUMMARY
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Chapter Name	Exhibit	Chapter	Forecast 2027	2028	2029	2030
1	Wildfire Mitigations Summary and Strategy Support	4	4	$6,393	$6,489	$6,593	$6,705
2	Wildfire Situational Awareness and Forecasting	4	5	12,731	12,935	12,196	11,094
3	Wildfire Operational Mitigations (PSPS, EPSS, and Customer Battery Programs)	4	6	69,679	81,692	77,785	78,459
4	Wildfire System Hardening	4	7	948,944	281,517	222,567	269,978
5	Overhead Maintenance and Poles	4	15	298,841	298,378	299,330	18,739
6	Overhead Infrastructure Replacement and Reliability	4	17	7,500	7,500	–	–
7	Electric Distribution and Wildfire Mitigation Information Technology	4	21	55,437	40,156	72,094	75,594
8	Subtotal Exhibit (PG&E-4)			$1,399,525	$728,667	$690,565	$460,569
9	Metering Services and Engineering	6	7	11,319	16,646	21,440	26,503
10	Subtotal Exhibit (PG&E-6)			11,319	16,646	21,440	26,503
11	Emergency Preparedness and Response	7	9	2,632	2,632	2,632	2,632
12	Subtotal Exhibit (PG&E-7)			$2,632	$2,632	$2,632	$2,632
13	Total WMBA Capital			$1,413,477	$747,946	$714,637	$489,704

(PG&E-4)

F. Conclusion

Based on the demonstration above and on the evidence presented in the associated attachments and workpapers to this chapter, PG&E respectfully requests that the Commission:

1) Adopt the expense forecasts in Section A.2, Table 4-1;
2) Adopt the capital forecasts in Section A.2, Table 4-2; and
3) Approve PG&E's proposal to retain the one-way WMBA as described in Section E.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 5

WILDFIRE SITUATIONAL AWARENESS AND FORECASTING

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
WILDFIRE SITUATIONAL AWARENESS AND FORECASTING

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
WILDFIRE SITUATIONAL AWARENESS AND FORECASTING

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 5
WILDFIRE SITUATIONAL AWARENESS AND FORECASTING

A. Introduction and Summary

1. Overview

This chapter presents Pacific Gas and Electric Company's (PG&E or the Company) expense and capital forecast for its Electric Distribution Situational Awareness and Forecasting activities that are reasonable and should be adopted by the California Public Utilities Commission (CPUC or Commission). Programs described in this chapter represent PG&E's critical Situational Awareness capabilities through grid sensors, wildfire cameras, and weather stations; and advanced forecasting capabilities like high-resolution weather modeling, fuel-moisture forecasts, and dynamic fire spread simulations.

These programs are foundational elements of PG&E's wildfire risk mitigation program. For example, Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS) operations are dependent on outputs from numerous programs in this chapter (Numerical Weather Prediction, Advanced Fire Modeling, Weather Station Project, Meteorology IT Support, and Fire Potential Index (FPI)). These programs directly mitigate the probability of catastrophic fires in the pre-ignition (Line Sensors, Distribution Fault Anticipation, Early Fault Detection, Distribution Sensor Analysis and Support) and post-ignition (Wildfire Cameras) phase of wildfire events.

2. Summary of Request

PG&E requests that the Commission:

- Adopt the expense forecasts in Section A.2, Table 5-1; and
- Adopt the capital expenditure forecasts in Section A.2, Table 5-2.

The expense forecasts in this chapter are shown with escalation at the Major Work Category (MWC) and Maintenance Activity Type (MAT) level for an annual 3 percent escalation rate unless otherwise stated in respective sections. The capital forecasts in this chapter are shown with no escalation.

PG&E will offset the capital escalation through work execution efficiencies to improve affordability.

TABLE 5-1
SUMMARY OF EXPENSE[a]
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	Workpaper Reference
1	AB	Misc Expense	$4	$2	–	–	–	$1,239	$1,104	$985	WP 5-1
2	FZ	E Dist Planning & Ops Engineer	1,470	932	$1,498	$2,699	$2,541	1,869	1,666	5,700	WP 5-1
3	WF[b]	Wildfire Mitigation	14,329	15,335	19,983	23,112	23,366	27,494	26,312	27,724	WP 5-1
4	Total		$15,803	$16,270	$21,480	$25,811	$25,907	$30,602	$29,083	$34,408	

(a) The values reflected in this table may vary from the initial Results of Operations (RO) Model provided with PG&E's GRC filing due to timing differences. The RO Model will be updated to incorporate these errata in a future submission.

(b) Miscellaneous Meteorology in MAT WFM does not appear in the Section B below. Please see Exhibit (PG&E-4), WP 5-3, line 23 for recorded cost information.

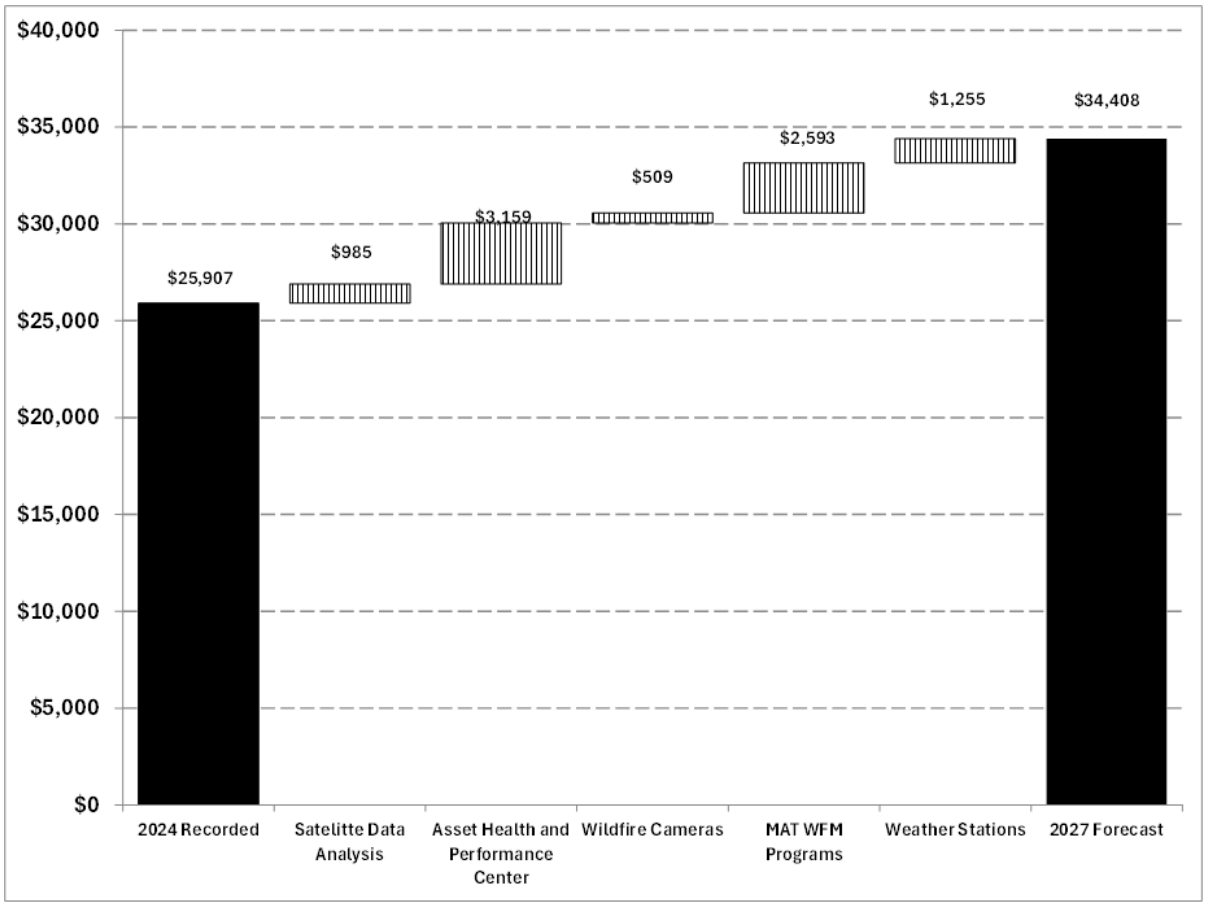
TABLE 5-2
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030	Workpaper Reference
1	3U	Inst/Rpl WildFire Mitgt Eqpmnt	$7,392	$6,575	$12,277	$4,147	$6,686	$11,887	$10,046	$10,036	$10,197	$9,614	$8,745	WP 5-41
2	21	Misc Capital	10,399	13,537	7,703	5,675	4,600	3,193	2,698	2,695	2,739	2,582	2,349	WP 5-41
3	Total		$17,792	$20,111	$19,980	$9,822	$11,286	$15,080	$12,744	$12,731	$12,935	$12,196	$11,094	

a. Expense

Figure 5-1 provides an expense walk identifying key drivers for the difference in the 2027 forecast as compared to 2024 recorded.[1] Each driver is summarized below.

FIGURE 5-1
EXPENSE WALK 2024-2027
(THOUSANDS OF NOMINAL DOLLARS)



The key drivers in the 2027 expense forecast compared to 2024 recorded are as follows:

- Wildfire Cameras (WFC): The increase in the 2027 forecast compared to 2024 recorded is attributable to 70 additional new camera installations, associated maintenance, and data costs.

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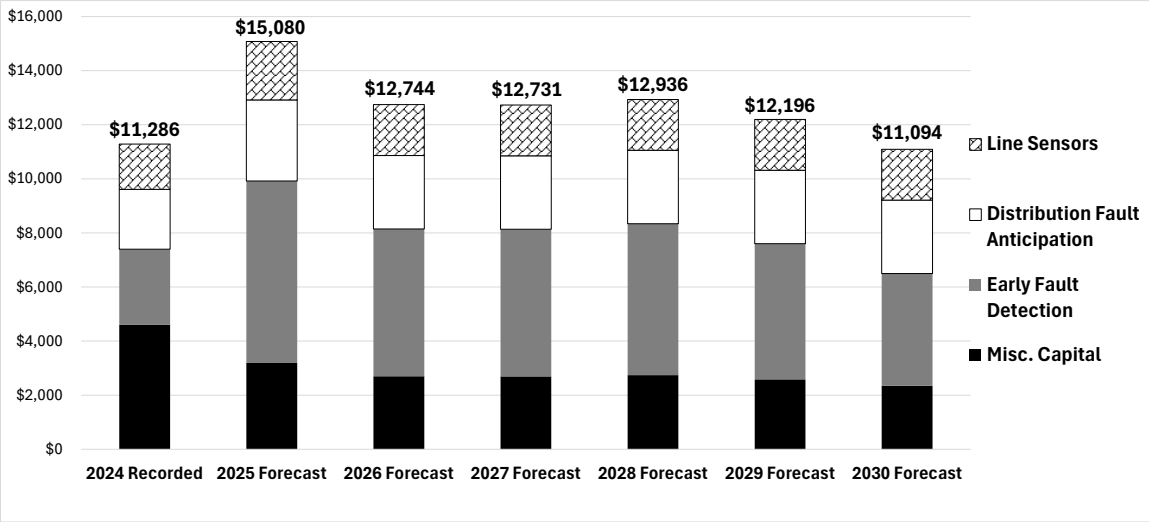
[1] MAT WFM includes the following programs: Advanced Fire Modeling, Fire Potential Index, Meteorology IT Support, Numerical Weather Prediction, Research and Academic Partnership, and Satellite Fire Detection System.

- Weather Stations (WFW): The increase is driven by more weather station units that will need to be maintained and annually calibrated. PG&E also anticipates increased break-fix activities.
- Numerical Weather Prediction (WFM): Anticipated increase in high-resolution weather model data and increased verification and utilization of artificial intelligence enhanced models.
- Asset Health Performance Center (FZA): This program deploys and operates grid sensor technologies; and collects and analyzes sensor data to enable wildfire risk reduction through incipient fault detection and remediation. As more sensors are deployed, expense costs are expected to increase due to (a) increased data analysis and field investigation labor, and (b) technology support and maintenance costs.
- Satellite Data Analysis (AB6): This is a new program that takes advantage of advanced satellite data and technology to bolster situational awareness of vegetation that may present a wildfire risk.

b. Capital

Figure 5-2 provides the capital forecast for Situational Awareness programs from 2024-2030.

FIGURE 5-2
CAPITAL WALK 2024-2030
(THOUSANDS OF NOMINAL DOLLARS)



Note: Misc. Capital includes Meteorology IT Support and Weather Stations

The main programs driving the increase in the 2027 capital forecast are increased deployment of Early Fault Detection Sensors (EFD) (MWC 3UE) and Distribution Fault Anticipation Sensors (DFA) (MWC 3UD) to reduce wildfire risk. Miscellaneous capital (MWC 21) includes expenditures for weather stations and meteorology information technology support. Weather station installation (capital) costs are decreasing as PG&E is installing fewer weather stations annually as the program nears maturity. Meteorology IT Support is decreasing slightly due to anticipated decreased development of weather mapping tools, databases, and systems compared to 2024.

3. Risks Addressed

PG&E's forecast for Wildfire Situational Awareness and Forecasting addresses the Electric Distribution related risks described in Table 5-3.[2] The Wildfire Situational Awareness and Forecasting activities in this chapter are Foundational Activities. Foundational activities, as described in D.21-11-009, are initiatives that support or enable two or more mitigation programs but that do not directly reduce the consequences or reduce the

[2] For additional information on these risks, see Exhibit (PG&E-4), Ch. 3.

likelihood of risk events. A summary table of the program names and the risk identification for this chapter is presented in Table 5-4 below.

For each Foundational activity in this chapter, PG&E identifies the risk supported and describes why the activity is necessary and justified in the Program Forecasts Section C below.

TABLE 5-3
RISKS ADDRESSED BY WILDFIRE SITUATIONAL AWARENESS AND FORECASTING

Line No.	Risk Name	Risk ID	Risk Description
1	Wildfire	WLDFR	The Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands or environment originating from PG&E assets or activities.

TABLE 5-4
FOUNDATIONAL ACTIVITIES, RISK MITIGATIONS AND RISK CONTROL PROGRAMS

Line No.	MAT	Program Name	Risk Program ID(s)	CBR (2027-2030)
Foundational Activities				
1	AB6	Situational Awareness and Forecasting Initiatives - Satellite Data Analysis	WLDFR-M043	Foundational
2	FZA	Situational Awareness and Forecasting Initiatives - Asset Health & Performance Center Expense	WLDFR-M049	
3	WFC	Situational Awareness and Forecasting Initiatives - Cameras	WLDFR-M006	
4	WFM	Situational Awareness and Forecasting Initiatives - Advanced Fire Modeling	WLDFR-M050	
5		Situational Awareness and Forecasting Initiatives - Fire Potential Index O&M	WLDFR-C087	
6		Situational Awareness and Forecasting Initiatives - Meteorology IT support Expense	WLDFR-C089	
7		Situational Awareness and Forecasting Initiatives - Numerical Weather Prediction and Weather Stations	WLDFR-M005	
8		Situational Awareness and Forecasting Initiatives - Research and Academic Partnerships	WLDFR-M051	
9		Situational Awareness and Forecasting Initiatives - Satellite Fire Detection	WLDFR-C086	
10	WFW/WFM	Situational Awareness and Forecasting Initiatives - Weather Station Expense	WLDFR-C088	
11	3UD	Situational Awareness and Forecasting Initiatives - DFA	WLDFR-M045	
12	3UE	Situational Awareness and Forecasting Initiatives - EFD	WLDFR-M044	
13	3UL	Situational Awareness and Forecasting Initiatives - Line Sensors	WLDFR-M046	
14	21A	Situational Awareness and Forecasting Initiatives - Meteorology IT support Capital	WLDFR-M053	
15	21B	Situational Awareness and Forecasting Initiatives - Weather Station Capital	WLDFR-M052	

In addition, all programs in this chapter are wildfire mitigations or controls which contribute to climate resilience because they address wildfire

risk. For more information about the relationship between this General Rate Case filing and PG&E's climate resilience plans, see Exhibit (PG&E-2), Chapter 1.

B. Wildfire Situational Awareness and Forecasting Forecast

1. Satellite Data Analysis (Expense MAT AB6)

a. Overview

Satellite data derived from geostationary and polar orbiting satellites are rapidly advancing and are providing valuable near real-time situational awareness data and historical data for building machine learning or artificial intelligence models. For example, our Outage Probability Weather model deployed in 2024 takes advantage of tree canopy and strike-tree data that can be refreshed every 6 months providing valuable data down to 3-meter resolution. Historical satellite data proved useful to explain the probability of tree-related outages. Additional new features from constellations of private and public satellites are becoming available to bolster situational awareness of fuels, fuel moisture, and the annual grass-crop cycle. For example, we have found the Normalized Difference Vegetation Index, which can measure the general health of plants using red and -near infrared satellite channels, can help us track the seasonality of the grass crop cycle in our High Fire Risk Areas. The Satellite Data Analysis Program is a foundational activity for Wildfire risk. These new and novel satellite data sets are expected to provide a more complete picture of the risk heading into a high-risk weather event such as a PSPS event. This data could lead to better decision making based on a more complete picture of the risk. In addition, we expect our machine learning outage and fire probability models to improve with these robust satellite datasets.

b. Forecast

Table 5-5 below shows the forecast for Satellite Data Analysis.

TABLE 5-5
SATELLITE DATA ANALYSIS (MAT AB6)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	AB6	Satellite Data Analysis	$–	$–	$–	$–	$–	$1,239	$1,104	$985
		Risk Mitigation and Control Programs								
		Risk Program ID	Risk Program Name					CBR		
2		WLDFR-M043	Situational Awareness and Forecasting Initiatives – Satellite Data Analysis					Foundational		

As this is a new program, there were no historical costs utilized to create the forecast. The forecast for 2027 is based on a successful pilot program in 2024 and execution of a vendor (Planet) contract in 2025 ($1,100k/year), plus development of data pipelines, and integration of AI/Machine Learning (ML) models. The 2027 forecast increase as compared to 2024 is driven by the emergence of this project.[3]

2. Asset Health Performance Center (Expense MAT FZA)

a. Overview

The PG&E Asset Health and Performance Center (AHPC) deploys and operates technologies and applications that provide data for real time grid monitoring and analytics of asset health and performance. The AHPC Program is a foundational activity for Wildfire risk (WLDFR) because these technologies and applications predict developing problems on the electric system so PG&E can implement proactive maintenance, reducing wildfire risk and improving public safety. These efforts are achieved by utilizing a portfolio of new and commercially available monitoring and sensing technologies, in combination with advanced analytical and machine learning tools to monitor real-time distribution grid disturbances; identify, locate, and predict developing hazards; and investigate and repair assets prior to failure.

As of 2024, the AHPC manages deployment and operation of Grid Sensor technologies such as Line Sensors, Distribution Fault Anticipation sensors, and Early Fault Detection sensors. Methodologies for fault detection using sensor data for known use cases have been developed in the Foundry Grid Data Analytics & Technology (GDAT) platform. Analysis of alerts (known as Line Risk Evaluations (LREs)), field investigations requested as a result of LREs, field findings, and repair tags (if any) are recorded in GDAT. This enables a closed loop system from detection to wildfire risk mitigation. The AHPC also performs analysis for incipient failure detection in distribution transformers and tracks findings to remediation.

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3 See Exhibit (PG&E-4) WP 5-3, line 3.

Work conducted by the AHPC enables the realization of risk mitigation benefits of grid sensor technologies. In addition to the existing sensors, the Center expects to add to its portfolio fault detection analytics and risk remediation tracking using Gridscope sensors and next generation smart meters in the 2027-2030 GRC period.

AHPC costs include device communication costs, contract costs for software licenses and technical support, and labor costs for (a) monitoring, maintenance, and support of sensor technologies;[4] (b) analytics development; and (c) alert analysis, field investigations, and risk remediation tracking.

b. Forecast

Table 5-6 below shows the forecast for Asset Health and Performance Center.[5]

[4] This includes the Grid Monitoring Systems sensor technologies discussed in sections B.11-B.13 in this chapter (MATs 3UD, 3UE, and 3UL).

[5] The recorded costs in Table 5-6 includes the costs for the support of Grid Monitoring Systems sensor technologies discussed in section B.11-B.13 in this chapter.

TABLE 5-6
ASSET HEALTH AND PERFORMANCE CENTER (MAT FZA)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	FZA	Asset Health & Performance Center	$1,470	$932	$1,498	$2,699	$2,541	$1,869	$1,666	$5,700

Risk Mitigation and Control Programs

	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M049	Situational Awareness – Asset Health & Performance Center Expense	Foundational

The baseline forecast for the Asset Health & Performance Center expense (MAT FZA) was developed using 2024 recorded actuals. Increased costs are anticipated in 2027 compared to 2024 recorded due to the increased volume of sensors that will be deployed by 2027, resulting in additional maintenance, support, analytics, and risk remediation costs.[6]

3. Wildfire Cameras (Expense MAT WFC)

a. Overview

Over the last several years, PG&E has developed and refined its early fire detection capabilities as part of its Wildfire Mitigation Plan. The Wildfire Camera Program consists of 635 high-definition cameras as of the end of 2024, that are sponsored by PG&E and enabled with Artificial Intelligence ignition detection and alerts.

Expenses required to continue this program from 2027 through 2030 will include ongoing operation and maintenance costs of the wildfire cameras as well as the camera system's Artificial Intelligence detection and alerting capabilities.

Since 2018, PG&E has contracted with the ALERTCalifornia[7] consortium, the University of California San Diego, and Digital Path to help manage the wildfire cameras and system. The vendors provide, install, and maintain the cameras (including hardware and software) and maintain a fully redundant data center.

Wildfire cameras improve overall situational awareness from ignition to fire containment and are a valuable tool for assisting the Hazard Awareness and Warning Center, first responders, and fire agencies. By implementing this wildfire camera system, PG&E has achieved visual coverage of over 90 percent of the Tier 2 (elevated risk) and Tier 3 (extreme risk) areas of the California Public Utilities Commission's High Fire Threat District (HFTD) map in PG&E's service territory.

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6 See Exhibit (PG&E-4), WP 5-3, lines 7-13.

7 UC San Diego, ALERTCalifornia, available at: https://alertcalifornia.org/ (accessed April 29, 2025).

The Wildfire Camera Program is a foundational activity for Wildfire risk (WLDFR). While the wildfire camera system does not directly reduce wildfire ignition risk, the risk is reduced because PG&E gains valuable visual intelligence and potential early warning of wildfires that could impact customers, communities, as well as PG&E's assets and facilities. The camera system will continue to provide agency partners and PG&E with additional information to take response actions. In addition, PG&E will provide employees with real time situational awareness to initiate personal safety actions and response.

b. Forecast

Table 5-7 below shows the forecast for Wildfire Cameras.

TABLE 5-7
WILDFIRE CAMERAS (MAT WFC)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	WFC	Wildfire Cameras	$6,956	$8,051	$11,878	$12,340	$11,018	$12,715	$11,386	$11,527

	Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M006	Situational Awareness and Forecasting Initiatives - Cameras	Foundational

The forecast reflects an overall reduction in contract costs based on savings reached through negotiations with the contract partner. Additionally, the forecast for the Wildfire Camera Program was developed using annual pricing that has been specified in our contracts with our vendors, University of California San Diego and Digital Path, through the end of 2027.

The 2027 forecast increase as compared to 2024 recorded is primarily driven by additional costs associated with having a higher total number of cameras sponsored by PG&E than previously in 2024 (705 wildfire cameras versus 635) and escalation.[8]

4. Advanced Fire Modeling (Expense MAT WFM, Capital MAT 21A)

a. Overview

The Advanced Fire Modeling (AFM) project is a foundational activity to the Wildfire (WLDFR) risk. AFM provides core data and analysis to support the EPSS and PSPS programs and daily mitigation activities that reduce the risk of utility-caused ignitions. The main goals of the program are to improve, deploy, and maintain operational models that help PG&E predict the consequence and risk of fires. This project supports the following four main areas:

1) Forecast and Historical Fire Spread Modeling

PG&E has incorporated cutting-edge fire spread simulation data in an operational and planning capacity to estimate the impact and potential consequences of ignitions. Some ignitions may have minimal impact on the surrounding area and communities, while other ignitions could result in significant loss of life and property damage.

Through benchmarking with leading utilities in the wildfire risk mitigation space, we identified Technosylva as a leading vendor who could deliver the operational and historical fire spread simulations required to support operations. These tools are used by many utilities such as PG&E, SCE, SDG&E, PacificCorp, Xcel,

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8 See Exhibit (PG&E-4) WP 5-5, WP 5-6.

Liberty as well as the United States Forest Service (USFS) and CAL FIRE.

In 2021, Technosylva fire simulations were introduced as a tool to help inform PSPS decisions through the Catastrophic Fire Behavior evaluation of the PSPS decision making framework. Technosylva fire simulation outputs are used to assess areas that may have a low probability of ignition but with potential fire behavior resulting in high consequences.

Twice per day, PG&E delivers high resolution weather and fuels moisture data to Technosylva, who then performs over 100 million fire spread simulations every three hours out ~5 days. Simulations are performed every 100 meters across all overhead distribution and transmission lines inside and near PG&E's High Fire Risk Areas. Simulations provide fire spread outputs (e.g., potential number of acres burned, population impacted, buildings impacted, estimated number of buildings destroyed, flame length, and rate of spread) and can be visualized per overhead circuit or for each simulation point in forecast mode to determine the highest risk circuits every three hours.

Importantly, Technosylva also simulates fires through a climatology of weather, fuel moistures, and fuel model datasets. To test and calibrate fire spread output metrics for PSPS, PG&E created one of the largest known climatologies of fire spread simulations. Matching our forecast application, a fire simulation was initiated every 100m along overhead assets for every day of the year between 2017 – 2022 totaling 2,191 days. Further simulations were also initiated on 355 of the worst fire danger weather dates between 2002 and 2016 to help define the tail risk of the distribution of fire simulation results. The worst fire weather dates include Diablo wind events, PSPS events, catastrophic fire occurrence days, and typical hot and dry summer days. For each date, PG&E provided historical hourly weather, and dead and live fuel moisture from the 30+ year climatology, so that each fire spread simulation can take advantage of dynamic hour-by-hour data to simulate

spread hour-by-hour. Over 2.4 billion fires were simulated across 2,546 dates for the climatology analysis and simulation data was key to calibrating our fire spread PSPS guidance for operational decision making. The funding requested in AFM will support the following fire spread model activities:

- Daily fire spread simulations conducted 2x per day;
- Surface and canopy fuel mapping and model enhancements required to run the model;
- Historical fire spread simulations for PSPS damage and hazard evaluation, and climatological analyses;
- Fire simulation data ingestion and processing for PSPS applications;
- Fire Behavior Analyst Consulting support; and
- Fire modeling validation/calibration and reporting.

2) Fire Potential Index Enhancements

The Fire Potential Index (FPI) is an internally-developed model to understand the potential for large and catastrophic fires to occur across the PG&E territory. FPI informs operational decision making of Public Safety Power Shutoff (PSPS), Enhanced Powerline Safety Settings (EPSS), and informs crews what precautions must be taken to reduce the risk of fires as directed by utility standards. FPI is also a key input into the consequence formulation of PG&E's planning models[9] that inform key long term wildfire risk programs of undergrounding and system hardening prioritization. Improvements in FPI model accuracy allow for greater operational mitigation of utility caused wildfire risk through PSPS and EPSS for a given customer impact, and better strategic prioritization of undergrounding and other wildfire risk mitigation programs.

The FPI model has been enhanced several times over the past 10 years, with the latest model (FPI v5.0) being developed in 2022 and 2023 and approved for operations starting August 2024. FPI

[9] These models include the Wildfire Distribution Risk Model and Wildfire Transmission Risk Models.

v5.0 has several enhancements over the previous version that include:

- Addition of fire radiative power for FPI classes to better identify catastrophic fires;
- Expanded model training data;
- Improved spatial relations of weather, fuel moisture, fuels, and terrain data;
- Finer spatial resolution of 0.7km^2 hexagons to capture greater detail of terrain and fuel categories compared to the previous 2x2km (4km^2) grid cell aggregation of fuels and terrain;
- Improved temporal resolution and coupling of satellite-detected fire growth and temporal relations to weather and fuel moisture features; and,
- New weather and fuel moisture input features including soil moisture, enhanced dead and live fuel moisture models, new herbaceous fuel moisture model, solar radiation, and new fuel properties features added including fuel bed depth and fuel complexity.

The operational application of FPI is forecast twice per day with hourly fire growth probabilities down to each 0.7km^2 hexagon with a forecast horizon of 129 hours with fuel moisture and weather inputs from the ensemble of PG&E's Operational Mesoscale Modelling System (POMMS). The same model configuration used to construct the climatology of weather and fuel moistures is utilized in the forecast model application. Strategic applications of FPI are based on PG&E's 30+ year down-scaled weather and fuel moisture climatology, fuel types, and terrain down to 0.7km^2 resolution.

Funding is requested to continue to update the model with the latest weather, fuels, and fire occurrence data and importantly to evaluate new methods, including novel Machine Learning and Artificial Intelligence, to improve the FPI model.

3) Dead and Live Fuel Moisture Modeling and Sampling

The moisture content in living and dead vegetation is a critical input to PG&E's FPI and the National Fire Danger Rating System

used by state and federal fire agencies. PG&E remains committed to continued model operations and advancements in this space.

In 2020, PG&E partnered with Atmospheric Data Solutions (later acquired by Technosylva) to develop the next generation of Live Fuel Moisture (LFM) and Dead Fuel Moisture (DFM) models deployed at PG&E. The models use our high-resolution weather data as inputs to generate hourly dead and live moisture outputs at 2x2 km resolution, each hour, out ~5 days.

The DFM model outputs the moisture content in the 1-, 10-, 100-, and 1000-hour DFM classes, while the LFM model outputs data for specific plant species such as Chamise and Manzanita. In addition, 30+ year climatologies of DFM and LFM are constructed and updated yearly to maintain the robust dataset to re-train models like FPI against fuel dryness levels and historical fires. This work also supports project management activities of the LFM sampling project. Samples are collected from at least 25 locations bi-weekly to monthly by PG&E crews and processed in-house. Results are shared with the public through national databases and used for situational awareness of LFM levels and are importantly used to validate and train future LFM models.

From 2027 to 2030, PG&E plans to continue to operate the DFM and LFM models operationally as they are foundational to PG&E's FPI, Fire Spread Modeling, and PSPS programs. We also plan to continue the LFM sampling program. Each year, PG&E plans to add to its existing fuels climatology such that additional studies to recalibrate and improve FPI predictions are possible.

4) Advanced Fire Occurrence Dataset and Data Acquisition

The PG&E FPI is trained on a novel fire occurrence dataset developed and published by Sonoma Technology[10] that combines agency fire information with satellite fire detections. Fire detections

[10] McClure *et. al., Consistent, high-accuracy mapping of daily and sub-daily wildfire growth with satellite observations*, (2023), available at: <https://doi.org/10.1071/WF22048> (accessed April 24, 2025).

are derived from satellite infrared data and provide information on the location, intensity, and time of fires. We plan to continue working with vendors to improve fire occurrence datasets to allow for improved calibration of models. We strive to help build hour by hour fire spread perimeters and intensity metrics for every incident so we can correlate fire growth and spread to high-resolution, hourly datasets of weather and fuel moistures, high resolution topography and fuel loading to improve models such as the FPI. Funding is requested to continue to pursue improvements to core datasets like fire occurrence, which should improve as additional satellites and improved remote sensing technologies become available.

Advanced Fire Modeling also requires PG&E to acquire weather station data for PSPS and real-time decision-making purposes. Data from over 1500 weather stations (and growing) must be collected through satellite or cellular modems every 10 minutes (or every 30 seconds when on-demand data is requested). This equates to over 230,000 station observations recorded and ingested per day and over 80 million records annually from the PG&E weather station network. All station data is made available to the public via Synoptic[11] and the National Weather Service (NWS) weather and hazards data viewer.

b. Forecast

Tables 5-8 and 5-9 below show the forecast for Advanced Fire Modeling.

[11] Synoptic Data Viewer, available at: <https://explore.synopticdata.com/metadata/map/3765,-11768,6?network=229> (accessed April 24, 2025).

TABLE 5-8
ADVANCED FIRE MODELING (MAT WFM)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	WFM	Advanced Fire Modeling	$5,712	5,718	$5,517	$6,045	$6,997	$6,868	$7,075	$7,287

	Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M050	Situational Awareness – Advanced Fire Modeling	Foundational

TABLE 5-9
ADVANCED FIRE MODELING (MAT 21A)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	MAT Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	21A	Advanced Fire Modeling	$899	$14	$4	$-	$-	$-	$-	$-	$-	$-	$-

The forecast for Advanced Fire Modeling was developed using 2024 recorded program costs escalated to 2027 costs. The 2027 forecast increase as compared to 2024 recorded is driven by escalation.[12]

5. Fire Potential Index (Expense MAT WFM)

a. Overview

This program supports the operations and maintenance of the Fire Potential Index (FPI) website and forecast dissemination system. The system has been operational for over a decade and requires ongoing maintenance.

The Fire Potential Index Program is a foundational activity for Wildfire risk. The FPI is a critical tool for wildfire risk mitigation and directs what mitigations must be considered to reduce the risk of fire ignitions daily. This request includes FPI output quality control reviews by subject matter experts, FPI data dissemination via web application, API and distribution list service and a front-end webpage.

b. Forecast

Table 5-10 below shows the forecast for Fire Potential Index.

12 See Exhibit (PG&E-4), WP 5-3, line 21, WP 5-45 line 2.

TABLE 5-10
FIRE POTENTIAL INDEX (MAT WFM)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	WFM	Fire Potential Index	$93	$134	$132	$141	$110	$162	$145	$203

Risk Mitigation and Control Programs

	Risk Program ID	Risk Program Name	CBR
2	WLDFR-C087	Situational Awareness and Forecasting Initiatives - Fire Potential Index O&M	Foundational

The forecast for Fire Potential Index was developed using a base forecast derived from a three-year historical average (2022-2024) and then escalated to 2027 dollars as described in Section A.2. This base forecast was then combined with incremental support activities anticipated in 2027 versus 2024 as the FPI forecast system continues to evolve in complexity.[13]

6. Meteorology IT Support (Expense MAT WFM; Capital MAT 21A)

a. Overview

Each day, PG&E's Meteorology team processes several terabytes of weather, fuels, fire simulation, and model data. To process these vast quantities of weather model data, as well as to run internal models such as the FPI and Outage Probability Weather (OPW) model, a robust computing infrastructure and IT support structure is required. Meteorology IT Support expense costs entail labor activities such as ongoing maintenance, disaster recovery exercises, planning, and data migration/conversion for the models, tools, data and applications discussed in this chapter.[14]

Meteorology IT Support capital costs entail the continued development of PG&E's flagship meteorology situational awareness platform, WeatherMap, as well as any new or emerging IT development required to support programs, data feeds and Application Programing Interfaces (APIs) in this chapter that can be developed in-house. WeatherMap presents live weather station data, assets, lightning, radar, precipitation amounts, machine learning forecasts and much more in a web interface hosted in AWS. New or emerging projects may include creation or development of data pipelines, databases, APIs, and data visualizations to support integration into core models and decision support systems for risk mitigation purposes.

The Meteorology IT Support Program is a foundational activity for Wildfire risk. The program ensures that compute and data systems,

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13 See Exhibit (PG&E-4), WP 5-3, line 22.

14 Cloud data storage and compute costs are covered in Exhibit (PG&E-7) Ch. 7 of this GRC.

which support internal models and programs related to wildfire risk mitigation, are operating in a reliable state.

b. Forecast

Tables 5-11 and 5-12 below show the forecast for Meteorology IT Support.

TABLE 5-11
METEOROLOGY IT SUPPORT (MAT WFM)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	WFM	Meteorology IT Support	–	$180	$4	$470	$293	$450	$464	$477

	Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-C089	Situational Awareness and Forecasting Initiatives – Meteorology IT Support Expense	Foundational

TABLE 5-12
METEOROLOGY IT SUPPORT (MAT 21A)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	MAT Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	21A	Meteorology IT Support	-	$975	$729	$904	$2,609	$1,767	$1,493	$1,491	$1,515	$1,429	$1,300

	Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M053	Situational Awareness and Forecasting Initiatives – Meteorology IT Support Capital	Foundational

The expense forecast was developed using an average of historical costs from 2023-2024 and escalating to 2027.[15] The 2027 forecast is equivalent to 2023 recorded costs, and higher than the 2024 recorded costs. This increase is primarily driven by escalation over the 2023-2024 average, and anticipated increase in labor costs to maintain meteorology's compute and data system.

The capital forecast was developed using an average of historical recorded costs from 2023-2024 and anticipated development effort of meteorology data systems in the cloud in 2027, which is expected to be lower than 2024.[16] Thus, the 2027 forecast decrease compared to 2024 is driven by a decreased level of development of meteorology's systems. 2024 also represents a high-water mark year due to significant development on the PSPS execution dashboard that integrates with the dynamic PG&E WeatherMap.

7. Numerical Weather Prediction (Expense MAT WFM)

a. Overview

Every PSPS decision (when and where to deenergize) and each EPSS decision (which lines to enable/disable) depend on accurate weather forecasts (e.g., temperature, wind speed, humidity). We remain committed to utilizing the best-available forecast methods and models and advancing our numerical weather prediction capabilities to enhance critical decision support systems. The Numerical Weather Prediction Program is a foundational activity for Wildfire risk. These systems help mitigate catastrophic wildfires through PSPS, enable targeted PSPS decisions, and ensure PG&E is prepared to manage upcoming weather events (winter storms, heat events, wind events, snow, thunderstorms, etc.).

Numerical Weather Prediction costs support:

1) Continued operations and improvements to PG&E's mesoscale modeling system (POMMS). The current operational model configuration consists of two deterministic models initialized by

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15 See Exhibit (PG&E-4), WP 5-3, line 24.

16 See Exhibit (PG&E-4), WP 5-45, line 3.

different global weather models as well as a nine-member ensemble to gauge forecast uncertainty. The models are run on a 2x2 km cartesian grid with each model run extending out 129 hours from initialization time, which generates over 10 billion data points of weather at the surface daily. During high-risk periods, high-resolution simulations at 0.67x0.67 km can be conducted on demand. Although higher resolution models can produce more localized results, we aim to balance model costs with model performance and novel approaches. Model resolution versus computing cost sensitivity studies were conducted and we found running on a 1x1 km model resolution was 6.2 times more expensive than our current resolution of 2x2 km. This study only considered compute costs to run the model, and did not consider the significant additional costs of storage and downstream computing to produce sub-models. PG&E is exploring more cost-effective approaches, such as intelligent sub-selection of outputs from a global model ensemble to better handle uncertainty, or machine learning and artificial intelligence, to downscale 2x2 km outputs to a finer resolution considering topography among other factors.

2) Creation and extension of the POMMS climatology dataset. The climatology is a 30+ year backcast using the same weather model configuration, resolution (2x2 km), and time-stepping as the operational model. This data set provides surface variables every hour, going back at least 30 years. Additional data is appended to the dataset yearly. This dataset contains over 4.5 trillion datapoints of wind, temperature, relative humidity, soil moisture, solar radiation, etc., that are used to help build and train machine learning models such as FPI and Outage Probability Weather (OPW), calibrate

PSPS guidance, and produce PSPS backcasts, among many use cases.[17]

3) Operations and enhancements to the Storm Outage Prediction Project (SOPP) through advancements of a novel machine learning Outage Probability Weather (OPW) model. The goal of OPW is to accurately predict the probability of unplanned outages each hour for each model grid cell through the forecast horizon (currently 129 hours). OPW is a core component of each PSPS decision as OPW is a factor of the Catastrophic Fire Probability Distribution model. The Numerical Weather Prediction program team is responsible for developing, maintaining, and issuing the SOPP model which is used by various teams at PG&E, like the Emergency Recovery team.

b. Forecast

Table 5-13 below shows the forecast for Numerical Weather Prediction.

[17] More information of the V4.0 operational configuration methodology is discussed in Capenter, et. al., *Improving a WRF-Based High-Impact Weather Forecast System for a Northern California Power Utility*, Atmosphere 2024 (August 29, 2024), available at: <https://www.mdpi.com/2073-4433/15/10/1244>, (accessed April 3, 2025).

TABLE 5-13
NUMERICAL WEATHER PREDICTION (MAT WFM)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	WFM	Numerical Weather Prediction	$1,627	$1,797	$1,917	$1,881	$1,997	$2,812	$2,507	$3,259

Risk Mitigation and Control Programs

	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M005	Situational Awareness and Forecasting Initiatives– Numerical Weather Prediction and Weather Stations	Foundational

The forecast for Numerical Weather Prediction was developed using 2024 recorded costs plus forecast incremental spend on executed contracts and anticipated internal labor costs in 2025, with an expected increase in costs in 2027 due to enhancement of the program.[18]

The 2027 forecast increase as compared to 2024 recorded is primarily driven by increased vendor costs to execute and run our high-resolution weather model, and expected enhancements to model resolution, increases in ensemble output, and enhancements to outputs with machine learning or artificial intelligence applications to improve forecast outputs. We anticipate rapid deployment of new AI-enhanced weather models to continue through 2027[19] in both the private and public sector leading to an increased need and demand to build, test, and operationalize new and higher resolution weather models.

8. Research and Academic Partnerships (Expense MAT WFM)

a. Overview

This project supports research efforts and partnerships with leading academic institutions in fire weather, fire science, numerical weather prediction, and outage modeling. We are engaged with two leading research institutions as of 2025, which are the Wildfire Interdisciplinary Research Center (WIRC)[20] and The Center for Weather Innovation and Smart Energy and Resilience (WISER).[21] These institutions are Industry–University Cooperative Research Centers (IUCRCs),[22] which

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18 See Exhibit (PG&E-4), WP 5-3, line 20.

19 See Radford, J., Ebert-Uphoff, I., Stewart, J., Musgrave, K., DeMaria, R., Tourville, N. and Hilburn, K. (2025). *Accelerating Community-Wide Evaluation of AI Models for Global Weather Prediction by Facilitating Access to Model Output*. Bulletin of the American Meteorological Society 106(1) pp. E68-E76. Available at: <https://journals.ametsoc.org/view/journals/bams/106/1/BAMS-D-24-0057.1.xml> (accessed April 3, 2025).

20 Wildfire Interdisciplinary Research Center, available at: <https://www.wildfirecenter.org/> (accessed April 3, 2025).

21 The Center for Weather Innovation, Smart Energy & Resilience (WISER) Industry-University Cooperative Research Center (IUCRC), available at: <https://wiser-iucrc.com/> (accessed April 3, 2025).

22 The Industry-University Cooperative Research Centers (IUCRC), available at: <https://iucrc.nsf.gov/about/> (accessed April 3, 2025).

is a National Science Foundation program that accelerates research through partnerships between industry and world-class academic teams. IUCRCs are designed to perform research-to-operations projects and are funded by members of an industry advisory board.

Funding supports membership to both the WIRC and WISER research centers as well as PG&E-specific projects with researchers, professors, and graduate students.

The Research and Academic Partnership Program is a foundational activity for Wildfire risk.

b. Forecast

Table 5-14 below shows the forecast for Research and Academic Partnerships.

TABLE 5-14
RESEARCH AND ACADEMIC PARTNERSHIPS (MAT WFM)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	WFM	Research & Academic Partnerships	–	–	–	–	$1	$485	$500	$550

	Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M051	Situational Awareness and Forecasting Initiatives – Research and Academic Partnerships	Foundational

The base forecast for Research and Academic Partnerships was developed using executed contract costs in 2025 and escalating (see Section A.2) to 2027 dollars.[23] By 2027 we also anticipated increased research needs to evaluate and operationalize models enhanced with artificial intelligence or machine learning. The historical costs of the program through 2024 were embedded in the meteorology PCC cost center (Misc Meteorology) but will be broken out in 2025 and beyond for transparency.

9. Satellite Fire Detection System (Expense MAT WFM)

a. Overview

This project involves continued operation of a fully operational satellite-based fire detection and alert system using an array of Geostationary and Polar orbiting satellites. The Satellite Fire Detection System is a foundational activity for Wildfire risk. Satellite fire detection provides PG&E with valuable, timely information about new fires and the spread and intensity of existing fires. This information can be used to ensure the safety of customers and utility workers in the area, help identify assets at risk and provide situational awareness as to the burn severity and rate of spread.

As of 2024, the system ingested and reconciled fire detection data from two Geosynchronous Satellites and four polar orbiting satellites. PG&E developed the system to incorporate new fire detection data feeds as they become available and plans to incorporate any new satellite feeds from 2027 to 2030 as more satellites are deployed by National Oceanic and Atmospheric Administration (NOAA) and National Aeronautics and Space Administration (NASA). PG&E will continue to work with industry leading fire detection algorithm developers and experts to procure feeds of satellite fire detection data with the lowest latency available.

To visualize and interact with the fire detection data, we incorporated the system into the WeatherMap, which contains overlays of many different assets and layers as described in the Meteorology IT

23 See Exhibit (PG&E-4) WP 5-3, line 19.

Support forecast overview (Section B.4.a). We plan to keep the system operational through 2030 and incorporate new public satellite data when available. This system is a key situational awareness tool to become aware of and keep track of emerging wildfires.

b. Forecast

Table 5-15 below shows the forecast for Satellite Fire Detection System.

TABLE 5-15
SATELLITE FIRE DETECTION SYSTEM (MAT WFM)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	WFM	Satellite Fire Detection System	–	$195	$312	$90	$187	$250	$250	$250

Risk Mitigation and Control Programs

	Risk Program ID	Risk Program Name	CBR
2	WLDFR-C086	Situational Awareness and Forecasting Initiatives – Satellite Fire Detection	Foundational

The forecast for Satellite Fire Detection was developed using a combination of anticipated vendor costs from the Space Science and Engineering Center (SSEC) and internal labor costs to keep the data feed operational in 2024 through 2027. The 2027 forecast increase as compared to 2024 recorded is driven by vendor contracts and labor costs related to visualization and integration of data into various products available both internally and externally. Additionally, increased costs are required to integrate new satellite data feeds in 2027.[24] For example, NOAA plans to launch a new satellite in 2026 that carries an instrument for fire detection, and we expect to integrate this data into the system in 2027.[25]

10. Weather Stations (Expense MAT WFW; Capital MAT 21B)

a. Overview

PG&E's Weather Station Project supports incremental installation of weather stations and important calibration and maintenance efforts of existing stations to keep the system operational. The Weather Station Project is a foundational activity for Wildfire risk. Data collected by these stations play a foundational role in maintaining situational awareness at all times, and is critical for PSPS execution, reporting, and model development and verification. For example, data from PG&E's weather stations are incorporated directly into the PSPS execution dashboard and data are reviewed live by meteorologists to make PSPS recommendations. PG&E's weather station network consisted of 1,582 stations at the end of 2024 and additional strategic installations are planned through 2030.

Every weather station reports fire weather parameters such as wind speed, wind gust, temperature, and relative humidity at least every 10 minutes with on-demand data every 30 seconds available at most locations. Data from weather stations are made publicly available and uploaded to the National Oceanic and Atmospheric Administration,

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24 See Exhibit (PG&E-4) WP 5-3, line 18.

25 See JPSS Overview, *The Joint Polar Satellite System (JPSS)*, available at: <https://www.noaasis.noaa.gov/POLAR/JPSS/jpss.html> (accessed April 3, 2025).

where they are used as input to global weather model initializations. Each weather station provides local data on or near our assets in real-time and helps improve our forecast model data. As part of the Numerical Weather Prediction program, described in Section B.7, we plan to deploy artificial intelligence and/or machine learning on each weather station to improve forecast quality at each weather station. The weather station project also includes:

- Equipment, labor, project management, environmental reviews, and costs related to permitting required to install incremental weather stations through 2030. Locations for new installations are selected by PG&E meteorologists to improve local situational awareness.
- Annual calibration and maintenance activities required to keep the system operational and data trustworthy. Each calendar year, we perform a physical, on-site calibration to ensure station readings fall within manufacturers' specifications and will calibrate or replace equipment and instruments as required. Most stations are calibrated each year aside from a potential very small minority where site access could be compromised (e.g., road washout) or where access is no longer permitted (e.g., customer refusal).
- Other activities such as: break-fix requests; project management activities; and movement of stations due to undergrounding, refusals, or other optimization requests.

b. Forecast

Tables 5-16 and 5-17 below show the forecast for Weather Stations.

TABLE 5-16
WEATHER STATIONS (MAT WFW/WFM)[(a)]
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	WFW/ WFM	Weather Stations	$111	$145	$99	$2,468	$2,915	$3,753	$3,987	$4,170

	Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-C088	Situational Awareness and Forecasting Initiatives – Weather Station Expense	Foundational

(a) The forecast for Weather Stations is in MAT WFM and should be in WFW. This will be updated in PG&E's post filing errata submission.

TABLE 5-17
WEATHER STATION PROJECT (MAT 21B)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	MAT Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	21B	Weather Stations	$8,315	$7,720	$5,625	$3,956	$1,991	$1,426	$1,205	$1,204	$1,223	$1,153	$1,049

	Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M052	Situational Awareness and Forecasting Initiatives – Weather Station Capital	Foundational

As the station network is nearing full maturity, we plan to install an additional ~100 stations through the 2027-2030 timeframe starting with 30 stations in 2027. The capital costs were derived from 2024 recorded unit costs and carried through 2027. By 2027 we forecast the unit cost per weather station install to be ~$40,000, which represents all-in cost per installation (equipment, labor, program management, permitting, environmental reviews, pole load calculations).[26] The 2027 capital forecast decrease compared to 2024 recorded is driven by less units planned to be installed in 2027 versus 2024.

Expense costs associated with the Weather Station Project are driven by annual calibration, maintenance, and break-fix activities. Costs are a function of the per-unit calibration costs, maintenance costs, the volume of units that require break-fix, the total calibration volume, and the volume of stations that need to be relocated (optimized). Stations are optimized due to safety issues accessing the station or due to distribution undergrounding where local weather stations observations are not as critical. The baseline 2027 expense forecast was developed using the 2023-2024 historical unit cost to calibrate weather stations, then escalating the costs and units to 2027 in addition to layering in other factors.[27] For example, we anticipate a higher volume of stations that will need to be relocated and optimized due to accelerated undergrounding efforts and a higher volume of replacement equipment as stations age. Thus, the 2027 forecast increase as compared to 2024 recorded is driven by unit-cost escalation, increased unit volume, increased part replacements to keep stations operational, and a projected increase in the volume of weather stations that will need to be relocated (optimized) due to increased undergrounding line miles.

11. Distribution Fault Anticipation (Capital MAT 3UD)

a. Overview

The Distribution Fault Anticipation (DFA) sensor is a type of distribution grid sensor located at substations which individually and in

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26 See Exhibit (PG&E-4), WP 5-3, line 17. See Exhibit (PG&E-4), WP 5-45, line 4.

27 See Exhibit (PG&E-4), WP 5-46.

combination with other sensors, provide real-time monitoring capability of the grid. The DFA sensors measure volts, amps, and arcing conditions, and monitor magnitude, phase, harmonics, real and reactive power, and cycle-to-cycle deltas in these values. They also cluster and categorize events and generate waveforms. This high-resolution data is matched with a historical distribution event waveform library provided by the leading vendor of the technology to accurately categorize the type of event. Since the sensor is installed at a single measurement point (the substation), it cannot by itself determine location of the event in the circuit. However, the approximate location can be determined by combining DFA event data with Line Sensor fault data and CYME circuit model information. PG&E has integrated DFA alerts into Foundry GDAT to streamline DFA data analysis which can result in focused field investigations to locate and remediate wildfire risks.

The Distribution Fault Anticipation sensor program is a foundational activity for Wildfire risk. The DFA sensor and Line Sensor in combination can identify conditions such as fault induced conductor slap and arcing elbows. DFA sensor data in combination with SmartMeter™ event data has been shown to identify high-impedance fault conditions such as Series Arcing which can be a precursor to ignition. Identifying these conditions proactively enables PG&E to mitigate risks that can otherwise cause wildfire ignition and/or unplanned outages.

b. Forecast

Table 5-18 below shows the forecast and recorded costs for DFA.

TABLE 5-18
DISTRIBUTION FAULT ANTICIPATION (MAT 3UD)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	3UD	Distribution Fault Anticipation	$178	$4,595	$5,586	$180	$2,214	$2,998	$2,715	$2,715	$2,715	$2,715	$2,715

	Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M045	Situational Awareness and Forecasting Initiatives – DFA	Foundational

PG&E plans to expand DFA sensor coverage to the remaining HFTD area circuits, deploying the technology on approximately 15 circuits per year as defined in the 2026-2028 WMP.

The forecast for the DFA program (MAT 3UD) was developed using 2024 recorded unit costs and assumes deployment of 15 units each year.[28] This forecast supports the design, deployment, and commissioning of DFA sensors.

12. Early Fault Detection (Capital MAT 3UE)

a. Overview

The Early Fault Detection sensor (or RF sensor) is a type of Distribution Grid Sensor which listens for Radio Frequency signals generated by partial discharge arcing on Alternating Current (AC) circuits and use precise time measurement of events to locate the source of the disturbance along the conductor. The sensors are deployed approximately 3 miles apart on a circuit and can provide sub-span (30 feet) locational accuracy.

RF sensors can successfully identify conditions such as broken conductor strands, birdcaged conductors, cracked/melted/squatting insulators, and broken tiewires. The ability to identify these issues prior to failure and mitigate them through normal maintenance tags makes the technology a valuable tool for incipient fault detection to reduce wildfire ignition risks. Additional product development by the vendor (at no additional cost to PG&E), may also have the potential to reduce inspection costs through real-time monitoring and remediation of incipient issues. PG&E plans to integrate early fault detection alerts into its Foundry GDAT platform to streamline sensor data analysis.

The Early Fault Detection Sensors Program is a foundational activity for Wildfire risk. As described above, sensors provide a critical line of defense in preventing ignitions by providing frequent information to PG&E on any maintenance needs.

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28 See Exhibit (PG&E-4), WP 5-47, lines 20-30.

b. Forecast

Table 5-19 below shows the forecast and recorded costs for Early Fault Detection.

TABLE 5-19
EARLY FAULT DETECTION (MAT 3UE)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted					Forecast					
			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	3UE	Early Fault Detection	-	$36	$4,361	$887	$2,799	$6,725	$5,450	$5,440	$5,601	$5,018	$4,149
			Risk Mitigation and Control Programs										
	Risk Program ID		Risk Program Name					CBR					
2	WLDFR-M044		Situational Awareness and Forecasting Initiatives – EFD					Foundational					

The forecast for Early Fault Detection was developed using 2024 recorded costs, as well as an estimated change in unit cost starting 2025 based on an average lower unit cost.[29] Requested funding in this GRC will enable ramped up deployment of RF sensors in approximately 180 locations per year (2027-2030) as defined in the 2026-2028 WMP. An average circuit will require between 30-40 sensors based on circuit length. This forecast supports the design, deployment, and commissioning of EFD sensors.

13. Line Sensors (Capital MAT 3UL)

a. Overview

The Line Sensor is a type of Distribution Grid Sensor which individually and in combination with other sensors, provide real-time monitoring capability of the grid.

Line sensors are conductor-mounted devices that are able to detect larger overcurrent conditions (faults) and can moderately categorize and localize the location of the condition. Medium voltage line sensors (MV sensors) harvest power from the conductor and continuously measure current in real-time and report events as they occur. MV sensors are ideal for main lines and tap lines with sufficient load current. Battery powered line sensors (otherwise known as Communicating Current Fault Indicators or CFCIs) report events as they occur but otherwise communicate to its back-end management system once a day. CFCIs are ideal in low current sections of the circuit where there is insufficient line current to power the sensor.

When fault events (e.g., momentary faults, permanent faults) are detected, line sensors send alerts to be displayed on PG&E's Control Center application - Advanced Distribution Management System. Fault event information such as root mean square current values and wave forms as well as power-on/power-off events are also sent to PG&E's Foundry GDAT (Grid Data Analytics & Technology) platform. GDAT uses the line sensor data along with circuit model information from

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29 See Exhibit (PG&E-4), WP 5-47, lines 32-42.

CYME Power Engineering software to estimate the location of disturbance.

Line sensors support post-outage investigations for unknown cause outages – these include conditions such as animal, vegetation, and foreign object contact as well as sagging conductors with potential for phase-to-phase contact. Line Sensors also work complementarily with Distribution Fault Anticipation sensors to identify incipient conditions such as fault induced conductor slap and arcing underground elbows. The Line Sensor Program is a foundational activity for Wildfire risk. By proactively detecting failing conditions before they continue to degrade, these sensors enable PG&E to address latent or incipient issues in their early stages before they cause an ignition that leads to a wildfire.

b. Forecast

Table 5-20 below shows the forecast and recorded costs for Line Sensors.

TABLE 5-20
LINE SENSORS (MAT 3UL)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	3UL	Line Sensors	$2,416	$3,966	$2,254	$3,008	$1,669	$2,164	$1,881	$1,881	$1,881	$1,881	$1,881

	Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M046	Situational Awareness and Forecasting Initiatives – Line Sensors	Foundational

PG&E plans to expand line sensor coverage to the remaining HFTD area circuits at a rate of approximately 50 circuits (240 locations)/year as defined in the 2026-2028 WMP.

The forecast for the Line Sensor program (MAT 3UL) was developed using 2024 recorded costs with an estimated change in unit cost starting 2025 based on a lower cost product mix.[30] This forecast supports the design, deployment, and commissioning of line sensors. The 2027 forecast is an increase from 2024 recorded costs because PG&E plans to install more line sensors in 2027 (240) compared to 2024 (194). However, this cost increase is moderated by reduced unit costs.

14. Discontinued and Completed Wildfire Mitigation Programs

The recorded cost data presented in this chapter (2020-2024) includes $2.9 million for two wildfire mitigation pilots that were forecast in the 2023 GRC and recorded to the WMBA, but are not forecast for the 2027 GRC. These pilots include Rapid Earth Fault Current Limiter and Sensor IQ.[31] Also included in this chapter are recorded costs for two other programs that were discontinued or completed: (1) DTS Fast was not forecasted in the GRC but was piloted and discontinued; and (2) Partial Voltage Detection (Wire Down Detection) was completed.

Rapid Earth Fault Current Limiter (REFCL)

The Rapid Earth Fault Current Limiter pilot (MAT 3UR) tests a wildfire mitigation technology installed on substation transformers, and supported with additional field equipment, to provide line-to-ground protection by mitigating ignitions from faults such as wire down or tree contacts. PG&E implemented this technology at Calistoga substation beginning in 2018. PG&E encountered challenges in evaluating the technology's effectiveness due to delays in commissioning the program, including equipment failure, extended load time of equipment, and need to procure additional equipment to stabilize the system. While we are in the process of evaluating an additional site for Rapid Earth Fault Current Limiter deployment, PG&E is not forecasting any work in the 2027 GRC period and will not forecast any additional work until the existing

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30 See Exhibit (PG&E-4), WP 5-47, lines 44-54.

31 These programs are described in PG&E's 2023 GRC Testimony, Exhibit (PG&E-4), Ch. 4.3.

deployment has been operational long enough to calculate the effectiveness of wildfire risk reduction.[32] In the meantime, we will continue to invest in other viable wildfire mitigation alternatives including Enhanced Powerline Safety Settings and Down Conductor Detection Sensor.

Sensor IQ

The Sensor IQ pilot used software that works with existing SmartMeter devices to capture and store high-resolution, real time, and granular data on load, voltage, and outages to enable predictive maintenance data analytics. PG&E evaluated the usefulness of SIQ data as part of the EPIC 3.43 project and came to the conclusion that machine learning models using 5-minute interval data enabled by SIQ did not provide a higher predictive performance in identifying incipient issues than existing 15 minute or 60 minute SmartMeter data. A more effective, long-term and scalable approach would be to use distributed intelligence technologies provided by next generation smart meters which does computation at the edge and report by exception. The Sensor IQ pilot was hence discontinued in 2022.[33, 34]

DTS-FAST

DTS-FAST is a technology developed internally at PG&E. The technology uses fraction-of-a-second technologies to detect an object (such as a falling branch) approaching an energized power line and responds quickly to shut off power before the object impacts the line.

In 2020, PG&E completed a proof of concept in San Ramon, California. The proof-of-concept model confirmed the technology would meet the detection, speed, and signal confirmation requirements for subsequent testing through a pilot.

DTS-Fast was piloted in 2021 and was discussed though not forecasted in the 2023 GRC.[35]

DTS Fast was discontinued because it would require placement of additional sensors on distribution poles for a sole purpose of object detection to

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32 See Exhibit (PG&E-4), WP 5-45, line 16.

33 The recorded costs for Sensor IQ are in Ch. 23; See Exhibit (PG&E-4), WP 23-3 line 10. The recorded costs for Sensor IQ are imbedded in the Wildfire Team Support costs.

34 See Exhibit (PG&E-4), WP 5-45, line 7.

35 A. 21-06-021, Exhibit PG&E-4, p. 4.3-64, line 10 to pp. 4.3-65, line 10 (Feb. 25, 22).

enable shutting off the power before an object strikes the line. We concluded a more comprehensive approach that would provide both reliability and wildfire benefits was combination of Early Fault Detection (EFD), Distribution Fault Analysis (DFA) and Line Sensors as discussed above.[36]

Partial Voltage Detection (Wire Down Detection)

As part of its effort to enhance customer/public safety and further mitigate wildfires, PG&E initiated the Partial Voltage Detection (formerly referred to as Enhanced Wire Down Detection) project in 2018.

In the initial phase of the project in 2019, the technology was deployed to 4.5 million single-phase SmartMeters™. The second phase began in 2020 and deployed the technology to 365,000 three-phase meters.[37] This project was completed in 2021.[38]

Table 5-21 summarizes the recorded amounts for these programs.

TABLE 5-21
DISCONTINUED AND COMPLETED WILDFIRE MITIGATION PROGRAMS
(THOUSANDS OF NOMINAL DOLLARS)

Line #	MAT	Program	Recorded Adjusted 2020	2021	2022	2023	2024
1	3UR	REFCL	$4,798	$(2,022)	$75	$72	$4
2	AB#	Sensor IQ	1,900	1,200	27	-	-
3	21A	Wire Down Detection	1,216	608	7	0	-
4	21#	DTS-FAST	-	4,220	1,338	815	-

C. Compliance

1. Deferred Work Analysis

The 2023 GRC Decision (OP 4) requires PG&E to continue following the directives in the Deferred Work Settlement and submit the related data in its

36 See Exhibit (PG&E-4), WP 5-45, line 8.

37 A.21-06-021, Exhibit PG&E-4, p. 4.1-27, line 22 to pp. 4.1-28, line 2 (Feb. 25, 22).

38 See Exhibit (PG&E-4), WP 5-45, line 6.

2027 GRC.[39] The Deferred Work Settlement requires PG&E to include testimony on deferred work if the following criteria are met:

1) The work was requested and authorized based on representations that it was needed to provide safe and reliable service;
2) PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and
3) PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.

For work covered in this Chapter, PG&E applied these criteria as explained in Analysis of "Deferred Work" discussion set forth in the Electric Distribution Forecast Summary and Investment Planning chapter.[40] This analysis is presented in the workpapers supporting that chapter.[41]

Based on this analysis, no work included in this Chapter was identified as "deferred work" under the terms of the Deferred Work Settlement.

D. Accounts

1. Retain Accounts without Modifications

a. Wildfire Mitigation Balancing Account (WMBA)

In the 2023 GRC D.23-11-069, the Commission directed PG&E to establish a one-way balancing account to record costs for wildfire mitigations.[42] In this rate case period, PG&E is proposing to retain the WMBA as requested in Exhibit (PG&E-4) Chapter 4, Section E. PG&E summarizes its request to retain, modify, or discontinue existing cost recovery mechanisms as described in this exhibit and associated revenue requirements in Exhibit (PG&E-10), "Results of Operations," Chapter 16 "Balancing Accounts."

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39 Pursuant to D.23-11-069, p. 900, OP 4, "Pacific Gas and Electric Company shall continue to follow the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC, subject to the limitations of Public Utilities Code Section 8386.3, which restricts the diversion of revenues authorized for certain wildfire mitigation activities."

40 See Exhibit (PG&E-4), Ch. 2, Section E.1.b.

41 See Exhibit (PG&E-4), WP 2-19.

42 See D.23-11-069, p. 910, Ordering Paragraph 39, Section 4.24 Electric Distribution Ratemaking.

PG&E proposes that the costs for the wildfire mitigations in this chapter be recorded to the Wildfire Mitigation Balancing Account (WMBA). A summary of PG&E's total WMBA forecast is in Exhibit (PG&E-4) Chapter 4 Section E.

E. Conclusion

Based on the demonstration above and on the evidence presented in the associated attachments and workpapers to this chapter, PG&E respectfully requests that the Commission:

1) Adopt the expense forecasts in Section A.2, Table 5-1; and
2) Adopt the capital forecasts in Section A.2, Table 5-2.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 6

WILDFIRE OPERATIONAL MITIGATIONS (PSPS, EPSS, AND CUSTOMER BATTERY PROGRAMS)

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
WILDFIRE OPERATIONAL MITIGATIONS (PSPS, EPSS, AND CUSTOMER BATTERY PROGRAMS)

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 6
WILDFIRE OPERATIONAL MITIGATIONS (PSPS, EPSS, AND CUSTOMER BATTERY PROGRAMS)

A. Introduction and Summary

1. Overview

The purpose of this chapter is to demonstrate that Pacific Gas and Electric Company's (PG&E or the Company or the Utility) forecasts of expense and capital expenditures to support Public Safety Power Shutoff (PSPS) activities, Enhanced Powerline Safety Settings (EPSS) activities, and the Customer Battery Program are reasonable and should be approved.

PSPS and EPSS are two key operational mitigation programs that provide weather-driven response to forecasted fire danger. Due to its significant potential disruption to electricity delivery and the resulting safety impacts, PSPS is considered a mitigation measure of last resort. Conversely, EPSS is a protective strategy that allows line protection devices, such as line reclosers and circuit breakers, to respond more rapidly to the need to de-energize lines.

The Customer Battery programs directly mitigate the negative customer impacts of turning off power for wildfire safety through the PSPS and EPSS programs by providing a suite of backup power offerings which prioritize customers who are most heavily impacted by PSPS and EPSS outages.

2. Summary of Request

PG&E respectfully requests that the Commission:

- Adopt the expense forecasts in Section A.2, Table 6-1;
- Adopt the capital expenditure forecasts in Section A.2, Table 6-2;
- Adopt the specific post Test-Year attrition proposed for the Customer Battery Programs as described in Section D; and
- Approve the discontinuation of the Microgrid Memorandum Account (MGMA) as described in Section F.

Forecasts in this chapter are shown with no escalation for all expense and capital totals. PG&E will offset escalation through work execution efficiencies to improve affordability.

TABLE 6-1
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	Program	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	Workpaper Reference
1	AB	Misc Expense	PSPS	$337	$3,272	$6,599	$670	$11	–	–	–	WP 6-3, Line 2
2	BA	E Dist Operate System	EPSS	–	2,998	709	1,140	1,549	$5,410	$4,823	$4,823	WP 6-3, Line 14
3	BF	E T&D Patrol/Insp	EPSS	–	–	868	51	48	–	–	–	WP 6-3, Line 29
4	BH	E Dist Routine Emergency	EPSS	–	12,658	12,877	10,277	10,771	13,885	13,885	13,885	WP 6-3, Line 20
5	DD	Provide Field Service	EPSS	–	–	610	258	148	722	643	643	WP 6-3, Line 23
6	FZ	E Dist Planning & Ops Engineer	EPSS	–	2,046	12,988	4,844	5,138	9,564	8,526	7,601	WP 6-3, Line 5
7	GC	E Dist Subst O&M	EPSS	–	437	3,993	211	55	192	192	153	WP 6-3, Line 17
8	HG	Elec Trans Ops Engr & Tech	EPSS	–	–	3,393	83	174	–	–	–	WP 6-3, Line 32
9	HX	E T&D Automation & Protection	EPSS	–	–	1,473	73	57	289	257	229	WP 6-3, Line 26
10	IG	Manage Var Bal Acct	PSPS	–	313	468	1,130	1,184	12,763	11,379	11,672	WP 6-3, Line 8
11		Processes	EPSS	–	502	47,076	33,644	39,122	36,110	34,947	30,997	WP 6-3, Line 9
12			Battery	18,655	19,905	28,351	45,876	28,858	58,327	55,749	69,610	WP 6-3, Line 10
13	WF	Wildfire Mitigation	PSPS	90,172	42,096	8,427	11,969	35,879	30,110	30,439	47,763	WP 6-3, Line 35
14			PSPS Total	$90,509	$45,682	$15,495	$13,769	$37,074	$42,873	$41,817	$59,435	
15			EPSS Total	–	$18,640	$83,986	$50,581	$57,063	$66,171	$63,274	$58,331	
16			Battery Total	$18,655	$19,905	$28,351	$45,876	$28,858	$58,327	$55,749	$69,610	
17			Grand Total	$109,164	$84,227	$127,832	$110,227	$122,994	$167,371	$160,840	$187,377	WP 6-3, Line 37

Note: The values reflected in the tables in this chapter may vary from the initial Results of Operations (RO) Model provided with PG&E's GRC filing due to timing differences. The RO Model will be updated to incorporate these errata in a future submission.

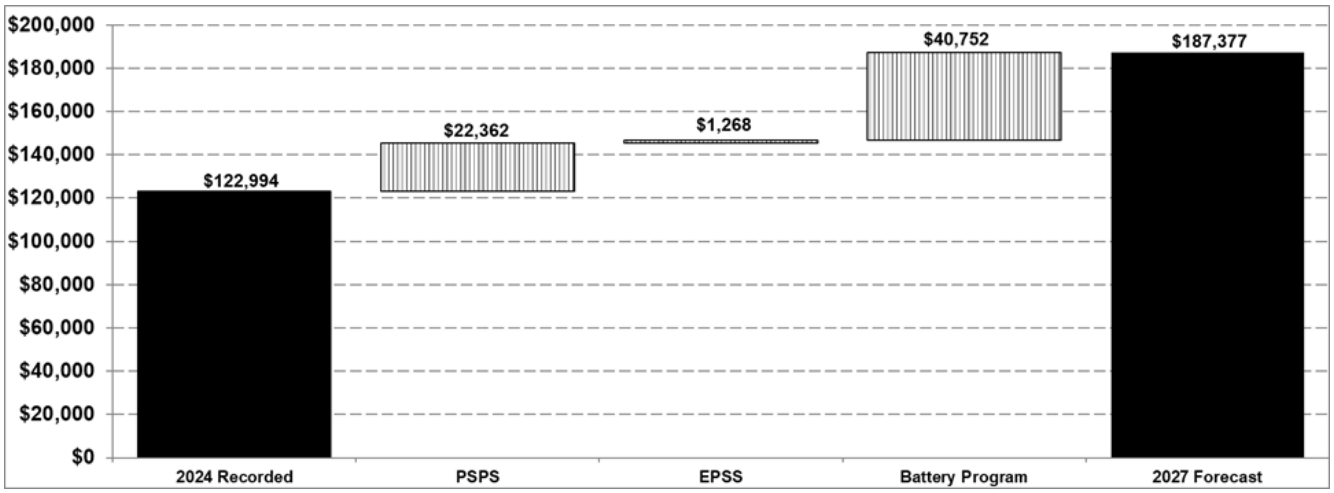
TABLE 6-2
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	Program	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030	Workpaper Reference
1	3U	Inst/Rpl WildFire Mitgt Eqpmnt	EPSS	–	–	$1,112	$12,743	$12,937	$10,793	$10,506	$10,253	$10,902	$9,874	$8,158	WP 6-46, lines 24
2			PSPS	79,529	43,399	24,492	14,054	7,030	5,168	4,196	2,096	2,130	2,008	1,826	WP 6-47, lines 26 & 27
3	09	E Dist Automation & Protection	EPSS	–	2,742	12,183	13,887	18,792	20,466	17,295	17,278	17,556	16,552	15,057	WP 6-46, line 10
4	49	E Dist Reliability Ckt/Zone	EPSS	–	–	3,750	6,541	13,095	18,211	16,455	15,760	19,934	18,305	22,556	WP 6-46, line 18
5	48	E Dist Subst Repl Other Equip	EPSS	–	–	990	4,530	5,498	4,007	5,298	9,155	3,000	3,000	3,000	WP 6-46, line13
6	21	Misc Capital	EPSS	–	–	–	–	2,007	2,530	2,138	2,136	2,170	2,046	1,862	WP 6-46, line 5
7			Battery	–	–	–	–	–	–	–	13,000	26,000	26,000	26,000	WP 6-46, line 6
8	63	E T&D Control System/Facility	EPSS	–	–	–	1,680	1,971	–	–	–	–	–	–	WP 6-46, line 21
9	05	Tools & Equipment	EPSS	–	–	–	90	190	–	–	–	–	–	–	WP 6-46, line 2
10			PSPS Total	$79,529	$43,399	$24,492	$14,054	$7,030	$5,168	$4,196	$2,096	$2,130	$2,008	$1,826	WP 6-48, line 5
11			EPSS Total	–	$2,742	$18,036	$39,472	$54,491	$56,007	$51,693	$54,583	$53,562	$49,777	$50,632	WP 6-47, line 24
12			Battery Total	–	–	–	–	–	–	–	$13,000	$26,000	$26,000	$26,000	WP 6-49, line 3
13			Grand Total	$79,529	$46,141	$42,528	$53,525	$61,522	$61,175	$55,889	$69,679	$81,692	$77,785	$78,459	

a. Expense

Figure 6-1 provides an expense walk identifying key drivers for the difference in the 2027 forecast as compared to 2024 recorded. Each driver is summarized below.

FIGURE 6-1
EXPENSE WALK 2024-2027
(THOUSANDS OF NOMINAL DOLLARS)



The increase to PSPS program costs in 2027 forecast compared to 2024 recorded are primarily due to favorable weather conditions in 2024 relative to broader historical weather data used for determining the 2027 forecast. While we did execute six PSPS events in 2024, the scope of the PSPS events were relatively small in comparison to past years with extreme weather conditions such as 2019 and 2020. The 2027 forecast incorporates extreme weather years in the multiyear lookback. PG&E's updated forecast methodology for PSPS events also utilizes PG&E's current PSPS protocols and system configuration against historical weather data. The historical weather data captures some of the largest weather events in PSPS program history which increases the average forecasted cost in comparison to 2024.

The EPSS expense program is forecasted to be relatively stable for the 2027 GRC timeframe. Forecasts in this chapter for EPSS are influenced by a number of factors. EPSS program continues to evolve and costs can fluctuate from year to year based on weather-related

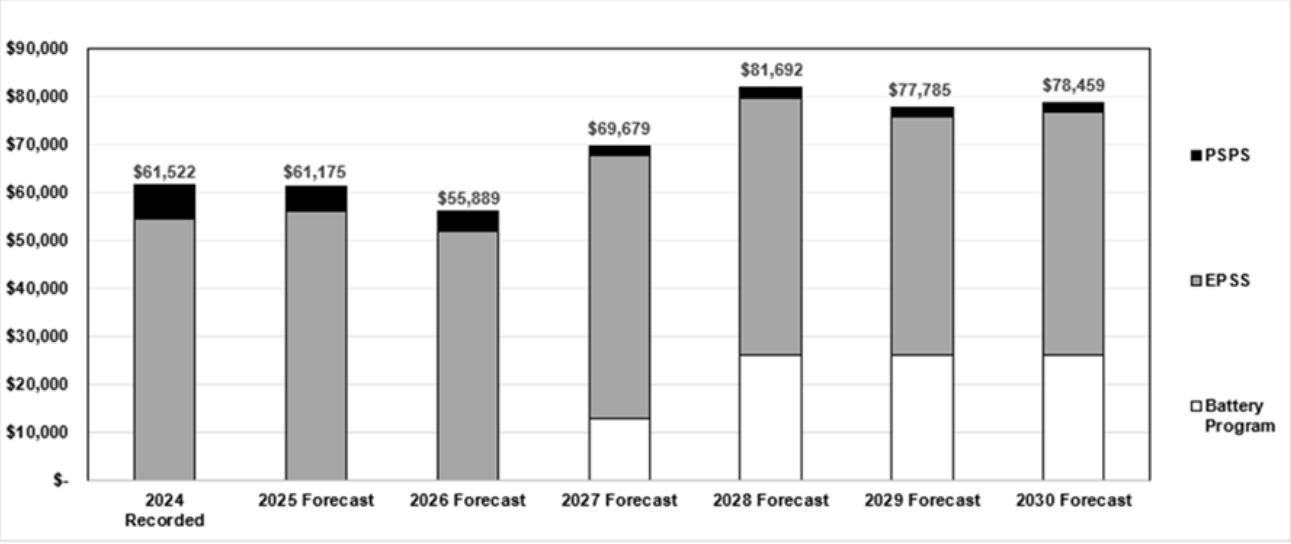
factors beyond PG&E's control. Additionally, as a still nascent program, climatological changes could affect wildfire risk across the service areas and may require adjustments to EPSS program strategies to maximize the continued effectiveness of the wildfire mitigation control. Therefore, the forecast is reflective of the need to continue to build out EPSS protection capability, while appreciating that as the program matures, the ability to reduce outage activity and/or duration of outages should allow for savings in future years.

Lastly, the forecast increase in the Customer Battery Program is driven by increases in permanent battery direct install and rebate programs as funding expires for the predominant, state-wide permanent battery incentive program.

b. Capital

Figure 6-2 provides a capital walk that depicts the key drivers for the difference in the 2027 forecast versus 2024 recorded. Each key driver is summarized below.

FIGURE 6-2
CAPITAL WALK 2024-2030
(THOUSANDS OF NOMINAL DOLLARS)



PSPS forecast costs decrease due to fewer sectionalizing units being installed.

The EPSS capital program continues to mature since the inception of the EPSS program, with the expansion of targeted programs are reflective of the need to continue to install protection equipment to expand EPSS protection capability, as well as support targeted mitigation programs aimed at reducing the likelihood of outage activity requiring EPSS protection. Costs can fluctuate from year to year based on the mix of work and complexity of work performed, as well as weather driven factors that can influence where wildfire risk is greatest—requiring EPSS protection—across the service area. Following a forecast increase, those costs are forecast to remain relatively stable for the 2027 GRC timeframe.

The increase in the capital Customer Battery Program forecast is driven by PG&E's plans to implement a utility-owned battery program called the Customer Battery Infrastructure (CBI) program. This program will install utility owned and maintained permanent batteries on-site for residential customers that are heavily impacted by wildfire safety outages, with a priority for customers with unique needs like low-income customers and those with medical devices.

3. Risks Addressed

PG&E's forecast for Wildfire Operational Mitigations addresses the Electric Distribution-related Risks described in Table 6-3.[1] A summary table of the program names, foundational activities, risk mitigation and/or control identification and cost-benefit ratios (CBRs) for this chapter is presented in Table 6-4 below.

Each program in this chapter identifies the risk addressed, the cost-benefit ratio (CBRs) when applicable, and describes why the risk mitigation and control work is necessary and justified.

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1 For additional information on these risks, see Exhibit (PG&E-4), Ch. 3.

TABLE 6-3
RISKS ADDRESSED BY WILDFIRE OPERATIONAL MITIGATIONS

Line No.	Risk Name	Risk ID	Risk Description
1	Wildfire with PSPS and EPSS	WLDFR, WPSPS, WEPSS	The Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands or environment originating from PG&E assets or activities. In the near term due to the use of Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS) we have also defined Post PSPS/EPSS Wildfire Risk as Wildfire Risk with PSPS and EPSS. This does account for the benefits and consequences of operational mitigations such as PSPS and EPSS.
2	Failure of Electric Distribution Overhead Assets	DOVHD	This risk is defined as lack of remote operational functionality that may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.

TABLE 6-4
FOUNDATIONAL ACTIVITIES, RISK MITIGATIONS AND RISK CONTROL PROGRAMS

Line No.	MAT	Program Name	Risk Program ID(s)	CBR (2027-2030)
Risk Mitigations				
1	WFN	PSPS	WLDFR-M001	25.3
2	WFP			
3	BAF	EPSS	WLDFR-M020	33.8
4	BAH			
5	BHE			
6	DD#			
7	FZA			
8	FZE			
9	GC2			
10	HXA			
11	IG#			
12	09B			
13	21#			
14	3US			
15	48D			
16	49B			
17	49D			
18	49E			
19	49G			
20	IG#	Temporary Generation	WPSPS-M006	5.7
21	IG#	Portable Battery	WEPSS-M011, WPSPS-M003, DOVHD-M031	0.4
22	IG#	Permanent Battery	WEPSS-M012, WPSPS-M004, DOVHD-M032	4.2
23	IG#	RSI Battery	WEPSS-M013, WPSPS-M005, DOVHD-M033	1.7
24	IG#	Generator and Battery Rebate Program (GBRP)	WEPSS-M017, WPSPS-M008, DOVHD-M039	23.6
25	21#	BTM Capital Battery Program	WEPSS-M018, WPSPS-M009, DOVHD-M040	1.5
26	3UP	PSPS Granular Sectionalizing	WPSPS-M011	Step 3 Exempt
Foundational Activities				
27	IG#	Support Labor (PSPS Customer Resiliency Non-Event)	WPSPS-M007	Foundational

Note: ***Step 3 Exempt*** indicates this program is exempt from Step 3 Supplemental Analysis in the GRC and does not require a CBR. See Exhibit (PG&E-4), WP 3-25 for details. For more information on Step 3 Supplemental Analysis, see D.22-12-027, Appendix A, p. A-17, No. 28.

In addition, all programs in this chapter are wildfire mitigations and/or controls which contribute to climate resilience because they address wildfire risk. For more information the relationship between this General Rate Case filing and PG&E's climate resilience plans, see Exhibit (PG&E-2), Chapter 1.

B. PSPS Forecast [Shawn Holder]

The PSPS forecast is grouped into three categories: PSPS Events, PSPS Programs, and Sectionalization.

PSPS Events include costs directly tied to the proactive de-energization following a determination of weather-related imminent threat to power line assets and increased risk of catastrophic wildfire.

PSPS Programs include the costs for all activities supporting and improving the program not directly connected to PSPS events. These costs include PSPS program team as well as the PSPS projects to that help improve the decision-making process, information gathering, and Temporary Generation processes when PG&E considers initiating a PSPS event.

Lastly, Sectionalization includes the costs for installing sectionalizing devices which gives the flexibility to only de-energize a portion of the line with the at-risk asset, rather than the entire line. This means that customers may remain in-service while still de-energizing the necessary portions of the line during PSPS events.

1. PSPS Events (Expense MWC IG, WF)

a. Overview

Our objective when initiating a PSPS event is to keep our customers safe. High winds can cause tree branches and debris to contact energized electric lines, which can potentially lead to a wildfire. As a result, we may need to turn off power during severe weather to help prevent wildfires. We know that losing power disrupts lives, which is why we are working year-round to make our system safer and more resilient and reduce the impact of PSPS for our customers and communities.

PSPS event costs consist of activities directly associated with PG&E's proactive de-energization of its 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 associated with activating the Emergency Operations Center (EOC), sending customer and agency notifications, de-energizing power lines to reduce the risk of those lines igniting a wildfire during a weather-related event, and re-energizing the lines once the event has ended and it is deemed safe.

The categories of cost incurred per PSPS event are broken down into the following:

- EOC Support – The EOC is comprised of a multi-disciplinary team of PG&E employees who assume emergency response positions consistent with the Incident Command System;
- IT – Coordinates the response of PG&E's IT resources and systems in support of all stages of PSPS;
- Aviation Services – These include the flight costs associated with aerial patrols of de-energized transmission and distribution lines to ensure it is safe re-energize the lines;
- Ground Patrols – These include the costs of internal and contract crews that are utilized to patrol and inspect the de-energized lines, to ensure that it is safe to re-energize the lines and restore power to customers;
- Customer Outreach – During PSPS events, PG&E's Customer teams provide key support to customers and partner agencies;
- 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 PG&E's electric distribution system. The branch also provides information on customer outages and field operational challenges to the EOC;
- Community Resource Centers (CRCs) – To minimize public safety impacts during a PSPS event, PG&E opens CRCs in potentially impacted counties and tribal communities. CRCs provide customers and residents a safe location to meet their basic power needs, such as charging medical equipment and electronic devices;

- In-Event Vegetation Management – Beginning in 2020, PG&E began investigating whether vegetation mitigation work can occur to prevent de-energization of a line during a PSPS event. This cost is for expedited vegetation work that could potentially avoid de-energizing a line;
- Temporary Generation – To enable some community resources to continue serving the surrounding population during a PSPS event, temporary generation can be used to power critical facilities or microgrids, providing electricity to those who would otherwise be out of power. Temporary generation can involve deploying mobile generators and utilizing existing microgrids; and
- Other – Includes various categories to support PSPS events such as, Hydro Support to provide EOC leads with a list of potentially impacted PG&E Power Generation managed facilities and business continuity plans due to a PSPS event; and staging and mobilizing response resources, as necessary.

The scope and duration of a PSPS event is based upon PG&E's near-term modeling of weather forecasts and vegetation fire potential. PG&E's models develop near-term forecasts four times a day. These forecasts, in conjunction with other global and local forecasts from external agencies, are evaluated by members of PG&E's Fire Science and Meteorology teams. These teams determine if there is a heightened outage risk from a wind event, and if there is a potential for large wildfires if there is an ignition. If severe weather conditions exist, PG&E determines the potential scope of a PSPS event by identifying which distribution and transmission facilities, if any, are within the area forecast to be impacted by the weather event and therefore require de-energization. PG&E's Meteorology team closely monitors changing forecasts and conditions, updates the PSPS Incident Command team in the event of any changes, and continually revises the scope of a possible event, both in terms of the estimated magnitude and timing. Forecast updates may add or remove additional areas from the scope of a PSPS event or change the timing of a PSPS event.

One of the key components of PG&E's PSPS response plan is the EOC. The EOC is tasked with executing PSPS events in compliance with the CPUC's Guidelines[2] and in a manner that minimizes disruptions to PG&E's customers.

PG&E has developed a process for determining whether to activate the EOC and what to do when the EOC is activated for a PSPS event. The process includes: (1) monitoring weather conditions before the EOC is activated; (2) activating the EOC when conditions indicate a PSPS event may become necessary; (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 to begin patrolling affected circuits and re-energizing the power grid.

PG&E understands that PSPS events cause significant disruptions to our customers, and we aim to reduce the size and duration of these events. As described in Chapter 5 of this exhibit, we are making efforts to mitigate PSPS impacts to PG&E's customers by using advanced meteorology models to forecast wildfire risk conditions more granularly, applying improved analyses to determine which portions of PG&E's electric system face high fire risk, and improving switching and sectionalization such that PSPS events affect smaller portions of the grid and less customers. Our goal, in addition to adherence to CPUC guidance,[3] is to conduct inspections of the de-energized power lines prior to re-energization and restoring service to 100 percent of PSPS-affected customers within 24 hours of the "weather all clear" declaration. We continue to work on improving PG&E's coordination with state, local, and community agencies, and to provide extensive

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2 Resolution ESRB-8 (Issued July 16, 2018), Decision (D.)19-05-042, D.20-05-051, D.21-06-034, D.21-06-014.

3 Resolution ESRB-8, D.19-05-042, D.20-05-051, D.21-06-034, D.21-06-014.

information and support to customers before, during, and after PSPS events.

In 2024, PG&E used improved scoping techniques and mitigation strategies to significantly reduce the size of our PSPS events. We performed a lookback analysis to quantify the impacts of our latest PSPS protocols and mitigations. The analysis uses a 14-year lookback to quantify the expected customer impacts. This analysis shows that our latest PSPS protocols and mitigations reduce the number of customers impacted by over 55 percent when compared to the number of actual customers impacted by the same weather conditions. For instance, the PSPS event from October 26, 2019 to November 1, 2019 was PG&E's largest PSPS event. Using the 2024 PSPS protocols and mitigations, approximately 500,000 (or 50 percent) customers would have avoided de-energization for the same weather event.

The PSPS Events Program is a mitigation for wildfire risk. PSPS Events directly mitigates wildfire risk by evaluating whether to proactively de-energize a portion of PG&E's 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 PG&E's above-ground power lines, suggesting a heightened risk of catastrophic wildfire.

b. Forecast

Table 6-5 below shows the recorded and forecast amounts for PSPS Events.

TABLE 6-5
PSPS EVENTS (MATS IG#, WFP)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	IG#	CRC BUPS	–	$159	$154	–	–	–	–	–
2	WFP	PSPS Event Expense	$80,703	$35,313	3	$5,556	$25,864	$20,301	$21,087	$38,819
3		Total	$80,703	$35,472	$156	$5,556	$25,864	$20,301	$21,087	$38,819

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
4	WLDFR-M001	PSPS	25.3

The 2027 forecast for PSPS events was developed by taking the average of the estimated PSPS cost per year in 2017-2023 using the most recent PSPS protocols and procedures and applying it to the actual weather that occurred during that period.[4] This was calculated by applying the lookback analysis of the deenergized High Fire Risk Area (HFRA) miles for PSPS events per year and multiplying by the average cost per mile in 2021. Utilizing the lookback as the forecast methodology, would have reduced 2019 recorded from $178.8M to the estimated lookback of $82.7 million. The 2027 forecast is an increase compared to 2024 recorded due to smaller weather footprints for PSPS events in 2024 compared to the 2017- 2023 lookback analysis (which is the basis for our 2027 forecast).

PSPS events are based on weather, which cannot be predicted. If PSPS events do not develop that meet or exceed the forecast, and the WMBA is underspent, PG&E will return WMBA funding back to ratepayers, as it did in 2023 when the WMBA expense was underspent.[5] The forecast shown for years 2025 and 2026 reflect a lower amount from 2027 due to internal budget constraints within the company. If PG&E experience extreme weather years in 2025 and 2026, PG&E will reprioritize funding to the PSPS events as needed.

2. PSPS Programs (Expense MWCs WF, and IG)

a. Overview

Our PSPS Program aims to minimize the impact of PSPS by strengthening our overall event response, ensuring PG&E and our customers are prepared, and improving the tools and technologies we rely on to scope and manage PSPS events. Unlike the PSPS Events, the PSPS Program represents preparedness work regardless of the number of PSPS events that are ultimately required in a given year. Our PSPS Program activities can be generally grouped into three categories: PSPS Projects, PSPS Program Team, and Temporary Generation.

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4 Exhibit (PG&E-4), WP 6-4 line 2.

5 Advice Letter (AL) 7181-E.

- PSPS Projects: PSPS projects aim to build out and improve processes and tools that are critical to PSPS execution. Examples of analyses to improve PSPS processes include:
  - Induction Driven Ignition workflow improvements, designed to quantify and inform PSPS decision making with respect to probability of ignition aimed to reduce the conservatism in the model with increased precision through engineering, scientific, and data model updates;
  - Software module development to perform fault current and energy calculations which determine where a fault occurs on a line, the amount of energy released, and how long it takes for the fault to be detected and cleared. This data is then ingested by the Induction Driven Ignition workflow; and
  - Lookback analysis updates based on latest PSPS thresholds. This analysis is used to evaluate mitigation strategies for high frequency PSPS scope.

Examples of strategic work conducted by the PSPS team to build out and improve PSPS technology and tools include:

- PSPS Viewer and Advanced Distribution Management System (ADMS) – provides the ability to orchestrate the scoping of a PSPS event from planning until the point of de-energization. It translates geographic areas of meteorological fire risk to the distribution assets potentially compromised by hazardous weather conditions;
- PSPS Portal – online platform to share key event and sensitive customer information with Public Safety Partners;
- PSPS Situational Intelligence Platform – provides the primary interface to support PSPS events, connecting PSPS data together across multiple systems for real-time intelligence and post-event reporting; it is a central repository of event data for decision making during events; and
- PSPS FORCE Tool – estimates field resources needed to patrol and restore PSPS events.

- PSPS Program Team: Primary functions of the PSPS Program team include:
  - Building a cross-functional process by collaborating with various teams to build and continuously improve the end-to-end PSPS execution process, including gathering and prioritizing requirements, establishing process handoffs, and conducting tabletop exercises;
  - Establishing and evolving the PSPS decision-making process by working closely with Meteorology and Electric Asset Management to develop and operationalize PSPS thresholds and Officer in Charge (OIC) decisions to support successful execution;
  - Leading the development a fire threat assessment of our service territory focused on identifying areas where an electrical asset could be the source of an ignition that, during a hazardous offshore wind event, results in a catastrophic fire (called PG&E's High Fire Risk Area (HFRA) map);
  - Driving and tracking execution against PSPS regulatory requirements;
  - Managing PSPS event data including design control, system, and reporting for key PSPS data;
  - Developing and leading PSPS training;
  - Supporting every PSPS event, including preparation and submission of CPUC post-de-energization reports; and
  - Leading the PSPS Projects' process improvement activities.
- Temporary Generation Program: The Temporary Generation Program mitigates customer outages during PSPS events by utilizing procured temporary generation at safe-to-energize customer locations. The four primary workstreams where temporary generation is used are: Substation microgrids; distribution microgrids (DMG); Back-up Power Support (BUP); and Customer Resource Centers (CRC). The program costs include equipment rental, labor, transportation, and regular wellness checks. If a location is determined to be in scope, resources are deployed to the

site to start the engine(s). These in-event operating cost are not included in the pre-staging forecast cost but are allocated directly to emergency event orders to operate the temporary generators i.e., fuel, labor, etc.

Below is a brief description of each of the four temporary generation workstreams:

- Substation Microgrids: Site temporary generation (TG) at safe-to-energize substations to support safe-to-energize customers impacted by upstream transmission line outages during PSPS events;
- Distribution Microgrids: Designated “main street” corridors where PG&E can safely provide electricity to central community resources (e.g., grocery stores, gas stations) by rapidly isolating them from the wider grid and re-energizing them using TG and a pre-installed interconnection hub (PIH);
- Back-Up Power Support (BUPS): Pre-staged or in-event deployment of TG, either behind or in front of the customer meter, to energize individual customer facilities where the absence or failure of existing back-up power could impact public safety; and
- Community Resource Centers (CRCs): “Hardened” pre-existing indoor facilities powered by TG with the objective of providing customers impacted by PSPS events a climate-controlled environment, device charging, and refreshments. The indoor CRC’s include an auto transfer switch and do not require resources to put the units on line.

PSPS Programs is a mitigation for wildfire risk. Consistent with PSPS Events, PSPS Programs directly mitigates wildfire risk by having the tools, personnel, and equipment in place to proactively de-energize a portion of PG&E’s 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 PG&E's above-ground power lines, suggesting a heightened risk of catastrophic wildfire.

b. Forecast

Table 6-6 below shows the recorded and forecast amounts for PSPS Programs.

TABLE 6-6
PSPS PROGRAMS (MWCS AB, WF, IG)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	AB6	PSPS Team Support	$336	$3,272	$6,599	$670	$11	–	–	–
2	WFN	PSPS Program Cost	9,469	6,782	8,425	6,413	10,015	$9,809	$9,352	$8,944
3	IG#	Temporary Generation	–	155	314	1,130	1,184	12,763	11,379	10,143
4		Total	$9,805	$10,209	$15,339	$8,213	$11,210	$22,572	$20,730	$20,616

Risk Mitigation for Wildfire Risk

	MWC	Risk Program ID	Risk Program Name	CBR
5	WF	WLDFR-M001	PSPS	25.3
6	IG#	WLDFR-M006	Temporary Generation	5.7

PSPS Project and Program Team forecasts were developed based on 2024 recorded costs. PG&E uses 2024 recorded costs because it represents PG&E's expected project and team needs in the future.[6]

The Temporary Generation Program forecast is based on 3-year historical recorded costs (2022-2024) to pre-stage with temporary generation based on historical impacted distribution microgrids, customer resource centers (CRC) and other critical facilities.[7]

3. Sectionalization (Capital MWC 3U)

a. Overview

The installation of remote-operated SCADA sectionalizing devices on PG&E's distribution system can support our ability to segment the distribution circuits near HFRA boundaries to reduce the impact and scope of PSPS events. PG&E plans to continue enhancing our distribution segmentation strategy to minimize the number of customers impacted during future PSPS events by refining which areas of a circuit to de-energize.

Distribution sectionalizing device installations have been focused on all circuits that traverse HFRA areas. When wildfire season concludes each year, PG&E integrates lessons learned from actual PSPS events and from historical weather modeling so that we can become more precise on which circuits to de-energize during a PSPS event to minimize customer impact and outage duration. With this data and feedback, PG&E can continue to install new SCADA automated sectionalizing devices closer to the refined meteorological shutoff boundaries and learn what areas of the community to analyze for even further granular sectionalizing.

Sectionalization is a mitigation for wildfire risk. These automated distribution sectionalizing devices enable PG&E to remotely de-energize lines as part of the PSPS program and reduce ignition risk during high wildfire risk weather.

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6 Exhibit (PG&E-4), WP 6-4, line 13.

7 Exhibit (PG&E-4), WP 6-4, line 15.

b. Forecast

Table 6-7 below shows the recorded and forecast amounts for Sectionalization.

TABLE 6-7
SECTIONALIZATION (MWC 3U)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	3UA	Pre-Installed Interconnection Hubs Microgrids	$9,573	$13,578	$4,812	$225	$652	–	–	–	–	–	–
2	3UC	MSO Replacements	13	406	1,036	1,839	2,992	–	–	–	–	–	–
3	3UP	Dist Protective Device	69,943	29,415	18,644	11,990	3,386	$5,168	$4,196	$2,096	$2,130	$2,008	$1,826
4		Total	$79,529	$43,399	$24,492	$14,054	$7,030	$5,168	$4,196	$2,096	$2,130	$2,008	$1,826

Risk Mitigation for Wildfire Risk

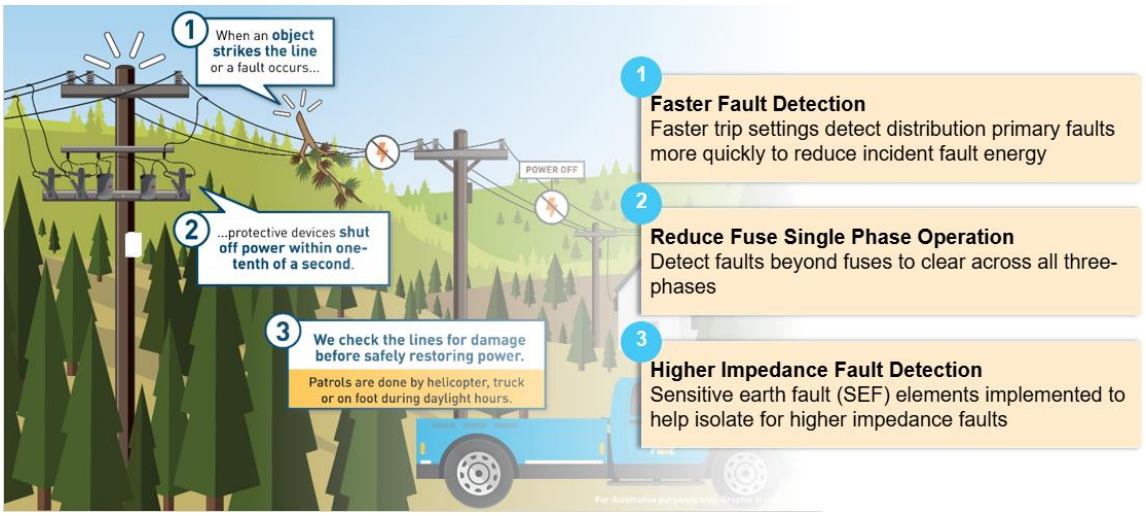
	MAT	Risk Program ID	Risk Program Name	CBR
5	3UP	WLDFR-M011	PSPS Granular Sectionalizing	Step 3 Exempt

Forecasts for Sectionalizing Devices in MWC 3UP were developed based on the 2025 workplan of 40 units and historical unit costs of $128 thousand. The $128 thousand unit cost is based on 2024 completed cost per unit.[8] PG&E's 2027 forecast is a decrease from 2024 recorded because PG&E plans to install fewer units in 2027.

C. Enhanced Powerline Safety Setting (EPSS) Forecast [Eric Lamoureux]

The purpose of the EPSS program is to reduce wildfire risk by minimizing the probability of an ignition event when a fault occurs on an electric distribution line and on select transmission lines in high fire risk areas during periods of elevated fuels and weather-related wildfire risk. EPSS achieves this by increasing the sensitivity and speed of system protective devices on circuits in High Fire Threat District (HFTD), High Fire Risk Area (HFRA) and non-tiered, EPSS buffer areas (or select circuits adjacent to HFRA areas), so that if an object contacts a distribution or select transmission line, power is automatically tripped within one-tenth of a second, reducing the potential for an ignition. EPSS is part of an integrated wildfire risk mitigation solution that will protect against hazards on powerlines that could start an ignition. Figure 6-3 below shows how EPSS works:

FIGURE 6-3
EPSS OVERVIEW



8 Exhibit (PG&E-4), WP 6-48 and 6-50.

The EPSS program includes multiple activities to execute, improve, and inform. These activities are discussed in detail in the following forecast sections.

1. Control Center Work and Automation (Expense MATs BAF, BAH; Capital MAT 63C)

a. Overview

When conditions are present that pose a wildfire risk, Distribution Control Center Operators (Operators) are responsible for enabling EPSS mode on devices and monitoring the system for outages. Operators receive daily instructions to enable and/or disable EPSS via a playbook from the EPSS Program Management Office (PMO) email based on the forecasted wildfire risk for the day. Operators navigate to the instructions for the devices on the impacted circuits and perform switching as directed. This process can occur multiple times a day, based on the forecasted meteorological risk and whether criteria for enablement is met. This work can result in operations to enable hundreds of devices at a time. In 2024, this work resulted in more than 32,000 individual actions to enable or disable EPSS settings.

In addition to enabling EPSS settings, the Operators are responsible for monitoring outages when EPSS settings are activated and coordinating with field personnel and engineering on the safe patrol and restoration of circuits. Operators also write, check, and direct switching related to EPSS outages. This work is captured in MAT BAF. Lastly, Operators review and adjust EPSS setting sensitivity as determined by engineers. This work is captured in MAT BAH.

Control Center work is a mitigation for wildfire risk. Control Center work mitigates wildfire risk by directly enabling the EPSS settings in locations where there is an increased probability of ignition risks.

b. Forecast

Tables 6-8 and 6-9 below show the recorded and forecast amounts for Control Center Work and Automation.

TABLE 6-8
CONTROL CENTER WORK (MATS BAF, BAH)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	BAF	Switching Activities	–	$2,998	$111	$792	$1,226	$4,816	$4,293	$4,293
2	BAH	Settings Activities	–	–	598	348	324	595	530	$530
3		Total	–	$2,998	$709	$1,140	$1,549	$5,410	$4,823	$4,823

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
4			
5	WLDFR-M020	EPSS	33.8

TABLE 6-9
CONTROL CENTER AUTOMATION (MAT 63C)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	63C	Control Center Automation	–	–	–	$1,680	$1,971	–	–	–	–	–	–

The 2027 forecast for Control Center Work is based on the highly variable nature of the EPSS protection strategy, which is influenced by changing climatological risk and the need to continue to expand EPSS capability appropriately to address risk. In 2024, there was a 64 percent increase in Control Center Work, driven by the most significant wildfire risk in the short history of the program as well as advancements in the meteorological models that drive daily EPSS enablement requirements. Given the unpredictability of long-term climatological forecasts and the continued evolution of this most effective wildfire mitigation, PG&E finds it appropriate to maintain prior long-term forecasts to support Control Center work on higher switching volumes, as well as an on-going multi-year process change to automate the EPSS enablement playbook. While processes are being developed, operators may be asked to support parallel process development and testing, until the new process is complete and implemented.[9]

2. Engineering Settings, Field Installation, and SCADA Testing (Expense MATs FZA, FZE, HGD)

a. Overview

PG&E conducts annual engineering protection review for all circuits to determine if changes to device settings or configurations are needed to optimize system performance. Additionally, distribution engineers evaluate and develop optimized settings for EPSS devices if conditions change or if new technologies are introduced and testing is needed. Once protection assessment and testing are complete, engineering will establish protective device settings and coordinate with Control Center personnel on the programming of protective devices. In addition, when a fault occurs on an EPSS-enabled circuit, the engineering team will run fault location analysis to identify the likely fault location to facilitate restoration. Engineering support and programming activities related to EPSS are tracked in MAT FZA. After coordinating the necessary settings changes with the control center, the settings template is sent to the local distribution line technicians for programming, SCADA testing,

[9] See Exhibit (PG&E-4), WP 6-6, line 1 and WP 6-47 line 19.

and installation into the devices in the field. The field work related to EPSS is tracked in MAT FZE. SCADA testing was captured in MAT HGD previously and is now combined under MAT FZE.

Engineering Settings, Field Installation, and SCADA Testing is a mitigation for wildfire risk. Wildfire ignition risk is reduced with the adjustment of the settings on protective devices to automatically turn off the power more quickly if it detects a distribution fault on the line.

b. Forecast

Table 6-10 below shows the recorded and forecast amounts for Engineering Settings, Field Installation, and SCADA Testing.

TABLE 6-10
ENGINEERING SETTINGS, FIELD INSTALLATIONAS, AND SCADA TESTING (MATS FZA, FZE, HGD)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	FZA	Engineering Settings	–	$1,396	$4,512	$2,227	$2,847	$3,754	$3,347	$2,983
2	FZE	Field Install	–	651	8,476	2,618	2,292	5,810	5,180	4,617
3	HGD	SCADA Test	–	–	3,393	83	174	–	–	–
4		Total	–	$2,046	$16,380	$4,927	$5,312	$9,564	$8,526	$7,601

Risk Mitigation for Wildfire Risk

5	MAT	Risk Program ID	Risk Program Name	CBR
6	FZA, FZE	WLDFR-M020	EPSS	33.8

The 2027 forecast for engineering and field support in MATs FZA and FZE are based on 2024 recorded and adjusted for expected program funding demand. The 2027 increase is driven by higher volume of EPSS and Down Conductor Detector settings updates and installs. This includes a new version firmware upgrade and Sensitive Ground Fault (SGF) threshold adjustment and install in approximately 2,500 devices beginning in 2025 and ramping down 11 percent year over year.[10]

3. Outage Response and Support (Expense MATs BFJ, BHE, DD#, IG#; Capital MAT 05#)

a. Overview

When outages occur on EPSS enabled circuits, the entire circuit downstream from the EPSS-enabled device that operated in response to the fault must be patrolled, including fuses. A patrol involves a visual examination of applicable overhead facilities to identify obvious structural problems and hazards that may have caused the outage. This work is tracked in MAT BHE. Prior to performing field work on an outage, work is first scheduled and dispatched to the respective locations. The scheduling and dispatching of work are captured in MAT DD#.

Post-outage patrols on EPSS-enabled circuits ensure the system is safe to facilitate restoration of the outage as quickly as possible. This requires the deployment of ground and/or helicopter assets to provide a full patrol and investigation of the protective zone(s) that experienced the outage. Troubleshooters perform the bulk of these patrols, and PG&E currently maintains sixteen standby helicopters ready to be deployed in the event of an EPSS outage to support a troubleshooter's patrols. The number of outages and size of the zones to be patrolled will drive the specific resource requirements for personnel and air assets.

In order to determine the cause of outages that are not obvious on the initial patrol and restoration following an EPSS outage, PG&E

10 Exhibit (PG&E-4), WP 6-6, line 5 and line 7.

leverages drones to perform visual examination of applicable overhead facilities to identify obvious structural problems and hazards that may have caused the outage and was not discernable during the initial ground or helicopter patrol. Helicopter standby costs and drone patrols are captured in MAT IG#.

Outage Response and Support is a mitigation for wildfire risk. As outages occur, patrol and outage response is critical to quickly ascertain the cause of outage and take appropriate action to mitigate problems and hazards that potentially can lead to additional wildfire risk. Power is restored only after conditions are determined to be safe. PG&E maintains an abundance of caution approach as mitigating ignition risk, minimizing customer outages, and timely outage restoration are key pillars for EPSS.

b. Forecast

Tables 6-11 and 6-12 below show the recorded and forecast amounts for Outage Response, Dispatch, Other Patrol and Support, Helicopter/Drone Standby, and Patrol Equipment.

TABLE 6-11
OUTAGE RESPONSE, DISPATCH, OTHER PATROL AND SUPPORT, HELICOPTER/DRONE STANDY, AND PATROL EQUIPMENT (MATS BFJ, BHE, DD# AND IG#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	BFJ	Other Patrol & Support	–	–	$868	$51	$48	–	–	–
2	BHE	Outage Response	–	–	12,877	10,277	10,771	$13,885	$13,885	$13,885
3	DD#	Dispatch	–	–	610	258	148	722	643	643
4	IG#	Helicopter/Drone Standby	–	–	17,978	16,787	13,545	20,456	20,020	17,847
5	IG#	Other Patrol & Support (MWC IG)	–	–	534	232	90	–	–	–
6		Total	–	$12,658	$31,999	$27,554	$24,555	$35,062	$34,548	$32,375

Risk Mitigation for Wildfire Risk

7	Risk Program ID	Risk Program Name	CBR
8	WLDFR-M020	EPSS	33.8

TABLE 6-12
OUTAGE RESPONSE, PATROL AND DISPATCH (MAT 05#)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	05#	Patrol Equipment	–	–	–	$90	$190	–	–	–	–	–	–

PG&E's 2027 forecast for MATs BHE is based on a three-year historical average cost for post-outage patrols on EPSS enabled circuits and adjusted in anticipation of a greater number of circuit miles enabled, a longer enablement season, and continued support for increasing outages, as experienced in 2024 (approximately 20 percent more EPSS outages experienced in 2024 than 2022-2023 historical average).[11] Applying a three-year average is appropriate to account for and smooth out weather patterns and seasonal variation and anomalies, dating back to the start of the program. PG&E anticipates more frequent and severe wind events, periods of extreme precipitation, and intense hot/dry conditions to significantly increase wildfire and reliability risks, thus increasing the need for PG&E to be sufficiently prepared for responding to extreme and changing conditions.

4. EPSS Program Management Office (PMO) (Expense MAT IG#)

a. Overview

In 2022, PG&E established the Program Management Office (PMO) (MAT IG#) to oversee activities related to planning, operation, data, and governance activities associated with EPSS. The activities include but are not limited to: standing up program strategies; identifying resource and work planning activities; providing reliability studies of outages and ignitions; supporting regulatory and compliance commitments; developing data infrastructure, business analytics and daily reporting; establishing cross-functional relationships with execution and key partner stakeholders to ensure alignment and delivery of program goals; conducting daily outage reviews and implementing mitigation strategies; and developing and maintaining process, procedures and control measures for the program. Much of the initial work to stand up the program was performed by external consultants, EPSS PMO leadership, and matrixed team members.

Since 2022, the PMO has hired additional internal resources to expand aspects of program management, process improvement,

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[11] See Exhibit (PG&E-4), WP 6-6, lines 2, 3, 4, 13, 15. For MAT BHE see Exhibit (PG&E-4), WP 6-10. For MWC 05 see Exhibit (PG&E-4), WP 6-46, line 2.

operational expertise, business analytics and technical development for EPSS, and to reduce costs associated with work that had been previously outsourced.

EPSS PMO is a mitigation for wildfire risk. The EPSS PMO provides program oversight and direction for ensuring the continued success and effectiveness of reducing wildfire ignition risk. Additionally, the EPSS PMO continually explore opportunities to expand wildfire mitigation opportunities (i.e., supplement EPSS with DCD for high-impedance faults) and ensure all program activities and processes are maintained, improved and governed (i.e., periodic review of enablement criteria).

b. Forecast

Table 6-13 below shows the recorded and forecast amounts for the EPSS Program Management Office (PMO).

TABLE 6-13
EPSS PROGRAM MANAGEMENT OFFICE (PMO) (MAT IG#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	IG#	EPSS PMO	–	$3	$4,010	$5,562	$6,603	$4,020	$3,748	$3,505

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
2			
3	WLDFR-M020	EPSS	33.8

PG&E's forecast for EPSS PMO for 2027 is based on 2024 recorded costs as it is most reflective of work that will continue in the future.[12] The 2027 forecast decrease as compared to 2024 recorded is driven by the ramp down of contract related costs incurred in 2024 and prior years to stand up the program, as initial work performed by consultants are transitioned to internal resources over time. The cost savings and reduced spend in contract will be partially offset by increased internal labor needed to fully support and optimize steady-state program management activities.

5. Temporary Generation (TG) EPSS (Expense MAT IG#)

a. Overview

The Temporary Generation Program mitigates customer outages during EPSS events by utilizing procured temporary generation at safe to energize customer locations. Since EPSS program inception in 2021, the TG team has supported EPSS affected schools and hospitals by providing Back-up Power Support (BUPS) during EPSS outages. Typically, sites are pre-staged with temporary generation and automatic transfer switch, either behind or in front of the customer meter, to energize individual customer facilities where the absence or failure of existing back-up power could impact public safety. The program costs include equipment rental, labor, transportation, pre-staging costs, and regular wellness checks. Unlike PSPS events, in-event operating cost are included in the pre-staging forecast cost, allocated forecast cost include operating the temporary generators, i.e. fuel, labor, etc.

Temporary Generation is a mitigation for wildfire risk. By providing temporary generation during EPSS outages, safety risk is mitigated for eligible customers where back-up power is not available.

b. Forecast

Table 6-14 below shows the recorded and forecast amounts for the Temporary Generation Program.

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12 See Exhibit (PG&E-4), WP 6-6, lines 16.

TABLE 6-14
TEMPORARY GENERATION - EPSS (MAT IG#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	IG#	Temporary Generation – EPSS	–	$7	$847	$932	$1,282	$1,924	$1,715	$1,529

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
2			
3	WLDFR-M006	Temporary Generation (EPSS)	5.7

The Temporary Generation – EPSS Program 2027 forecast is based on three-year (2022-2024) historical baseline cost and trend to pre-stage schools and hospitals with temporary generation during EPSS outages and adjusted for expected increased support for schools and hospitals during EPSS outages.[13]

6. Customer Support Programs (Expense MAT IG#)

a. Overview

Communication to customers of the importance of wildfire safety programs is critical to the success of programs like EPSS. With an increase in the number of EPSS outages experienced in 2024, outreach and education continue to play a critical role in providing awareness to customers and communities of the impacts of wildfires and the importance of having multiple layers of protection like EPSS to help reduce wildfire risk. Customer outreach and education can be divided into two categories – proactive and reactive.

Proactively, PG&E annually completes several pre and post season outreach and education initiatives for customers served by circuits protected by EPSS. These initiatives include virtual and in-person engagements, collateral creation, and direct-to-customer communications. PG&E also has quarterly meetings with the CPUC to provide operational updates, customer communications, and resilience program participation. In addition, PG&E conducts annual outreach to all customers in areas more likely to be impacted by EPSS to create wildfire awareness, gather contact information, and provide wildfire program updates.

Reactively, PG&E has improved the EPSS outage communications tools to include SMS, email, and social capabilities. This communications improvement provides customers with enhanced visibility of their outage, cause (if known), and follow-up communications as more information is available. The tool also allows for PG&E to monitor EPSS outage count by individual customers to identify potential escalations proactively and implement enhanced engagement

[13] See Exhibit (PG&E-4), WP 6-6, line 11.

(Interactive Voice Response (IVR), webinar, in-person event) in those communities.

The Customer Outreach & Education team annually evaluates how to improve communications and the overall customer experience. PG&E plans to provide additional visibility on PG&E's Progress Map to EPSS operational improvements – including but not limited to animal guards, firmware updates, and sectionalizing equipment. PG&E also plans to continue to enhance the features and capabilities of the outage communication tool and enhanced engagement offerings to continue to deliver an improved customer experience.

Prior to and during EPSS outages, the Marketing & Communications team will enhance PG&E's communications to all potentially impacted customers, through the following activities:

- Increasing communications to impacted customers, including via email and direct mail;
- Increasing social media and local media outreach efforts to grow awareness, including posts on Nextdoor and Facebook; and
- Using paid advertising on local radio and social feeds.

These initiatives may be modified and additional initiatives added as the program progresses.

Customer Support program is a mitigation for wildfire risk. Customer outreach and education is critical to providing awareness to customers and communities of the impacts of wildfires and the importance of having multiple layers of protection like EPSS to help reduce wildfire risk. PG&E communication prior to, during, and post EPSS outage is vital to bring situational awareness for impacted customers.

b. Forecast

Table 6-15 below shows the recorded and forecast amounts for EPSS Customer Support.

TABLE 6-15
CUSTOMER SUPPORT PROGRAMS (MAT IG#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	IG#	Customer Support Programs	–	$492	$14,321	$7,789	$8,169	$9,205	$9,013	$9,245

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
2			
3	WLDFR-M020	EPSS	33.8

PG&E's forecast for Customer Support programs is based on 2024 recorded costs plus planned improvements to PG&E's Progress Map, outage communication tool and enhanced engagement.[14] PG&E used 2024 as a baseline for forecasting given that the EPSS program's customer strategy was the most mature in 2024. That maturity, coupled with the significantly escalated EPSS activity that was seen, established 2024 as an appropriate year to baseline for future forecasting.

7. Down Conductor Detection (DCD) (Capital MAT 3US)

a. Overview

While EPSS is effective in mitigating high current faults, approximately 50 percent of High Fire Threat District (HFTD) Reportable Fire Ignitions that occurred on circuits with EPSS enabled resulted from low-current, high-impedance faults. To add protection for fault types not yet fully mitigated through EPSS, Down Conductor Detection (DCD) was added in 2022 to supplement and provide enhanced ground fault protection to address low-current, high-impedance faults. DCD technology can improve the ability to detect and isolate high impedance faults before an ignition can occur. DCD uses sophisticated harmonic analysis to detect arcing present during high impedance faults and provides an immediate trip response. The engineering and programming of existing equipment capable of DCD and the installation of new equipment with DCD functionality helps to address high impedance fault conditions within the HFRA and EPSS buffer areas. Through 2024, over 1,900 devices have DCD capability, covering more than 19,000 HFRA miles.

Down Conductor Detection (DCD) is a mitigation for wildfire risk as it mitigates ignition risk by quickly turning off power when a high-impedance fault occurs on the line.

b. Forecast

Table 6-16 below shows the recorded and forecast amounts for the Downed Conductor Program.

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14 See Exhibit (PG&E-4), WP 6-6, line 12.

TABLE 6-16
DOWN CONDUCTOR DETECTION (MAT 3US)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted					Forecast					
			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	3US	Down Conductor Detection	–	–	$1,112	$12,743	$12,937	$10,793	$10,506	$10,253	$10,902	$9,874	$8,158

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
2			
3	WLDFR-M020	EPSS	33.8

The 2027 forecast for Down Conductor Detection (DCD) is based on 2024 recorded costs and assumes lower units to be completed in 2027.[15] In 2024, DCD was installed in over 400 devices under this program. PG&E plans to install DCD in approximately 200 devices annually in 2027-2030. Through 2024, DCD technology was only available for 3-wire system by retrofitting existing controllers. Beginning in 2025, DCD technology is expanding to include 4-wire system through controller replacements and in some cases, full line recloser replacements, resulting in a higher unit cost per install.

8. Substation and Support Programs (Expense MATs GC2, HXA; Capital MATs 09B, 48D)

a. Overview

The Substation Relay Replacement program (MAT 09B) will be replacing or retrofitting relays at various substations to provide Down Conductor Detection (DCD) capability for high-impedance fault detection. However, in some cases, some substation circuit breakers with older protective relays cannot be enabled with EPSS and DCD capability until those relays are replaced with modern IPAC cabinets. The Circuit Breaker (CB) replacement program (MAT 48D) identifies old and problem circuit breakers within the system which needs to be replaced so that EPSS and DCD capability can be added to the relays to protect the circuit breaker zones.

EPSS support work at substations includes two expense programs. The Substation Support program (MAT GC2) covers operational maintenance for newly installed and existing equipment. The Substation Automation program (MAT HXA) covers automation engineering and relay settings needed for new technology as well as adjusting and programming settings on existing equipment.

Substation and Support Programs are a mitigation for wildfire risk as they mitigate ignition risk by quickly turning off power when a fault occurs on the line.

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15 See Exhibit (PG&E-4), WP 6-51.

b. Forecast

Tables 6-17 and 6-18 below show the recorded and forecast amounts for the Substation Relay Replacement & Circuit Breaker (CB) Replacement, Substation Support and Substation Automation programs.

TABLE 6-17
SUBSTATION SUPPORT AND SUBSTATION AUTOMATION (MATS GC2, HXA)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	GC2	Substation Support	–	$437	$3,993	$211	$55	$192	$192	$153
2	HXA	Substation Automation	–	–	1,473	73	57	289	257	229
3		Total	–	$437	$5,466	$283	$112	$481	$450	$382

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
4			
5	WLDFR-M020	EPSS	33.8

TABLE 6-18
SUBSTATION RELAY REPLACEMENT AND CIRCUIT BREAKER REPLACEMENT (MATS 09B, 48D)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	09B	Substation Relay Replacement	–	$2,742	$12,183	$13,887	$18,792	$20,466	$17,295	$17,278	$17,556	$16,552	$15,057
2	48D	Circuit Breaker Replacement	–	–	990	4,530	5,498	4,007	5,298	9,155	3,000	3,000	3,000
3		Total	–	$2,742	$13,174	$18,417	$24,290	$24,473	$22,593	$26,434	$20,556	$19,552	$18,057

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
4			
5	WLDFR-M020	EPSS	33.8

The 2027 forecast for Substation support with engineering settings adjustment, maintenance, and testing (MATs GC2 and HXA) is based on 2024 baseline budget and adjusted for anticipated firmware upgrades, engineering setting revisions, and relay maintenance and testing needed as additional relays and circuit breakers will have EPSS and DCD protection.[16]

The 2027 forecasts for the Substation Relay and Circuit Breaker replacement programs (MATs 09B and 48D) are consistent with 2024 recorded costs and program funding allocation.[17] In 2024, DCD was installed in more than 40 relays with 9 circuit breakers replaced. PG&E likewise plans to install DCD in approximately 40 relays annually through 2027 and ramping down into 2030 as more units and high fire risk areas will have been covered. Many of the circuit breaker and relay replacement programs are multi-year projects that are forecasted in phases.

9. EPSS Reliability Programs and Vegetation Management (Expense MATs IG#; Capital MATs 49B, 49D, 49E, 49G)

a. Overview

Installing distribution protective devices provides enhanced capability to mitigate ignition risk, as well as improve reliability and reduce customer outage impacts on EPSS circuits. Devices that enable PG&E to sectionalize the grid both reduce the impacted circuitry and reduce the number of customers impacted by the outage event and enable PG&E to more quickly identify where faults occur to speed restoration efforts.

First, PG&E deploys microprocessor-based Supervisory Control and Data Acquisition (SCADA) operable line reclosers and switches, which provide the ability to remotely operate the overhead electric distribution system. The microprocessor-based controls provide greater SCADA reliability and operational flexibility and functionality because they improve PG&E's ability to isolate faults and re-energize circuits in the

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16 See Exhibit (PG&E-4), WP 6-6, lines 6 and 8.

17 See Exhibit (PG&E-4), WP 6-46, lines 10 and 13.

event of an outage. Legacy controller changeout with SCADA microprocessor controls is captured in MAT 49B.

Second, PG&E continues enhancing our distribution segmentation strategy to minimize the number of customers impacted during EPSS outages by installing more reclosers and fuse savers within the HFRA and EPSS buffer areas (MAT 49D). PG&E will replace certain fuse protective zones with line reclosers and fuse savers to provide the same ignition reduction benefits, but with fewer customers impacted if an outage occurs on the downstream sections. Installations of protective devices for ignition and reliability benefit were previously recorded in MAT 49X.

Third, PG&E will continue to install fault indicators (FI), which enable PG&E to more quickly identify fault direction and reduce patrol times and EPSS outage durations. The FIs are used to help identify unknown outages. The technology works to pinpoint potential trouble areas to assist engineering and field workers identify solutions to address unknown caused outages. Since inception, PG&E proactively installed over 4,000 FIs on EPSS circuits. This proactive FI project was completed in 2024 and provides extensive coverage on EPSS circuits. Starting in 2025, PG&E will install FIs based on the outage review process and field findings. Fault indicator work is currently captured in MAT 49G and previously captured in MAT 49X.

Finally, PG&E looks for cost savings in this program by evaluating opportunities to bundle work in the EPSS footprint. For instance, PG&E continues to evaluate reliability performance on circuits with historically poor reliability and recurring outages, to identify bundling mitigation opportunities to improve overall circuit performance. Mitigation strategies can include adding multiple sectionalizing devices to segment the circuit and reduce customer impacts in the event of an EPSS outage. Other bundling strategies can include adding animal guard, pole replacement, vegetation trimming, or hardening and protecting critical operating equipment. The forecast is based on circuit bundling needs and opportunities and is captured in MAT 49E.

EPSS Reliability Programs and Vegetation Management are mitigations for wildfire risk as work bundling, upgrading and adding protective devices, and managing vegetation will improve systems reliability and mitigate wildfire risks and reduce outage impacts to customers.

b. Forecast

Table 6-19 below shows the recorded and forecast amounts for Vegetation Management. Table 6-20 shows the recorded and forecast amounts for SCADA Install, EPSS Reliability, Fault Indicator, and Circuit Bundling.

TABLE 6-19
EPSS RELIABILITY PROGRAMS AND VEGETATION MANAGEMENT (MAT IG#)
SUMMARY OF EXPENSE

(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	IG#	Vegetation Management	–	–	$9,190	$21	$95	–	–	–
			Risk Mitigation for Wildfire Risk							
2		Risk Program ID			Risk Program Name				CBR	
3		WLDFR-M020			EPSS				33.8	

TABLE 6-20
EPSS RELIABILITY PROGRAMS AND VEGETATION MANAGMENT (MATS 49B, 49D, 49E, 49G)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	49B	SCADA Install	–	–	$137	$1	$ 2,322	$935	$790	$789	$802	$756	$688
2	49D	EPSS Reliability	–	–	–	–	–	13,791	12,749	12,057	16,172	14,758	19,329
3	49E	Circuit Bundling	–	–	–	6	224	1,803	1,495	1,493	1,517	1,430	1,301
4	49G	Fault Indicator	–	–	–	–	–	1,683	1,422	1,420	1,443	1,361	1,238
5	49X	EPSS Reliability	–	–	3,613	6,533	10,548	–	–	–	–	–	–
6		Total	–	–	$3,750	$6,541	$13,095	$18,211	$16,455	$15,760	$19,934	$18,305	$22,556
			Risk Mitigation for Wildfire Risk										
		Risk Program ID	Risk Program Name					CBR					
7		WLDFR-M020	EPSS					33.8					

The 2027 forecast for EPSS reliability programs is based on 2024 recorded costs as it best reflects the work that is needed to mitigate current reliability impacts due to weather conditions.[18] California's climate of frequent, dry and severe weather conditions is predicted to continue, thereby adversely impacting PG&E's wildfire and reliability risks. As previously mentioned, EPSS experienced approximately 20 percent more outages in 2024 than 2022-2023 historical average. PG&E anticipates similar meteorological weather patterns and intense hot/dry conditions to continue. The 20 percent increase in the 2027 program forecast from 2024 recorded costs is consistent with the outage growth rate and is needed to improve reliability on poor performing circuits through targeted and bundling opportunities on specific and impacted feeder locations to provide resiliency against growing risks. Furthermore, PG&E will continue to proactively advance and improve general reliability and reduce customer outage footprint by adding more sectionalization and fault indicating devices or replacement of equipment.

10. Emergent Technology & Gridscope (Expense MAT IG#; Capital MAT 21#)

a. Overview

Annually, the EPSS PMO evaluates and identifies emerging technology to improve reliability and reduce ignition risk. EPSS incorporated new and innovative solutions in 2023 like Gridware's Gridscope technology, which uses sensors and real-time monitoring to enhance grid reliability and safety, alongside other advanced technologies to supplement existing wildfire mitigation strategies. Gridscope devices are state-of-the-art sensory devices that collect asset performance data that can be used in real-time to manage outages, as well as for work planning for future reliability programs. Gridscope devices are mounted on poles and can be installed within minutes and are operational within 48 hours. The technology is self-powered and

[18] See Exhibit (PG&E-4), WP 6-6, line 14. See also Exhibit (PG&E-4), WP 6-46, lines 15-18.

remains operational during outages to collect data used to support response, restoration, and post-event reviews. Gridscope's intelligent sensor monitors vibration, acoustics, visible light, and more, then process the information to detect faults and other hazards not readily identifiable via existing PG&E devices. Upon successful completion of the pilot program (MAT IG#), Gridscope was subsequently capitalized under MAT 21#.

The benefits of Gridscope include: (1) potential reduction of the proportion of Unknown-Cause Outages, (2) reducing duration of outages and improving safety for our crews and customers by directing restoration resources to precise fault locations, (3) identifying previously unidentified hazards that could lead to an ignition. The technology contains a variety of sensors that allow for discovery and determination of fault types, pole tampering, climate changes, other outage causes, and potential hazards that have not resulted in an outage. Through 2024, PG&E installed over 10,000 Gridscope devices throughout its service territory. PG&E will continue to install devices in HFRA and EPSS buffer zone and other critical areas in future years.

Emergent Technology & Gridscope is a mitigation for wildfire risk as the technology provides more precise fault locations for faster outage restoration as well as help identify previously unidentified hazards that could lead to an ignition.

b. Forecast

Tables 6-21 and 6-22 below show the recorded and forecast amounts for Emergent Technology & Gridscope.

TABLE 6-21
EMERGENT TECHNOLOGY (MAT IG#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	IG#	Emergent Technology	–	–	$197	$2,320	$9,338	$505	$450	$401

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M020	EPSS	33.8

TABLE 6-22
EMERGENT TECHNOLOGY (MAT 21#)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	21#	Gridscope	–	–	–	–	$2,007	$2,530	$2,138	$2,136	$2,170	$2,046	$1,862

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M020	EPSS	33.8

PG&E's 2027 forecast for emerging technologies in MAT IG# is based on 2024 baseline program allocation of approximately $400,000 annually for costs associated with research, analysis, testing, project set-up, and pilot program management. 2024 recorded cost for IG includes costs associated with the concerted effort of installing 10,000 Gridscope devices across PG&E's service territory in high-fire risk areas, an expense that will not continue past 2024. Beginning 2024, Gridscope costs are capitalized as the program is no longer a pilot. The 2027 forecast for Gridscope in MAT 21# is based on 2024 baseline program targeted funding allocated for the program.[19]

D. Customer Battery Programs Forecast [Vitaly Tyurin]

PG&E offers a portfolio of battery programs to customers who are impacted by wildfire safety outages. These programs are a demand-driven activity: PG&E markets the programs to eligible customers and the final number of customers served is a function of how many customers are both interested in and able to participate based on program rules and capacity. The customer battery programs initially focused on addressing the critical needs observed for customers with medical devices after the first PSPS events in late 2018. As the EPSS program has scaled up, the battery programs have expanded to include permanent battery backup systems, as discussed in PG&E's 2023 GRC Application[20] and subsequent Wildfire Mitigation Plan.[21] Each program in PG&E's current portfolio is customized to focus on different permutation of battery type (portable versus permanent) and customer type (general market customers versus those with unique needs such as low-income or medical baseline). Rebate programs typically target general market customers, while the more hands-on direct install programs, where a PG&E contractor works directly

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19 See Exhibit (PG&E-4), WP 6-6, line 10 and WP 6-46, line 5.

20 A.21-06-021, February 25, 2022 Supplemental Testimony, Exhibit (PG&E-4), Ch. 4.6, p. 4.6-18 includes a description of the "fixed power solutions" pilot.

21 PG&E 2023-2025 Wildfire Mitigation Plan, Rev. 7 (Dec. 5, 2024), OEIS Docket #2023-2025-WMPs, description of battery programs and objective PS-05, evaluating the transition to permanent battery solutions in multiple locations, available at: <https://www.pge.com/en/outages-and-safety/safety/community-wildfire-safety-program.html#> (accessed April 3, 2025).

with a customer to deliver and install equipment on the customer's premise, target customers with more unique needs.

PG&E's customer battery programs are highly successful in mitigating outages: in 2024, over 9,700 customers who were impacted by PSPS or EPSS outages participated in a customer battery program, and more than 85 percent of participants with a subsequent outage reported that their needs were met due to the program. Further, many participants report that PG&E's programs were instrumental in their decision or ability to adopt battery storage.

Participants are the primary beneficiary of the customer battery programs in that the programs lower barriers to battery adoption, especially for customers with unique needs or in remote locations, enabling them to withstand repeated wildfire safety outages. All customers are secondary beneficiaries in that mitigating PSPS and EPSS outages, especially for highly-impacted customers, is integral to the long-term support for wildfire safety-driven outages and the associated wildfire risk reduction.

In this 2027 GRC, PG&E proposes to improve its wildfire-focused Customer Battery Program portfolio. First, PG&E will expand its more recent, rebate-based programs to enable more customers to participate while keeping costs low. Second, PG&E will shift its residential permanent battery direct-install program to a capital battery program in which PG&E would own and operate batteries on customer premises. This change will lower program costs and enable PG&E to realize additional grid benefits.

The plan to transition some battery programs from expense to capital programs, increase the size of the most cost-effective expense programs, and expand certain permanent battery programs, results in very different cost forecasts for each battery program in the attrition years (2028-2030) than the Test-Year of 2027. As a result, PG&E requests specific post Test-Year adjustments for customer battery programs in this chapter to capture the dynamics of the program portfolio. This differs from the simple escalation approach described in Exhibit (PG&E-11).[22] Accordingly, all customer battery programs are presented in their full detail, including attrition years.

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22 Attrition adjustment policies and mechanics, including discrete expense and capital programs, are addressed in Exhibit (PG&E-11), Ch. 1, 2 and 3.

PG&E's battery program forecast anticipates serving an additional 50 thousand customers across all forecast years and all programs. The greatest growth is forecasted for PG&E's newer rebate programs and targeted permanent battery installations, which would see a tripling of program penetration among eligible customers.

The customer battery programs presented here are distinct from, but complementary to, the Self Generation Incentive Program (SGIP), PG&E's Backup Power Transfer Meter program described in Exhibit (PG&E-6), Chapter 7, and PG&E's 2025 non-HFTD customer battery program funded using Volumetric Performance Fees (VPF) from extended operation of the Diablo Canyon Power Plant.[23] As PG&E's battery programs operate in a dynamic environment where technology, prices and outage mitigation needs are constantly changing, PG&E's programs will continue to evolve, incorporating new resiliency solutions and addressing the changing needs of customers.

The Customer Battery Programs proposed below are mitigations for wildfire Risk with PSPS and EPSS and Failure of Distribution Overhead Assets. Customer Battery Programs mitigate wildfire risk because they enable PG&E to implement wildfire-risk-reducing outages through the PSPS and EPSS by keeping critical customer loads energized during some or all of those outages. This outage mitigation therefore produces its own quantifiable risk reduction. In addition, the batteries also mitigate outages not caused by PSPS or EPSS and therefore provide additional reliability benefits. This is indicated by the inclusion of Distribution Overhead risk reduction, contributing to the CBR scores presented in the forecast tables below.

1. Customer Battery Expense Programs (Expense MWC IG)

a. Overview

PG&E currently offers four types of expense battery programs:

- Portable Battery Direct Delivery Programs (PSPS CC Portable Battery Program & Center For Independent Living California Contract):[24] PG&E currently has two programs which directly

[23] D.24-12-033, p. 58.

[24] For increased clarity, PG&E includes in parentheses the names used in its tables and workpapers, which are consistent with its financial tracking systems.

deliver portable batteries to residential customers at no cost to them: the Portable Battery Program (PBP) and the Disability Disaster Access and Resources (DDAR) program which is run by the California Foundation for Independent Living Centers (CFILC). As these portable battery programs deliver a similar solution to similar customers, these programs are modeled for risk under the same Risk ID, called Portable Battery Programs in the summary table below. These programs are highly integrated with other wildfire mitigation operations and necessary to comply with the Commission's 2021 PSPS Decision (D.21-06-034). In that decision, the CPUC requires PG&E to offer programs to support resiliency for customers that rely on electricity to maintain necessary life functions.[25] While the CBR is less than one for these programs, as they provide a significant amount of support to customers with access and functional needs, offering this program is consistent with the directives of that decision.

The portable battery programs began in response to early PSPS events, and they both use third-party partners to assess customers' need to power essential devices during an outage and then deliver those portable batteries where appropriate. In 2024, PBP reached out to more than 6,000 customers and delivered 3,797 batteries while the CFILC's DDAR program, which also includes non-battery-related activity, reached out to more than 1,500 customers and delivered 580 batteries to customers. By December of 2024, more than half of portable battery recipients reported already experiencing an outage since participating, and 98 percent of those found the battery met their needs.

- Portable Battery Rebate (Generator Rebate Program): PG&E has the Generator and Battery Rebate Program (GBRP) where residential and commercial customers make a generator or battery purchase on their own and then receive a rebate. The GBRP has a separate Risk ID and is modeled separately from other portable

[25] D.21-06-034, p. 170, Ordering Paragraph (OP) 2 and p. A10.

battery programs for two reasons: this program supports portable generators in addition to portable batteries, and the rebate does not cover the whole cost of a portable battery or generator. These differences impact both the cost of the program as well as the number of outage minutes mitigated, two key inputs to the risk CBR analysis. In 2024 GBRP sent more than 2 million marketing messages, resulting in more than 3,500 rebates to customers. Of these customers, 86 percent reported experiencing an outage and using their generator or battery to meet their needs as of December 2024.

- Permanent Battery Direct Install Programs (EPSS - Customer Mitigation (FPS)): PG&E's primary direct install permanent battery program is the Residential Storage Initiative (RSI) program, which provides a full permanent battery system installation service to highly impacted residential customers at no cost to them. In 2024 the RSI program contacted more than 8,000 eligible customers, resulting in 1,449 permanent battery systems installed over the course of the year. As a new program, 2024 was the first year that PG&E was able to gather program survey data: 87 percent of respondents reported experiencing an outage since participation, including 25 percent who experienced five or more outages, and 91 percent found that the battery met their needs. PG&E's other Fixed Power Solutions program provides customized, direct outage mitigation support to K-12 schools and critical facilities. Together these programs constitute PG&E's "Fixed Power Solutions" (FPS) effort.
- Permanent Battery Rebates (EPSS- CC-Generator Rebate Program (PBSR)): PG&E also provides a permanent battery rebate program for residential customers, the Permanent Battery Storage Rebate (PBSR). Since PBSR is a partial rebate, it is given a separate risk ID from the RSI program. The PBSR is PG&E's newest customer battery program: in 2024 the PBSR program sent more than 200,000 marketing messages and delivered 301 permanent battery rebates to customers. By December 2024, 92 percent of those

customers reported using their permanent battery for both outage mitigation and lowering their bills.

Lastly, the battery expense programs include an expense forecast for support (PSPS Customer Resiliency NonEvent), which accounts for PG&E expenses on cross-cutting support of the battery program portfolio such as strategic planning, regulatory support, and reporting.

As described above, this portfolio of customer battery expense programs reduces the customer impact of PSPS and EPSS outages, thus enabling the sustainability of the PSPS and EPSS programs. Each Risk ID for the four types of expense battery programs described above is provided in the following summary table. The support forecast is treated as a foundational activity and is allocated to each of the four risk IDs in proportion to their forecast amounts.

b. Forecast

Table 6-23 below provides the recorded actuals and forecast for each battery expense program including the specific post Test-Year adjustments request for years 2028-2030.

TABLE 6-23
CUSTOMER BATTERY EXPENSE PROGRAMS (MWC IG)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Activity Description	Recorded Adjusted					Forecast					
		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	PSPS CC Portable Battery Program & Center For Independent Living California Contract (PBP/DDAR)	$18,273	$18,328	$24,287	$14,610	$12,635	$12,795	$9,000	$10,000	$8,000	$8,000	$8,000
2	Generator Rebate Program (GBRP)	148	1,092	820	224	1,442	1,350	5,350	5,350	5,350	5,350	5,350
3	EPSS – Customer Mitigation (FPS)	–	–	2,104	25,911	14,973	38,082	35,299	43,260	6,190	6,213	5,710
4	EPSS- CC-Generator Rebate Program (PBSR)	–	–	718	4,607	(755)	5,600	5,600	10,000	8,600	8,600	8,600
5	PSPS Customer Resiliency NonEvent	233	486	422	524	562	500	500	1,000	1,000	1,000	1,000
6	Total	$18,655	$19,905	$28,351	$45,876	$28,858	$58,327	$55,749	$69,610	$29,140	$29,163	$28,660

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
7	DOVHD-M031 WEPSS-M011 WPSPS-M003	Portable Battery (PBP and CFILC/DDAR)	0.4
8	WEPSS-M017, WPSPS-M008, DOVHD-M039	Generator and Battery Rebate Program (GBRP)	23.6
9	DOVHD-M033, WEPSS-M013, WPSPS-M005	RSI Battery	1.7
10	DOVHD-M032, WEPSS-M012, WPSPS-M004	Permanent Battery Rebate (PBSR)	4.2
11	DOVHD-M036, WEPSS-M014, WPSPS-M007	PSPS Customer Support	Foundational

The forecasts for each program were developed using a fixed plus unit-cost based forecast for each program. Fixed cost and program-specific unit descriptions are provided in the battery program Workpaper.[26] As these programs are demand-based, fixed costs largely consist of planning, marketing, contract management, data management, financial oversight and internal and external reporting. The unit forecasts are based on PG&E's proposed scale for each program and takes into consideration the anticipated end of funding for new participants in the predominant permanent battery incentive program for utility customers in California, the Self Generation Incentive Program (SGIP): funding for the current SGIP budget, which includes allocations specifically for customers in HFTD or otherwise impacted by wildfire safety outages, ends on January 1, 2026.[27] This will be replaced by a new, smaller SGIP budget to support solar and storage for low-income customers broadly, which PG&E anticipates to be exhausted before its end in June 2028.[28] The 2027 forecast increase as compared to 2024 recorded presented in detail above is primarily driven by the following trends:

- The portable battery direct delivery programs are forecasted to remain at a level similar to 2023 and 2024 after declining from the high levels seen in the earlier years of the PSPS program. As these mature programs have achieved substantial penetration (over 30%, based on 2024 data) among the target customer group, they are projected to remain at a decreased level;
- The portable battery rebate for general market customers is forecasted to increase from recorded actuals and remain steady through the GRC period at this higher level. As a broadly-available

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26 Exhibit (PG&E-4), WP 6-5.

27 Pub. Util Code § 379.6(a)(2) on SGIP funding states that "On January 1, 2026, the commission shall provide repayment of all unallocated funds collected pursuant to this section to reduce ratepayer costs."

28 D.24-03-071 at p. 8, "The [SGIP AB 209] funds are available for encumbrance or expenditure until June 30, 2026, and must be liquidated by June 30, 2028."

program, PG&E anticipates its penetration among eligible customers to grow to around 3 percent from slightly less than 1 percent today.

- The permanent battery direct install expense program is expected to grow substantially through 2027 and subsequently decline as it is displaced by the new capital program over the 2028-2030 GRC attrition years. The new and highly targeted expense program is anticipated to grow to over 10 percent penetration among eligible customers from roughly 3 percent today; and
- The permanent battery rebate, PG&E's newest program, is expected to grow substantially in the coming years and remain steady through the GRC period as it becomes more established. It is anticipated to reach over 2 percent of eligible customers in this period, growing from less than half a percent today.

The forecasts provided are not unitized in the associated workpapers due to the complexity of unitizing such a dynamic portfolio. Within a program, customer eligibility and approved equipment continuously evolve, resulting in changes to the core costs of the program. Furthermore, battery purchases occur in bulk, while installations are continuous, resulting in a standard unit cost which appears to vary significantly from year-to-year. For example, PG&E made a bulk purchase of batteries for the RSI program in late 2023, resulting in high unit costs that would appear high in 2023 while 2024 unit costs would appear low when those batteries were subsequently installed.

2. Customer Battery Infrastructure Program (Capital MWC 21)

a. Overview

PG&E requests capital funds to implement a utility-owned battery program called the Customer Battery Infrastructure (CBI) program.[29] This program will install permanent batteries on-site for residential customers that are heavily impacted by wildfire safety outages, prioritizing customers with unique needs like low-income customers and those with medical devices. PG&E will own, install, maintain, and

[29] Referred to as BTM Capital Battery Program in tables and workpapers.

operate these batteries for the entire battery life, and remove them upon end-of-life. This program significantly improves the cost-effectiveness of its existing permanent battery direct install program by enabling PG&E to layer on additional benefits, such as optimizing battery dispatch to benefit all customers through system or local peak load reduction. Other utilities have successfully implemented programs to install, own and operate behind-the-meter energy storage, most notably Vermont's Green Mountain Power (GMP), which currently has over 5,000 such batteries installed. Similar to the GMP program, PG&E intends to use a 10-year depreciation schedule for these assets, which is a typical permanent battery system warranty period.

PG&E believes the CBI program is reasonable and beneficial for three reasons: (1) batteries for customers highly impacted by wildfire safety outages are a physical asset integral to the success of its wildfire safety programs; (2) participants will benefit by reducing not only the up-front barriers to adoption but also the ongoing challenges to optimize and operate the battery; and (3) all customers will benefit through improved cost-effectiveness of PG&E's permanent battery installations due to the amortization of costs over time (in contrast to an expense program) as well as PG&E's ability to capture system-wide and potentially local grid benefits. This approach enables PG&E to deliver a much-needed resiliency solution more affordably, consistent with the Simple Affordable Model described in Exhibit 2 Chapter 2. Each reason is discussed in greater detail below.

- <u>Permanent batteries are a wildfire risk mitigation capital asset:</u> Providing permanent battery backup systems to support highly impacted customers who are in scope for PSPS and EPSS outages enables these programs to effectively mitigate wildfire risk by minimizing the impact of outages on customers. As described in the PSPS and EPSS sections above, these programs include capital investments to increase precision of outages, removing customers from the outage scope where possible. These investments are analogous to permanent battery installations. As described above, PG&E is currently using expense dollars to directly install these

assets on customer premises today, and transitioning this activity to a utility owned model will improve affordability of this activity at scale while aligning it with the capital treatment of other physical assets that support effective PSPS and EPSS programs.

- The CBI program can benefit its participating customers by further reducing barriers to effective use of the battery through utility ownership and operation over its lifetime. Participants in PG&E's existing residential permanent battery direct-install program report that they struggle to understand how to use their battery for bill reduction and grid support. National research shows that customers with batteries tend to set their backup reserve levels too high to the detriment of other benefits.[30] This is true even when a very high value is placed on uninterrupted service. The complexity of daily optimization of battery settings can be a substantial barrier, especially for PG&E's priority customers who are often low-income or face other information and language barriers. As the entity with the most accurate and real-time information on both PSPS events and EPSS setting configuration, PG&E can actively manage battery backup levels based on the best information, yielding the maximum opportunity to use the battery to provide bill savings and grid benefits. Relatedly, utility ownership can reduce observed participant worries related to product selection, insurance and tax impacts, and maintenance. As the battery owner and operator, PG&E can work with its manufacturer and installer partners to ensure that batteries are well vetted and are operated and maintained consistent with manufacturer and industry guidelines.
- All customers benefit from the CBI program through the improved affordability relative to existing expense programs, including PG&E's ability to capture additional grid benefits through load

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30 See Berkeley Lab Energy Markets and Policy Report "Study shows that, in most circumstances, customers should maintain low reserves, prioritizing bill savings over backup power" (Oct. 8, 2024), available at: <https://emp.lbl.gov/news/study-shows-most-circumstances-customers-should-maintain-low-reserves-prioritizing> (accessed April 24, 2025).

management.[31] Several recent evaluations of the Self Generation Incentive Program (SGIP) program demonstrate that there is additional value that customer-sited batteries can provide if they are used more effectively, showing that a more optimized approach informed by more granular actual avoided cost information can drive down both GHG emissions and utility costs to all customers while delivering bill savings.[32] These study findings repeatedly find that more optimal operation increases avoided cost benefits to all customers by a factor of four or greater, as compared to typical, observed battery operation. With the best information on EPSS and PSPS outage likelihood and on granular avoided cost information, PG&E can capture that value multiplier and significantly improve the cost effectiveness of its permanent battery program.

For batteries provided to wildfire outage impacted customers, PG&E can leverage existing load management price signals and programs to capture benefits. PG&E has existing, cost-effective, year-round load management programs today that are compatible with an optimized approach where battery capacity not needed for wildfire outage mitigation can be used for bill savings via time-of-use rates while delivering system-wide load management benefits through integration with California electricity markets. Finally, load management benefits can be further increased if a location-specific distribution deferral opportunity occurs coincident with wildfire outage mitigation needs. Such a targeted deployment opportunity, if it occurs, would further

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31 PG&E notes that the CBR results for the CBI program are slightly less than the RSI program; however this CBR analysis only quantifies the outage mitigation benefit and not any avoided cost benefits. The difference in CBRs reflects only the higher unit cost for a utility-owned battery provided in Exhibit (PG&E-4), WP 6-49, note 1 as compared to Exhibit (PG&E-4), WP 6-5, note 5.

32 See Storage Optimization summary findings and section 6.7, Residential Storage Optimization, of the 2021-2022 SGIP Impact Evaluation and also See Storage Optimization summary findings and section 5, Residential Storage Optimization, of the 2023 SGIP Impact Evaluation report, available at: <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/self-generation-incentive-program/self-generation-incentive-program-evaluation-reports> (accessed April 3, 2025).

increase the load management value delivered and improve cost-effectiveness.

To offset battery O&M expense and further improve the affordability of this program, PG&E intends to introduce a graduated, on-bill, monthly fee for this service. The on-bill fee is supported by customer research and is in line with similar programs, such as the Green Mountain Power program, which has a monthly fee of $55 dollars.[33] This fee, along with hard benefits from load management would offset O&M costs and improve the affordability of the program.

b. Forecast

Table 6-24 below shows the capital forecast amounts for the new Customer Battery Infrastructure Program. As described previously, specific post Test-Year attrition is requested for all customer battery program forecasts.

33 More information about the Green Mountain Power battery program, including participant fees, available at: <https://greenmountainpower.com/rebates-programs/home-energy-storage/energy-storage/> (accessed April 24, 2025).

TABLE 6-24
CUSTOMER BATTERY INFRASTRUCTURE PROGRAM (MAT 21#)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	21#	BTM Capital Battery Program	–	–	–	–	–	–	–	$13,000	$26,000	$26,000	$26,000

Risk Mitigation for Wildfire Risk

	Risk Program ID	Risk Program Name	CBR
2	WPSPS-M009, DOVHD-M040, WEPSS-M018	BTM Capital Battery Program	1.5

PG&E's capital forecast includes battery equipment, installation and decommissioning costs, based on the best available information, including data from PG&E's existing programs.[34] PG&E's forecast is based on an expectation to install 3,500 to 4,500 batteries, recognizing that future battery installed costs are uncertain. PG&E intends to hold a competitive solicitation to ensure partners who provide the highest quality batteries and installations at the lowest cost. PG&E's forecast does not assume any tax credit: as mentioned elsewhere in this GRC, due to uncertainties about tax credit eligibility and the continuing availability of tax credits, any applicable Inflation Reduction Act tax credits would be tracked in the Tax Memorandum Account.[35]

PG&E has also quantified ongoing O&M expenses associated with the CBI program. Using indicative values for the on-bill fees and load management benefits, PG&E expects these to offset the O&M expense. Any remainder would be used to support additional battery program expenses and deliver further cost savings.

E. Compliance

1. Deferred Work Analysis

The 2023 GRC Decision (OP 4) requires PG&E to continue following the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC.[36] The Deferred Work Settlement requires PG&E to include testimony on deferred work if the following criteria are met:

- The work was requested and authorized based on representations that it was needed to provide safe and reliable service;
- PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and

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34 See Exhibit (PG&E-4), WP 6-49.

35 See Exhibit-(PG&E-10), Ch. 10 "Income and Property Taxes", Section B.1b, which discusses the Inflation Reduction Act of 2022.

36 Pursuant to D.23-11-069, p. 900, OP 4, "Pacific Gas and Electric Company shall continue to follow the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC, subject to the limitations of Public Utilities Code Section 8386.3, which restricts the diversion of revenues authorized for certain wildfire mitigation activities."

- PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.

For work covered in this Chapter, PG&E applied these criteria as explained in Analysis of "Deferred Work" discussion set forth in the Electric Distribution Forecast Summary and Investment Planning chapter.[37] This analysis is presented in the workpapers supporting that chapter.[38]

Based on this analysis, no work included in this Chapter was identified as "deferred work" under the terms of the Deferred Work Settlement.

F. Accounts

1. Retain Accounts without Modifications

a. Wildfire Mitigation Balancing Account (WMBA)

In the 2023 GRC D.23-11-069, the Commission directed PG&E to establish a one-way balancing account to record costs for wildfire mitigations. In this rate case period, PG&E is proposing to retain the WMBA as requested in Exhibit (PG&E-4) Chapter 4, Section E. PG&E summarizes its request to retain, modify, or discontinue existing cost recovery mechanisms as described in this exhibit and associated revenue requirements in Exhibit (PG&E-10), "Results of Operations," Chapter 16 "Balancing Accounts."

PG&E proposes that the costs for the wildfire mitigations in this chapter be recorded to the Wildfire Mitigation Balancing Account (WMBA). A summary of PG&E's total WMBA forecast is in Exhibit (PG&E-4) Chapter 4, Section E.

2. Discontinue Accounts

a. Microgrids Memorandum Account (MGMA) [Shawn Holder]

In the D.20-06-017, the Commission directed PG&E to establish a memorandum account for the purpose of tracking incremental electric expense and capital related costs for the Make-Ready Program for Single-Season Microgrid Solutions, the 2020 Temporary Generation Program, and the Community Microgrid Enablement Program (CMEP) in

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37 Exhibit (PG&E-4), Ch. 2, Section E.1.b.

38 Exhibit (PG&E-4), WP 2-19.

separate subaccounts. Subsequent decisions, D.21-01-018 and D.22-11-009, directed PG&E to establish separate subaccounts in the MGMA to track incremental costs for the 2021 Temporary Generation Program, the 2022 Temporary Generation Program, the development of the Microgrid Incentive Program (MIP), the implementation and administration of the MIP, and the single-season, temporary generators. As of April 14, 2023, CMEP microgrid utility upgrades and the revenue requirement for CMEP capital costs are no longer recorded to the MGMA, but are prospectively recorded to the Microgrids Balancing Account (MGBA) pursuant to D.23-04-034.

In this rate case period, PG&E is proposing to eliminate the MGMA. PG&E is able to develop a reasonable forecast for temporary generation costs and has included that forecast as part of this GRC, rendering the temporary generation subaccounts no longer necessary. Activity related to the CMEP is recorded in the MGBA as of April 14, 2023, rendering the CMEP subaccount no longer necessary. Costs recorded in the two MIP subaccounts were approved for recovery through Ordering Paragraph 11 of D.23-04-034, rendering those subaccounts no longer necessary. PG&E does not anticipate the need to record future Make Ready costs to the MGMA, rendering that subaccount no longer necessary. Thus, the MGMA is no longer necessary and PG&E proposes to close this memorandum account upon completion of a reasonableness review of the costs. PG&E summarizes its request to retain, modify, or discontinue existing cost recovery mechanisms as described in this exhibit and associated revenue requirements in Exhibit (PG&E-10), “Results of Operations,” Chapter 16 “Balancing Accounts.”

G. Conclusion

Based on the demonstration above and on the evidence presented in the associated attachments and workpapers to this chapter, PG&E respectfully requests that the Commission:

1) Adopt the expense forecasts in Section A.2, Table 6-1;
2) Adopt the capital expenditure forecasts in Section A.2, Table 6-2;
3) Adopt the specific post Test-Year attrition proposed for the Customer Battery Programs as described in Section D; and

4) Discontinue the Microgrid Memorandum Account, as described in Section F.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

WILDFIRE SYSTEM HARDENING

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
WILDFIRE SYSTEM HARDENING

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 7
WILDFIRE SYSTEM HARDENING

A. Introduction and Summary

1. Overview

The purpose of this chapter is to present the capital and expense forecast for PG&E's Electric Distribution System Hardening Program initiatives. The programs and their associated activities and costs described in this chapter are critical elements of PG&E's Wildfire Mitigation Plan (WMP) and are necessary to reduce the risk of wildfire ignitions caused by distribution facilities. The System Hardening program mitigations in this chapter include:

1) Overhead Hardening;[1]
2) Relocation of Overhead Assets to Underground (Undergrounding);
3) Line Removal and Remote Grid, including the Line Elimination Incentive Program (LEIP) for System Hardening; and
4) Integrated Planning Tool Development (IPTD).

The System Hardening Program targets High Fire Risk Areas (HFRA) and/or Tier 2 and 3 High Fire Threat Districts (HFTD) in PG&E's service territory and selects projects based on: (1) high wildfire risk miles as identified by PG&E's Wildfire Distribution Risk Model (WDRM) version 4 (v4) and generally leveraging the Electrical Undergrounding Plan's (EUP) screening process for selection and prioritization of system hardening work; and (2) overhead structures previously impacted by wildfires. PG&E refers to areas that have been impacted directly by wildfires as Fire Rebuild work or Community Rebuild work. Fire damaged assets are prioritized for rebuild and/or replacement. Replacement work includes both overhead hardening and undergrounding.

Recently, the Commission, Safety Policy Division and the Governor's office have stressed the need to carefully balance risk reduction and

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[1] PG&E has included costs associated with overhead hardening in areas that have been impacted directly by wildfires within an HFTD (referred to as Fire Rebuild work). PG&E has not included any Community Rebuild work outside the HFTD in its 2027 GRC.

affordability.[2] In PG&E's 2023 GRC Decision, the Commission stated that it was reasonable to find that ratepayers' ability to pay for safety or risk reduction is not unlimited; as with all safety measures, the Commission must consider the cost and impact on affordability.[3] PG&E understands and appreciates the need to focus on both risk reduction and affordability and, as such, PG&E is proposing a balanced system hardening portfolio that considers wildfire risk, reliability risk, and cost-effectiveness. While undergrounding is PG&E's preferred solution for mitigating ignition risk in the highest risk areas because it is the most effective way to achieve near permanent wildfire risk reduction and significantly reduce outages, PG&E recognizes that undergrounding often takes longer to execute than overhead hardening and is a more costly investment in the short-term. In the highest risk locations, the long-term benefits of undergrounding (greater wildfire risk reduction, reliability improvement, and operational cost avoidance (e.g., less vegetation management) make it the best long-term investment for customers and communities. In many other locations, however, wildfire risk can be appropriately mitigated and managed through other mitigations including a combination of overhead hardening and operational mitigations such as Public Safety Power Shutoff (PSPS) and Enhanced Power Safety Settings (EPSS).

In assessing PG&E's Test Year 2023 GRC system hardening proposal, the Commission noted that it was skeptical of PG&E's proposed system hardening pace[4] and stated that:

> [t]his decision provides PG&E an opportunity to demonstrate its capabilities at an unprecedented scale. We grant PG&E the opportunity to demonstrate that it can achieve its forecasted unit costs, risk reduction, and project timeliness, and report back on its results, which would be industry-leading outcomes if achieved.

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2 See, for example: A.24-05-008, Email Ruling Granting Cal Advocates' Request to Set December 4, 2024, Deadline for Comments on Motion and Entering Safety Policy Division Report into the A.24-05-008 Record (Dec. 2, 2024), Atch A, Safety Policy Division Evaluation Report on PG&E 2024 RAMP Application A.24-05-008, p. 82, no. 19, Recommended solutions to address findings and deficiencies, and Governor Newsom's Executive Order N-5-24, (October 30, 2024).

3 Decision (D.) 23-11-069, p. 799, Finding of Fact 98.

4 D.23-11-069, pp. 278-279.

The Commission established annual targets for risk reduction, system hardening miles and unit costs to demonstrate that PG&E can achieve its system hardening goals: (1) 18 percent risk reduction by December 31, 2026;[5] (2) harden a total of 2,008 miles;[6] and (3) achieve a four-year average unit cost of $2.97 million per mile for undergrounding.

PG&E welcomed the opportunity to demonstrate to the Commission and stakeholders that PG&E's system hardening program had matured and PG&E can meet the industry-leading targets the Commission set. Through the first year of the 2023 GRC period PG&E met its undergrounding mileage[7] and risk reduction targets[8] and projects that it will achieve its mileage and risk reduction targets for 2024, 2025, and 2026.[9] Additionally, PG&E has committed to a unit cost for undergrounding work of $2.97 million per mile in the Test Year 2027 GRC.[10]

The System Hardening program is a critical program to continue to reduce the risk of wildfire ignitions caused by distribution facilities.

2. Summary of Request

PG&E requests the Commission:

- Adopt the expense forecasts in Section A.2, Table 7-1;
- Adopt the capital expenditure forecasts in Section A.2, Table 7-2;
- Approve PG&E's proposal for of its Undergrounding Bridge Program for 2027 as described in Section C.2;

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5 D.23-11-069, p. 281. Annual amounts of 2 percent by December 31, 2023, by a total of 5 percent by December 31, 2024, by a total of 10 percent by December 31, 2025, and by at least a total of 18 percent by December 31, 2026 of the 2023 baseline risk amount.

6 D.23-11-069, p. 862, Conclusions of Law (COL) 81. The total miles include a forecast of 1,230 undergrounding miles and 778 overhead miles.

7 Advice Letter (AL) 7312-E, PG&E's Annual System Hardening Accountability Report, July 1, 2024, Attachment C, Table 2, Projected System Hardening Miles: Summary by Year and Table 4, Completed 2023 System Hardening Work (GRC-Funded via WMBA).

8 AL 7312-E, PG&E's Annual System Hardening Accountability Report, July 1, 2024, Attachment C, Table 2, Projected System Hardening Miles: Summary by Year and Table 3, Risk Reduction Percentage for Completed Projects: Summary by Year.

9 AL 7312-E, PG&E's Annual System Hardening Accountability Report, July 1, 2024, Attachment C, Table 2, Projected System Hardening Miles: Summary by Year and Table 1, Projected Risk Reduction Percentage: Summary by Year.

10 See Section C.2.b and Section E.2.

- Provide a directive that PG&E has authorization to extend funding for undergrounding beyond 2027 if PG&E's Electrical Undergrounding Plan (EUP) is not approved by September 1 each year (beginning September 1, 2027) through the Tier 2 Annual Electric True-up (AET) advice letter or another Tier 2 rate change advice letter for inclusion in rates in the following year, as shown in Section E.2, Table 7-16;
- Adopt the specific post Test-Year attrition proposed for the Undergrounding Program as described in Section C.2; and
- Consider the adjustment mechanism proposal in this GRC, if an adjustment mechanism is needed to authorize additional overhead hardening in the GRC based on the undergrounding mileage approved in the EUP. See Section E.3. for further information.

Tables 7-1 and 7-2 below show the summary of recorded adjusted and forecasted expense and capital spend, respectively.

Forecasts in this chapter are shown with no escalation included in both expenses and capital totals, except for the capital Overhead Hardening and Line Removal programs.[11] PG&E will offset escalation through work execution efficiencies to improve affordability.

[11] For more information on escalation, please refer to Exhibit (PG&E-10), Ch. 15.

TABLE 7-1
SUMMARY OF EXPENSE[a]
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	Workpaper Reference
1	AB	Misc Expense	$755	$4,819	$2,276	$3,373	$3,979	$3,280	$2,620	$3,145	WP 7-1
2	GE	Integrated Planning Tool Development	–	–	-	–	199	–	–	180	WP 7-1
3		Total	$755	$4,819	$2,276	$3,373	$4,178	$3,280	$2,620	$3,325	WP 7-1

(a) The values reflected in this table may vary from the initial Results of Operations (RO) Model provided with PG&E's GRC filing due to timing differences. The RO Model will be updated to incorporate these errata in a future submission.

TABLE 7-2
SUMMARY OF CAPITAL[a]
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast[b] 2025	2026	2027	2028	2029	2030	Workpaper Reference
1	08	E Dist. Replace OH Asset	$460,142	$280,739	$683,163	$1,008,684	$611,368	$467,304	$508,484	$237,029	$215,132	$221,109	$268,812	WP 7-6
2	3U	Inst/Rpl Wildfire Mitgt Eqpmnt	–	–	19,898	82,402	365,747	935,196	837,739	710,115	64,765	–	–	WP 7-6
3	21	Misc Capital	–	–	171	4,539	4,521	900	340	1,800	1,620	1,458	1,166	WP 7-6
4		Total	$460,142	$280,739	$703,232	$1,095,624	$981,636	$1,403,400	$1,346,563	$948,944	$281,517	$222,567	$269,978	WP 7-6

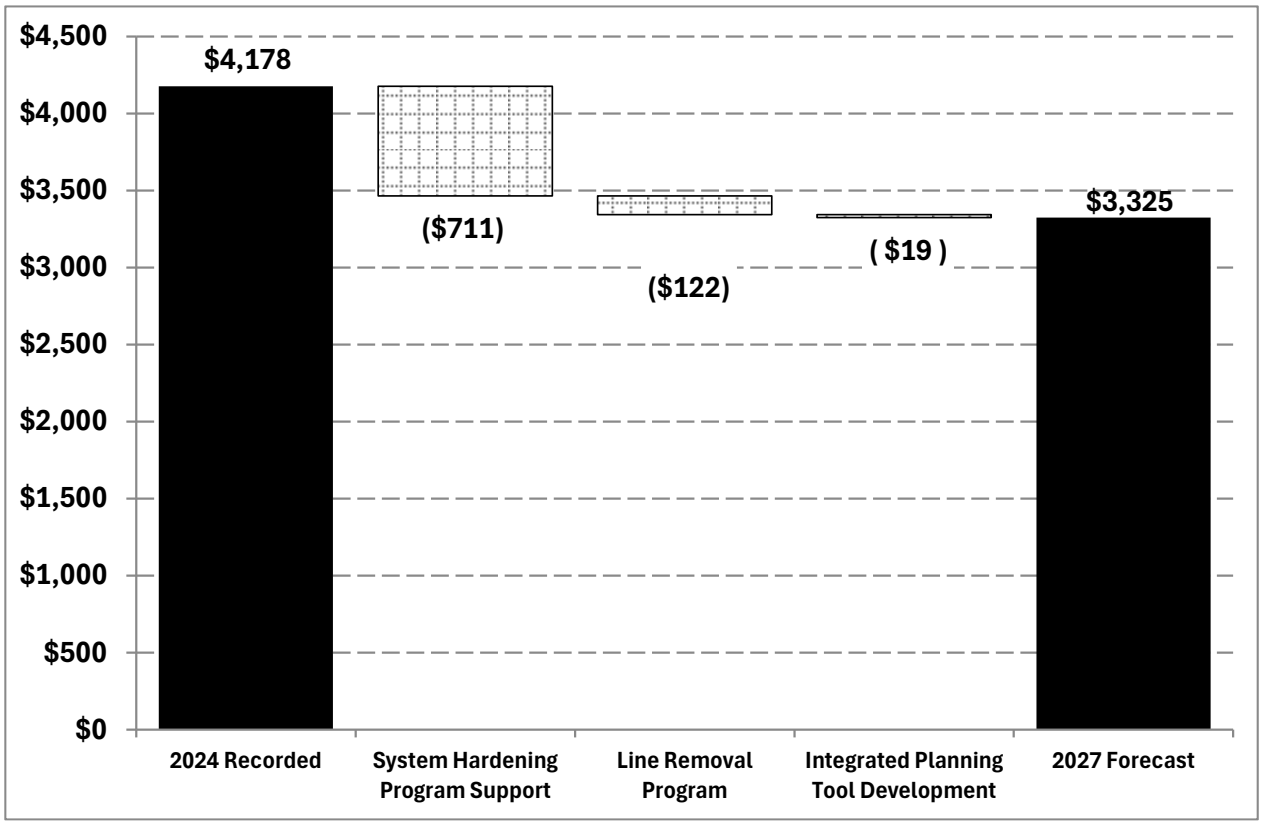
(a) The values reflected in this table may vary from the initial Results of Operations (RO) Model provided with PG&E's GRC filing due to timing differences. The RO Model will be updated to incorporate these errata in a future submission.

(b) PG&E discusses its forecast methodology for multi-year capital projects in Section C.2.b.

a. Expense

Figure 7-1 provides an expense walk identifying key drivers for the difference in the 2027 forecast compared to 2024 recorded. Each driver is summarized below.

FIGURE 7-1
EXPENSE WALK 2024-2027
(THOUSANDS OF NOMINAL DOLLARS)

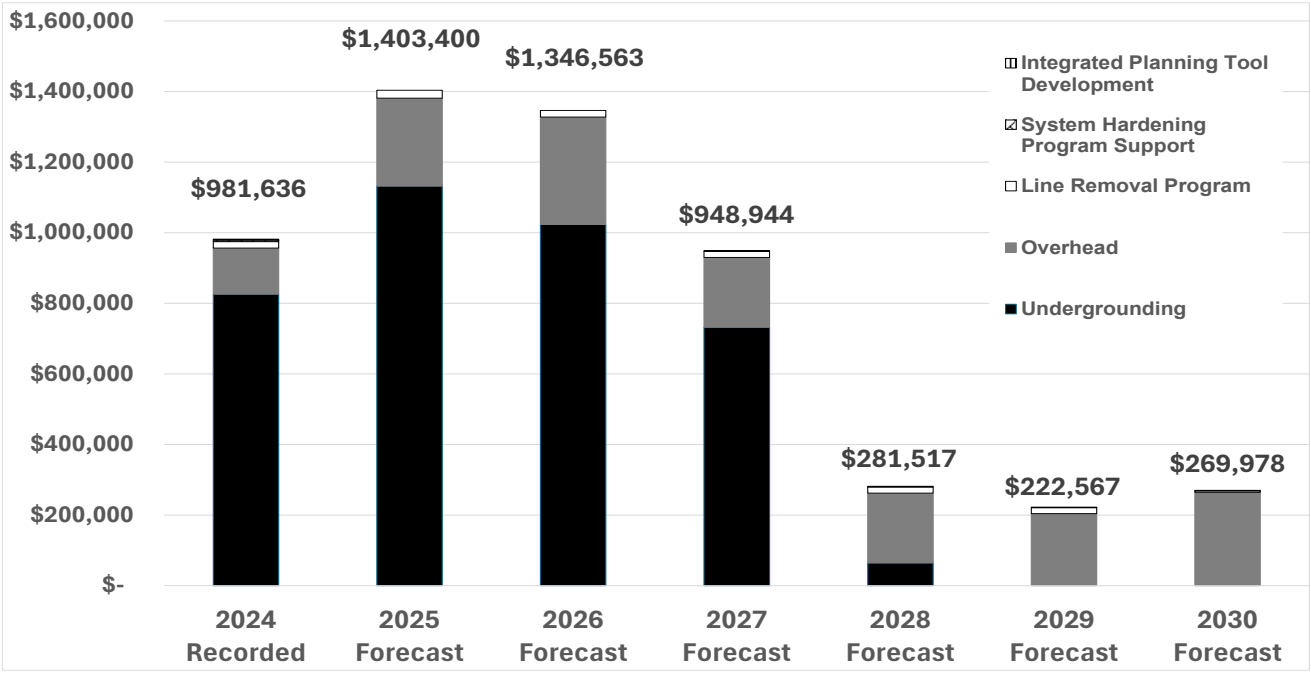


The key drivers in the 2027 expense forecast are a decrease in forecast costs for System Hardening Program Support expenses due to a lower forecast for contractor services, and a decrease in forecast costs for programmatic Line Removal work due to fewer anticipated labor hour needs.

b. Capital

Figure 7-2 below shows the capital expenditure walk from 2024-2030.

FIGURE 7-2
CAPITAL WALK 2024-2030
(THOUSANDS OF NOMINAL DOLLARS)



The System Hardening forecast has a significant decrease in forecasted costs from 2027 to 2030, because the forecast includes one year of undergrounding in 2027 (not four years as previously authorized in the 2023 GRC). It is currently expected that undergrounding work and associated cost recovery in 2028-2030 will be through the EUP.[12]

The drivers between the 2024 recorded costs and 2027 forecast amounts are as follows:

- For undergrounding, the 2024 recorded costs are higher than the 2027 forecast because 2024 includes project readiness costs for 2025 and 2026 projects,[13] whereas the 2027 forecast only includes construction costs for 2027 projects and close-out costs for 2026 projects.[14] In addition, the unit cost in 2027 is less than the recorded unit costs in 2024;

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12 See Section B.1 for further detail on the EUP Filing.

13 Project readiness costs are costs incurred prior to construction. See Section C.2.a and Figure 7-4 for further information.

14 See Section C.2.b for more information.

- For overhead hardening, the forecast for 2027 is higher than the 2024 recorded costs due to an increase in overhead miles forecast for construction in 2027 (an increase from 106 miles in 2024 to a forecast of 190 miles in 2027);[15]
- For the Integrated Grid Planning Tool Development, the 2027 forecast is lower than 2024 to reflect the maturity of the tool development, which requires less major functionality development and a shift to focus on tool enhancements and O&M activities;[16] and
- There are no significant changes in the Line Removal forecast between 2024 and 2027.

3. Risks Addressed

PG&E's forecast for System Hardening addresses the Electric Distribution-related risks described in Table 7-3.[17] Each program in this chapter identifies the risk addressed, the cost-benefit ratio (CBR) when applicable, and describes why the risk mitigation and control work is necessary and justified. A summary table of the program names, risk control or mitigation identification, and CBRs for this chapter is presented in Table 7-4.

In addition, all System Hardening programs described in this chapter are wildfire mitigations and controls which contribute to climate resilience because they address wildfire risk. For more information about the relationship between this General Rate Case filing and PG&E's climate resilience plans, see Exhibit (PG&E-2), Chapter 1.

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15 See Section C.1.b for more information.

16 See Section C.5 for more information.

17 For additional information on these risks, see Exhibit (PG&E-4), Ch. 3.

TABLE 7-3
RISKS ADDRESSED BY SYSTEM HARDENING

Line No.	Risk Name	Risk ID	Risk Description
1	Wildfire with PSPS and EPSS	WLDFR, WPSPS, WEPSS	The Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands or environment originating from PG&E assets or activities. In the near term, due to the use of Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS), we have also defined Post PSPS/EPSS Wildfire Risk as Wildfire Risk with PSPS and EPSS. This does account for the benefits and consequences of operational mitigations, such as PSPS and EPSS.
2	Failure of Electric Distribution Overhead Assets	DOVHD	This risk is defined as lack of remote operational functionality that may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.
3	Public Contact with Energized Electric Equipment	PCEEE	This risk is defined as the risk of reportable serious injury or fatality to a third-party contractor or member of the public from an interaction with intact PG&E electric assets that did not originate from asset failure.

TABLE 7-4
FOUNDATIONAL ACTIVITIES, RISK MITIGATIONS AND RISK CONTROL PROGRAMS

Line No.	MAT	Program Name	Risk Program ID(s)	CBR (2027-2030)
Risk Mitigations				
1	08W 3UG	System Hardening [Overhead]	DOVHD-M002, WLDFR-M002, PCEEE-M002	13.3
2	08W AB#	System Hardening [Remote Grid][(a)]	WLDFR-M011	14.0
3	08W 3UG	System Hardening [Underground]	DOVHD-M022, WLDFR-M022, PCEEE-M003	6.8
Foundational Activities				
4	AB#	System Hardening Program Support	WLDFR-M054	Foundational
5	GEP	Integrated Planning Undergrounding Tool Development (IPUTD)	WLDFR-M059	
6	21#	Integrated Planning Undergrounding Tool Development (IPUTD)	WLDFR-M059	

(a) System Hardening [Remote Grid] includes Line Removal and Remote Grid.

B. System Hardening Program Details

1. PG&E's System Hardening Program During the EUP Transition Period

In 2022, the California Legislature enacted SB 884, requiring the Commission to establish an expedited 10-year distribution infrastructure undergrounding program prioritizing wildfire risk reduction, public safety, cost efficiency, and reliability benefits.[18] Energy Safety has developed guidelines that set forth substantive procedural requirements for utilities to prepare and submit a 10-year EUP as authorized by SB 884.[19] The EUP Guidelines provide requirements for selecting system hardening solutions at the circuit-segment level. Once an EUP is approved by Energy Safety, and the cost recovery associated with the EUP is approved by the CPUC, undergrounding program costs no longer need to be recovered through the GRC.[20] However, not all guidelines related to the EUP have been finalized and issued and, therefore, there remains a lack of certainty when a plan could be approved and costs transitioned to EUPs.

On November 17, 2022, Energy Safety released a letter indicating the Large Electrical Corporations shall not submit a plan until the guidelines are finalized. Energy Safety issued draft EUP Guidelines in May 2024, Revised EUP Guidelines in September 2024, and Second Revised Guidelines in January 2025. Final EUP Guidelines were adopted on February 20, 2025. Energy Safety will also prepare draft compliance guidelines for public review and comment now that the program's guidelines are finalized[21] and the CPUC indicated it may update its cost recovery guidelines (SPD-15)[22] to more closely align to the final Energy Safety EUP guidelines.

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18 Senate Bill (SB) 884, §8388.5(a) and §8388.5(c)(1) and (2).

19 Office of Energy Infrastructure Safety, 10-Year Electrical Undergrounding Plan Guidelines, February 20, 2025 (EUP Guidelines).

20 Energy Safety and CPUC approval of the EUP must be received before September 1 of the calendar year for PG&E to have adequate time to transition the Undergrounding program to align with the EUP requirements.

21 EUP Guidelines, Section 4.2. The EUP program guidelines set for the requirements for submitting an EUP including a framework for selecting undergrounding projects and risk reduction requirements. The compliance guidelines will establish the types of metrics and targets for an EUP.

22 Safety Policy Division, Resolution SPD-15, (March 7, 2024).

PG&E's preferred approach was to complete the undergrounding work authorized in the 2023 GRC in December 2026 and begin cost recovery for undergrounding work via an approved EUP in January 2027.[23] However, final Energy Safety EUP Guidelines were issued much later than expected and have pushed back the feasible timing for PG&E to submit the EUP. As a result, based on the information that is currently available (i.e., pending scope of revisions to SPD-15 and issuance of Energy Safety compliance guidelines), PG&E intends to file its EUP in 2025 (at the earliest), which means EUP approval would not occur until mid- to late-2027, at the earliest. To ensure continuity of PG&E's critical undergrounding program, PG&E is requesting funding for one-year of undergrounding costs in this GRC, as described in Section C.2, and, if needed, be subject to annual extensions through the AET advice letter process or another Tier 2 rate change advice letter as described in Section E.2. PG&E's intent, dependent on the CPUC's timely resolution of any changes to SPD-15 and Energy Safety's compliance guidelines, is to file an EUP in 2025 for Phase 1 and Phase 2 approval no later than September 1, 2027 in order to transition the Undergrounding Program to EUP cost recovery in 2028.

Continuity in completing work for the Undergrounding Program is critical to its success. As background, a typical undergrounding project spans multiple years from project identification and scoping, through design, estimating, permitting, construction and close-out (see Figure 7-4 in Section C.2.a. below). Currently, a typical undergrounding project takes approximately three to four years from scoping through project completion, though projects can take longer when issues arise, such as permitting delays, construction challenges due to the presence of hard rock, steep slopes, or water crossings.

If there is a gap in funding for the Undergrounding Program, PG&E may be forced to pause in-flight projects and suspend or terminate contracts with contractors, suppliers and vendors. By suspending work, PG&E risks losing designers, engineers, construction crews, and contractors who have

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23 Due to timing required to complete undergrounding projects, certain close-out costs for undergrounding work approved in the 2023 GRC are included in PG&E's 2027 GRC. See Section C.2.

developed undergrounding expertise working on PG&E's projects. This expertise directly translates into more efficient projects and reduces the time and cost to complete undergrounding work. Suspending or losing these relationships significantly undermines the Undergrounding Program success and raises costs for customers. If PG&E suspends undergrounding work, it also risks losing undergrounding partners for a significant period as vendors will take on other work. A gap in funding would also impact the customers and communities with whom PG&E partners on undergrounding projects by causing disruptions and delays to important wildfire mitigation work. Maintaining continuity of the Undergrounding Program allows PG&E to continue reducing wildfire risk in the HFTD/HFRA and sustain program efficiencies, which ultimately translates to lower costs to customers.

Furthermore, a successful undergrounding project requires coordination among several teams of planning, engineering, estimating, contracting, permitting, purchasing, construction, and inspection professionals. Undergrounding efficiencies are realized when there is certainty around the amount of work PG&E has funding to undertake. This certainty allows PG&E to enter into long-term contracts with experienced professionals, build continuity among the program teams, and implement productivity improvements gained by experience. Absent funding certainty, PG&E cannot enter into long-term contracts and risks losing the momentum, expertise, and efficiencies developed by the Undergrounding Program over the previous years.

The focus of PG&E's system hardening program is to reduce wildfire and outage risks in the HFTD/HFRA through a combination of undergrounding, overhead hardening, and line removal. Due to the uncertainty in the timing of when undergrounding cost recovery will transition from the GRC to the EUP, authorization of funding for the undergrounding program in this GRC (both through the Undergrounding Bridge Program and annual extensions, if needed) will enable PG&E to continue executing work that reduces these risks for our communities.

2. Project Selection Framework

a. System Hardening Program

PG&E's system hardening approach generally aligns with the procedures for selecting mitigation alternatives outlined in the EUP Guidelines that were adopted February 20, 2025 (EUP Guidelines).[24] The EUP Guidelines set forth substantive procedural requirements for a Large Electrical Corporation to prepare and submit a 10-year undergrounding plan as authorized by SB 884.

PG&E identifies high-risk circuit segments to be included in its system hardening program. PG&E will identify a primary mitigation for each circuit segment (overhead hardening or undergrounding) based on the results of economic analyses (cost benefit analysis and net benefit) and the project selection framework. While PG&E will choose either overhead hardening or undergrounding as the primary mitigation, PG&E often implements a hybrid mitigation solution that consists of both overhead hardening and undergrounding on portions of the same circuit segment. As part of the system hardening project selection process, PG&E also looks for opportunities for line removal, which can entail deployment of a remote grid or the Line Elimination Incentive Program. PG&E describes these programs in Section C.3.

For circuit segments that are selected for overhead hardening as the primary mitigation, PG&E will analyze the proposed covered conductor route to determine if there are areas with tree strike risk or locations that could be subject to ingress/egress issues. Undergrounding is the most effective system hardening method to mitigate tree strike risk and to improve ingress and egress. Thus, if tree strike or ingress/egress issues are identified on a portion of a circuit segment selected for overhead hardening, PG&E may adopt a hybrid mitigation approach in which case it would underground portions of that circuit segment to significantly reduce the tree strike and/or ingress/egress risk.

Like the hybrid approach that may be adopted on a circuit segment selected for overhead hardening, PG&E may overhead harden portions

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[24] 2026-2028 Wildfire Mitigation Plan R0, Volume 1 of 2; Section 8.2.1. and Section 8.2.2.

of circuit segments initially selected for undergrounding. For example, during underground project scoping, PG&E may identify locations where it could be difficult and/or impossible to relocate lines underground. Specifically, in locations with very hard rock, limited access for undergrounding equipment, on steep slopes, and/or at water crossings, PG&E may identify that overhead hardening sections of line, instead of undergrounding them, adequately addresses the wildfire risk while working within significant constructability concerns. While wildfire ignition risk effectiveness for overhead hardening is less than undergrounding, overhead hardening lines in locations where undergrounding is extremely difficult is appropriate given the significantly lower cost as compared trying to relocate them underground at that location.[25]

Regulatory approval of an EUP and its associated cost-recovery application would likely further clarify or refine PG&E's system hardening project selection processes. For example, the EUP requires utilities to demonstrate that the work performed under the EUP has led to significant improvements in reliability. This may result in more targeted undergrounding in certain areas to reduce the impacts of operational mitigations, such as EPSS and PSPS.

Lastly, PG&E is required to address the issues raised by SPD in its RAMP Evaluation Report in its GRC. Certain SPD comments in the section on Wildfire Risk with PSPS and EPSS relate to distribution undergrounding work[26] and, because PG&E is only forecasting costs for continuing the undergrounding program adopted in the 2023 GRC—based on the 2023 GRC project selection methodology—certain 2024 RAMP comments are best addressed in the EUP proceeding.[27]

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25 PG&E's System Hardening Decision Tree is provided in PG&E's 2026-2028 Base WMP, Section 8.2.1.

26 *Id.*, Issues related to PG&E's Wildfire Risk with PSPS and EPSS are discussed on pp. 42-82.

27 Workpaper Exhibit (PG&E-2), WP 1-01 lists all the RAMP comments related to PG&E's system hardening program and identifies the proceeding in which PG&E addresses each one.

b. Fire Rebuild Project Selection and Funding

PG&E has not included a specific forecast for fire rebuild work in this GRC. If fire rebuild work is required, it will add to or replace the proactive system hardening work forecast herein. Fire rebuild work described in this chapter replaces unhardened lines damaged or destroyed by wildfires with hardened lines, whereas like-for-like asset replacement is part of PG&E's major emergency program described in Chapter 11 of this exhibit (Electric Emergency Recovery).

After a wildfire event, PG&E conducts a damage assessment and determines if damaged assets require hardening. Damaged assets that require hardening (i.e., overhead or underground) are considered for either the Fire Rebuild program (assets in the HFTD) or for the Community Rebuild program (assets outside of the HFTD).

"Community Rebuild" refers to fire rebuild work *outside of the HFTD.* This is a separate definition from "Community Rebuild in the Town of Paradise and surrounding areas," as defined in PG&E's 2023 GRC Decision (D.23-11-069). For clarity, in PG&E's 2024 WMCE Application (A.) 24-11-009, PG&E refers to "Community Rebuild in the Town of Paradise and surrounding areas" as Butte Community Rebuild Program. The fire rebuild work described in this 2027 GRC chapter does not include any Community Rebuild work other than Attachments A and B, which are required to be included by the 2023 GRC Decision. See Section D.2.d.

For Fire Rebuild and Community Rebuild work, PG&E assesses each damaged asset and whether significant rebuild is required (e.g., four or more spans and/or segments have been continuously or intermittently damaged). When significant rebuild is required, the appropriate hardening mitigation solution is determined: undergrounding, overhead covered conductor installation, complete line removal for non-returning customers, or line removal as part of a remote grid installation or the Line Elimination Incentive Program.[28] All rebuild

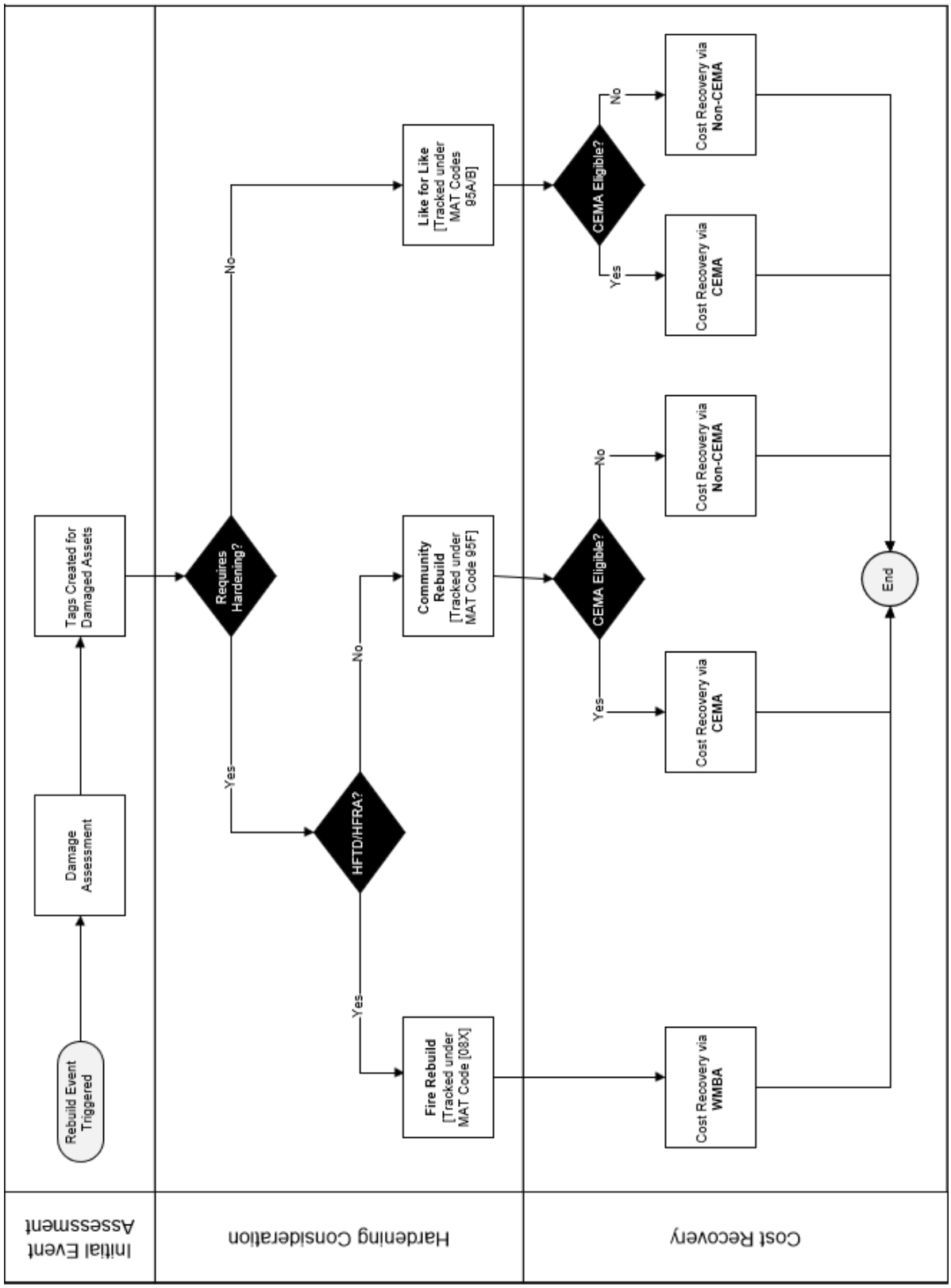
[28] Hardening for assets outside of the HFTD (Community Rebuild program) is evaluated on a case-by-case basis.

projects are executed to PG&E's hardening standard which guides the asset design in the HFTD and HFRA. If PG&E determines that a damaged asset is an idle facility or a redundant tie (i.e., a tie that is no longer required to facilitate normal switching between circuits), then line removal may be an appropriate mitigation solution. Where damaged assets serve isolated or small groups of customers in the HFTD and HFRA and temporary generation is available to serve customers in the near term, a remote grid or the Line Elimination Incentive Program may be the appropriate long-term mitigation.

Funding for fire rebuild work may be recovered in different proceedings, depending on the location and nature of work. Fire rebuild work located within Tier 2 and Tier 3 HFTDs and/or HFRAs that require system hardening will be tracked under a new MAT code, MAT 08X, and may be recovered through the GRC or an existing memorandum account. Fire rebuild work that was previously overhead hardened, or that is located outside of an HFTD or HFRA in an area impacted by a disaster declared or state of emergency by a state and/or federal agency, may be recovered through the Catastrophic Events Memorandum Account (CEMA). Electric related costs that do not meet the eligibility criteria for recovery under CEMA may instead be recorded to a non-CEMA account such as the Major Emergency Balancing Account (MEBA). Lastly, fire rebuild work located outside of the HFTDs and not associated with a declared CEMA event or eligible for MEBA recovery may be recovered through other memorandum accounts, such as the Fire Risk Mitigation Memorandum Account (FRMMA) or the Wildfire Mitigation Plan Memorandum Account (WMPMA).

Please see Figure 7-3, which depicts the Fire Rebuild cost recovery decision tree for 2027 Test-Year GRC as described above.

FIGURE 7-3
FIRE REBUILD COST RECOVERY DECISION TREE FOR TEST-YEAR 2027 GRC



C. Wildfire System Hardening Forecast

1. Overhead Hardening (Capital MAT 08W/3UG)

a. Overview

Overhead hardening includes the following components:

- Primary and Secondary Covered Conductor Replacement: Replacing bare overhead primary conductor and associated framing with conductor insulated with abrasion resistant polyethylene coatings (often referred to as “covered conductor” or “tree wire”) can be an effective mitigation in certain instances to prevent wildfire ignitions caused by distribution lines. Installing covered conductor can help reduce the likelihood of faults in instances such as: line-to-line contacts, tree branch contacts, and faults caused by animals. Installing covered conductor on secondary lines has similar resilience to faults or fire-risk events as installing it on primary lines.
- Pole Replacements: Evaluating all existing poles where a system hardening project is planned is necessary to determine whether those poles meet the strength requirements to withstand the new, heavier covered conductor and associated equipment. PG&E then replaces poles, as-needed, based on that evaluation. Often, the majority of all poles within the footprint of an overhead hardening project will need to be replaced due to the added weight of the covered conductor.
- Replacement of Non-Exempt Equipment: Replacing existing primary line equipment, such as fuses/cutouts and switches, with equipment that is certified by the California Department of Forestry and Fire Protection (CAL FIRE) as low fire risk is another component of PG&E’s System Hardening Program. This replacement work eliminates “non-exempt” overhead line equipment and devices that may generate exposed electrical arcs, sparks, or hot material during their operation.
- Replacement of Overhead Distribution Line Transformers: Upgrading transformers with newer transformers that contain fire

resistant “FR3” insulating fluid to be consistent with PG&E’s current equipment standards. “FR3” insulating fluid, a natural ester derived from renewable vegetable oils, provides improved fire safety, transformer life, increased load capability, and environmental benefits. In addition, new transformers are manufactured to achieve higher Department of Energy electrical efficiency standards.

- Framing and Animal Protection Upgrades: Replacing crossarms with composite arms, wrapping jumpers, and installing animal protection upgrades reduce animal contact and other pole-related ignition risks.
- Vegetation Clearing: Clearing vegetation undergrowth to access facilities to execute a project and bringing the vegetation clearance up to standard for the newly-installed infrastructure is a critical component of overhead hardening. Regulatory requirements mandate 4 feet of clearance all year long. If there is a change to a line’s profile, including due to deploying taller poles or wider cross arms, the vegetation must be cleared to be consistent with any profile changes and provide the required clearing for the new overhead lines.

It is reasonable to replace all the components listed above during overhead hardening as opposed to limiting which ones are replaced. In the 2023 GRC, PG&E explained why it was reasonable to replace all the components of the covered conductor system at the same time. This is because installing components at different times could necessitate resizing the pole, potentially leading to a second pole replacement. This approach might also require redeploying construction resources to the job site additional times, resulting in piecemeal work rather than more efficient, single, streamlined changeout of all related equipment. PG&E also explained that overhead assets are generally aging at a faster pace than they can be replaced under normal business processes. The Commission agreed with PG&E that it is reasonable to replace other assets on a pole when covered conductor is installed, as opposed to implementing a narrower scope of work that may artificially reduce the cost for covered conductor stating, “[g]iven PG&E’s aging infrastructure,

there is high value in doing all work needed at a given site while work crews are out at such site…" and found that PG&E's forecast unit cost struck an appropriate balance between funding all needed onsite asset replacement work and containing costs.[29]

Overhead hardening provides benefits for wildfire risk reduction. After analyzing projected performance of overhead hardened facilities on more than 2,700 outage types, PG&E currently estimates that overhead hardening will reduce 67 percent of the distribution overhead asset ignitions caused by equipment failures or external contact/strikes with energized lines, such as vegetation tree strikes.[30] When used in combination with other mitigations such as EPSS and Down Conductor Detection (DCD), overhead hardening reduces ignition risk by approximately 79 percent.

Overhead hardening is a mitigation for the Wildfire with PSPS and EPSS (WLDFR, WPSPS, WEPSS), Failure of Electric Distribution Overhead Assets (DOVHD), and Public Contact with Energized Electric Equipment (PCEEE) risks.[31] As described above, overhead hardening reduces wildfire risk and reduces EPSS outage frequency because covered conductor reduces the likelihood of ignition if there is equipment failure or tree strike on PG&E's overhead assets. Covered conductor also mitigates the potential for harm or injury to members of the public if they come into contact with an energized line. The program has a positive CBR, indicating that the program's risk benefits outweigh the costs.

b. Forecast

Table 7-5 provides PG&E's recorded and forecast amounts for Overhead System Hardening.[32]

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29 D.23-11-069, pp. 260-262.

30 2026-2028 PG&E Wildfire Mitigation Plan R0; Section 8.2.5.

31 For definitions of each risk, please see Table 7-3.

32 See Exhibit (PG&E-4), WP 7-11, line 3.

TABLE 7-5
OVERHEAD HARDENING (MAT 08W / 3UG)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast[(a)] 2025	2026	2027	2028	2029	2030
1	08W 3UG	Overhead Hardening	$432,992	$109,112	$292,848	$130,520	$130,579	$248,940	$304,493	$197,282	$197,487	$204,130	$264,630

Risk Mitigation and Control Programs

	MAT	Risk Program ID	Risk Program Name	CBR
2	08W 3UG	DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening (Overhead)	13.3

(a) PG&E discusses its forecast method for multi-year capital projects in Section C.2.b.

Table 7-6 provides a summary of the overhead hardening miles, unit cost and total risk reduction forecast for 2027 to 2030.

TABLE 7-6
OVERHEAD HARDENING (08W/3UG)
FORECAST UNITS OF WORK, UNIT COST AND RISK REDUCTION

Line No.		2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	Total
1	Units (Miles)	190	190	190	190	760
2	Forecast Cost ($M)/Mile	$1.02	$1.03	$1.05	$1.07	N/A
3	Risk Reduction					4%

The forecast for overhead hardening is informed by PG&E's 2023 and 2024 recorded costs plus the costs for transformers (approximately $20,000 per transformer).[33] In the 2023 GRC, the cost for transformers was centralized,[34] but is now allocated to individual programs in 2027. The 2027 unit cost forecast is a slight decrease compared to the 2024 recorded cost, $1.09/mile, driven by efficiencies in the overhead hardening program. The 2027 forecast cost is higher than the 2024 recorded amount due to the increase in units expected to be constructed. The overhead hardened miles completed in 2024 were nearly 106 miles compared to a forecast of 190 miles of overhead hardening in 2027.

The forecast number of overhead hardening miles is based on the miles PG&E needs to harden to achieve its risk reduction target.[35] PG&E estimates that it will reduce ignition risk by approximately 4 percent through overhead hardening during the GRC period.[36] As

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33 The transformer allocation costs were calculated using historic data to determine an average cost for the number of transformers used per mile and the types of transformers used. The historic average transformer cost per mile was then multiplied by the forecast mileage.

34 A.21-06-021, Exhibit (PG&E-4), Ch. 18.

35 See Exhibit (PG&E-4), WP 7-10, line 3 and WP 7-12.

36 The total risk reduction target for the four-year period is expected to be 4 percent, however the risk reduction per mile is expected to decrease over time as the highest risk locations are targeted first. This results in a diminishing annual risk reduction target. The same assumption is applicable to all system hardening work including undergrounding and line removal.

discussed in Section E.3, PG&E may request a mechanism to adjust the overhead hardening miles once the EUP Plan is approved if needed to enable sufficient funding to meet combined risk reduction targets across all system hardening activities.

The capital costs for a system hardening project (overhead hardening, undergrounding, and line removal) are incurred over the full lifecycle of a project (e.g., approximately three to four years for undergrounding). Because costs are incurred over multiple years, the overall program cost forecast for a given year is not simply the unit cost multiplied by the number of miles. Rather, the costs for preconstruction, construction, and post-construction are spread across multiple years as illustrated in Figure 7-4.

Forecasts for Overhead Hardening capital costs are shown with escalation applied to the unit cost assumptions.

2. Undergrounding (Capital MAT 3UG)

a. Overview

PG&E requests funding for two categories of undergrounding costs in this 2027 GRC: (1) a minimum one-year extension of its 2023-2026 Undergrounding Program (Undergrounding Bridge Program) until PG&E transitions cost recovery of undergrounding work to the EUP; and (2) close-out costs related to the undergrounding work approved in the 2023 GRC.

PG&E's Undergrounding program, which includes the proposed Undergrounding Bridge Program and close-out costs forecasted in this GRC, is focused on mitigating potential catastrophic wildfire risk and outage reliability risk caused by distribution overhead assets. The primary benefits provided by undergrounding are: (1) near permanent ignition risk reduction from overhead electric distribution equipment and (2) avoiding customer reliability impacts from deploying PSPS and EPSS to mitigate wildfire risk on overhead lines.

Undergrounding is a mitigation for the following RAMP risks: Wildfire with PSPS and EPSS (WLDFR, WPSPS, WEPSS), Failure of Electric Distribution Overhead Assets (DOVHD), and Public Contact with

Energized Electric Equipment (PCEEE). Relocating overhead distribution lines underground is the most effective way to achieve near permanent Wildfire risk reduction and significantly reduces outage program risk from PSPS and EPSS. PG&E assessed the effectiveness of each of the mitigation alternatives (undergrounding, overhead hardening, overhead hardening with EPSS, line removal) against more than 2,700 outage combinations that occurred in PG&E's HFTD during wildfire season between 2015-2024. Undergrounding primary distribution lines is approximately 98 percent effective at mitigating wildfire risk on the lines undergrounded.[37]

PG&E also analyzed the reliability performance on sections of circuits where undergrounding was performed in 2022 and 2023 to quantify overall improvements to service reliability. PG&E's analysis included approximately 750 outages between 2021 and 2024 and showed an approximate 90 percent reduction in faults that resulted in sustained outages after the undergrounding work was completed.[38] Undergrounding is PG&E's preferred solution for mitigating ignition risk in the highest risk areas where the long-term benefits of undergrounding include greater wildfire risk reduction, reliability improvement, and ongoing operational cost avoidance.

Undergrounding also mitigates the potential for harm or injury to members of the public by reducing the likelihood of contact with an energized line. The program has a positive CBR, indicating that the program's risk benefits outweigh the costs.

1) Undergrounding Bridge Program and Annual Extension

PG&E is requesting Commission approval of an Undergrounding Bridge Program and annual extension to continue its Undergrounding Program work given the uncertain timing for EUP approval. PG&E proposes funding for undergrounding 307 miles in 2027 as set forth in PG&E's 2026-2028 Base Wildfire Mitigation Plan (WMP), which is consistent with the average annual

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37 2026-2028 Wildfire Mitigation Plan R0, Table PG&E-8.2.1-3.

38 2026-2028 WMP R0; Section 8.2.2.

undergrounding mileage approved in the 2023 GRC Decision. This continuance will serve as a funding bridge from the end of the 2023 GRC until an approved EUP goes into effect. Given the time to develop and review an EUP, including the SB 884-defined 20-month review and approval process, PG&E anticipates receiving EUP approval in mid- to late-2027, which would allow PG&E to start recovering undergrounding costs within an EUP program in 2028.

However, given the uncertainty associated with the plan finalization, review, and approval for this first-of-its-kind, 10-year EUP with Energy Safety and the Commission, PG&E also requests that the Commission authorize PG&E to include additional Annual Extensions for undergrounding based on the 2028 WMP commitment of 400 miles through the AET advice letter process or another Tier 2 rate change advice letter until funding approval transitions to the EUP. This Annual Extension proposal is discussed in Section E.2.

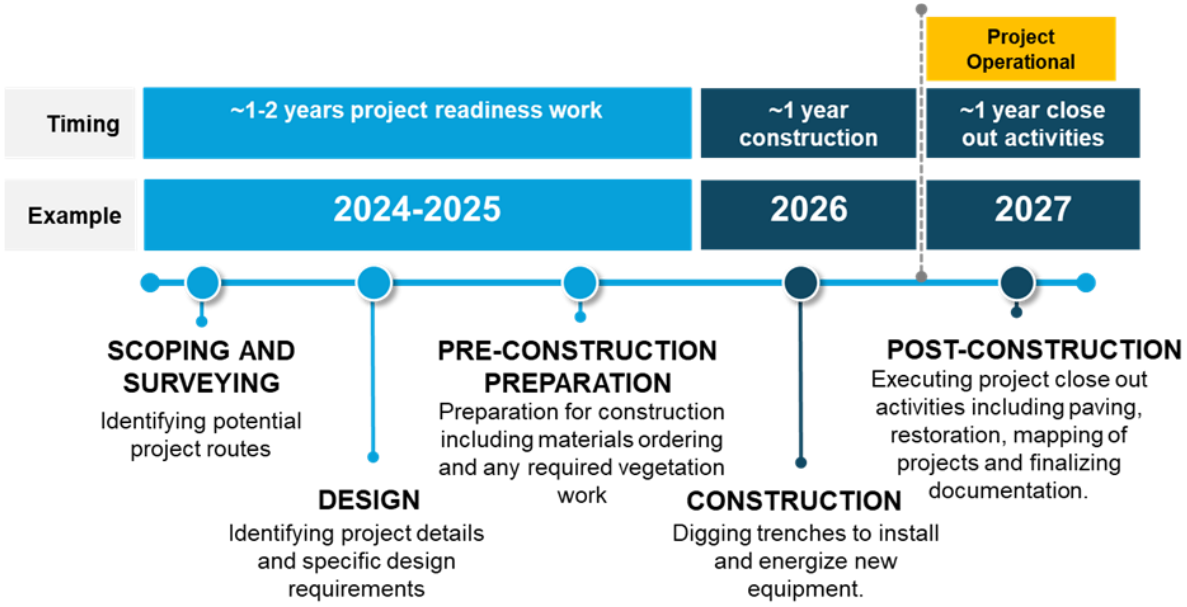
PG&E is making this request because: (1) due to the timing of the issuance of final EUP guidelines, PG&E is unable to file an EUP that would go into effect January 2027 and therefore risks having a funding gap from the end of the 2023-2026 GRC period until the start of an EUP; and (2) it is important to maintain Undergrounding Program continuity in order to continue addressing wildfire risks and sustain the labor, materials, and equipment markets that have been established in PG&E's service territory since 2021, as discussed in Section B.1.

2) Undergrounding Close-Out Costs

PG&E is also forecasting close-out costs related to the undergrounding work approved in the 2023 GRC. Typically, an undergrounding job takes approximately three to four years to complete and includes project readiness work (e.g. project scoping, design, estimating, permitting), construction, and project close-out activities. Given the time required to design, construct, and close out an undergrounding project and the 4-year GRC cycle, PG&E regularly incurs project readiness and project close-out costs in a

prior GRC (readiness costs) or subsequent GRC (close-out costs) compared to the project operative date. For example, our 2023 and 2024 recorded costs included close-out costs from projects constructed in 2021 and 2022. Based on these assumptions for the program lifecycle, there are close-out costs for projects incurred in 2026 for project authorized in the 2023 GRC. The figure below illustrates a typical timeline for undergrounding project activities over the project lifecycle. Overhead hardening project costs can also cover multiple years.

FIGURE 7-4
ILLUSTRATIVE EXAMPLE OF A PROJECT LIFECYCLE



Undergrounding electric distribution system assets follows the same general process as most utility construction work. PG&E engages with customers, property owners, and communities through the entire process of planning an undergrounding project to partner, coordinate, and share information. This general process includes:

- Project Planning and Scoping: The undergrounding program focuses on circuits in the HFTD/HFRA. Project planning and scoping consists of identifying, developing, and defining an Electric Distribution asset requiring undergrounding. When scoping

projects, PG&E balances risk reduction, constructability, and affordability when selecting the appropriate mitigation approach.

- Engineering and Design: Engineering and design consists of developing the comprehensive design for the new assets to be installed underground and identifying materials needed to execute the project. This includes designing the trench, bore tunnel, or other underground pathway for the conduit and electric cable, as well as the boxes, switches, transformers or other connections needed to integrate with customer services.

  The project scoping and design phases address and plan for constructability issues, which include the local geology (i.e., whether hard rock exists), existing underground utilities (including water, natural gas and drainage systems), plans for future road widening, sensitive environmental and/or cultural resources, and other factors.

- Material Acquisition: Material acquisition includes sourcing, purchasing, storing, and staging materials needed for undergrounding projects. Material acquisition also includes developing a sustainable supply chain to ensure availability of materials and securing favorable rates through long-term contracting.

- Permitting and Land Rights: Undergrounding projects may encounter sensitive resources, such as waterways, animal habitats, and cultural resources. PG&E reviews every undergrounding project to determine and implement necessary construction impact mitigation measures and best management plans to mitigate disturbances and engages key agencies, cities, counties, tribes, individuals and other stakeholders early and often to obtain necessary permits and mitigate risks associated with permitting and environmental considerations. PG&E may adjust project designs or construction plans to avoid sensitive resources as a result of this process. Additionally, for undergrounding work on private property, PG&E acquires the appropriate land rights, which generally involves acquiring easements for individual property owners. PG&E's existing land rights for overhead powerlines often do not grant the

right to install underground assets in the same configuration and thus require that PG&E acquire new or expanded land rights.

- Construction: The actual construction phase of an undergrounding project is the most labor-intensive and community impacting phase of the project. Traffic control is often deployed to keep construction crews and community members safe as undergrounding is frequently performed in or adjacent to public roads. Construction can also be subdivided into the following two phases (although the phases may overlap): (1) civil construction including trenching and installing the conduit and boxes, and (2) electric construction involving pulling cable through the installed conduit and connecting the cable to equipment installed inside the boxes. At the end of the construction phase, service to impacted customers is converted from the existing overhead powerlines to the new, underground lines and the existing overhead distribution lines are removed.
- Quality Control and Inspections: Quality inspection of underground assets is performed throughout the construction phase, including when the trench is open or electric cables are being pulled and connected to equipment. At the end of construction, PG&E conducts a fire safe audit in conjunction with energizing the new underground line. Quality validation and inspection activities must be carefully timed and executed in partnership with construction activities.
- Mapping, Documentation, and Close Out: Mapping, documentation, and close out involves completed paving and restoration at the job site, permanently documenting the assets that have been installed as part of undergrounding projects and removing from the geospatial maps the overhead lines that have been eliminated, as well as other administrative project close-out activities.

b. Forecast

Table 7-7 shows the recorded and forecast amounts for Undergrounding.[39]

[39] See Exhibit (PG&E-4), WP 7-11, line 2.

TABLE 7-7
UNDERGROUNDING (MAT 3UG)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast[a] 2025	2026	2027	2028	2029	2030
1	08W 3UG	Undergrounding	$11,942	$164,626	$404,864	$939,573	$825,939	$1,132,322	$1,023,095	$732,425	$64,765	–	–

Risk Mitigation and Control Programs

	MAT	Risk Program ID	Risk Program Name	CBR
2	08W/ 3UG	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening (Underground)	6.8

(a) PG&E discusses its forecast method for multi-year capital projects in Section C.2.b.

Capital costs for a system hardening project (overhead hardening, undergrounding, and line removal) are incurred over the full lifecycle of a project consistent with the undergrounding lifecycle shown in Figure 7-4. In Table 7-8, we show the multi-year cost forecast for each Project Year to illustrate when the capital expenditures associated with a Project Year's mileage actually occur.[40] For instance, in line 2, undergrounding miles completed in 2027 incur approximately $216 million in readiness capital costs in 2025 and 2026. The bulk of the construction work occurs in 2027, where PG&E forecasts approximately $651 million in capital costs. Even though these 2027 undergrounding miles are completed in 2027, there are additional close-out costs associated with these 2027 projects in 2028. The 2027 unit cost is the sum of the multi-year capital expenditures associated with projects placed in service in 2027.

This concept of incurring costs for a single project over multiple years applies to PG&E's capital expenditures forecast in Table 7-7. The costs in each year include the cumulative readiness work, construction work, and close-out costs from projects with in-service dates across several years. Table 7-7 also reflects the transition to cost recovery through the EUP, expected to begin in 2028. Only close-out costs associated with 2027 Undergrounding Bridge Program would continue through GRC recovery in 2028.[41] As such, the simple escalation approach described in Exhibit (PG&E-11) is not appropriate for the Undergrounding program for years 2028-2030. PG&E requests that the specific amount presented in Table 7-7 for each of the attrition years be separately authorized in this GRC.[42]

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40 See Exhibit (PG&E-4), WP 7-10, line 2 and WP 7-11.

41 This assumption is based on an EUP approval in mid- to late-2027. If the annual extension mechanism is required for Undergrounding work in 2028 and beyond, the total annual extension forecast amount would be incurred over a multi-year period to account for the timing of readiness costs, construction costs and close-out costs.

42 Attrition adjustment policies and mechanics, including discrete expense and capital programs, are addressed in Exhibit (PG&E-11), Ch. 1, 2, and 3.

TABLE 7-8
UNDERGROUNDING MULTI-YEAR BUDGET
[TABLE IS ILLUSTRATIVE ONLY]

Line No.	Year	Underground 2024	2025	2026	2027	2028	2029	2030	Total Project Cost
1	Miles Used and Useful				307				
2	2027 Project Forecast ($'M)	–	$30	$186	$651	$65	–	–	$932

2023 GRC Close-out Costs

PG&E's forecast includes the close-out costs for projects that were funded in the 2023 GRC and completed construction in 2026. Close-out costs are: (1) the costs to finish mapping a completed undergrounding project in PG&E's Geographical Information System (GIS), PG&E's system of record; and (2) final project close-out costs such as restoration, permanent easement acquisition, and quality control and inspections. It takes several months or more for PG&E to complete mapping in GIS and to accumulate all the final project costs from vendors and contractors. Therefore, the forecast close-out costs for projects completed in 2026 are based on the estimated percentage that close-out costs are of final total project costs. To determine this percentage, PG&E analyzed undergrounding projects completed between 2019-2023 and determined that close-out costs represent 7 percent of the total project costs. The forecast close-out costs of $65 million in Table 7-8 above are 7 percent of the forecast total project costs for projects that were funded in the 2023 GRC and completed in 2026.[43]

Undergrounding Bridge Program

PG&E's forecast for the 2027 Undergrounding Bridge Program is a continuation of the mileage and unit cost approved in the 2023 GRC Decision.

PG&E is forecasting 307 miles for 2027. In the 2023 GRC the Commission approved 1,230 miles of undergrounding.[44] PG&E's forecast for undergrounding miles in 2027 is based on the average of the total undergrounding miles approved in the 2023 GRC (1,230 miles/4 = 307.5 miles). This also aligns with our WMP mileage commitment for 2027.

PG&E's forecast unit cost equals the Commission's approved average unit cost for undergrounding in the 2023 GRC ($2.97 million per

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43 See Exhibit (PG&E-4), WP 7-10, line 2 and WP 7-11.

44 D.23-11-069, p. 800, Findings of Fact, 108.

mile)[45] increased by $55,000 per mile[46] to account for transformers that were centralized in the 2023 GRC[47] but are allocated to individual programs in 2027.

PG&E's forecast for risk reduction from undergrounding is 2.7 percent based on 307 miles of undergrounding in 2027.

The 2027 forecast unit cost of $3.03 million per mile is less than the 2024 recorded unit cost of $3.2 million per mile. PG&E discusses undergrounding unit costs and cost savings opportunities in Section D.2.c below.

3. Line Removal Program (Capital MWC 08W/3UG, 21#; Expense MWC AB#)

a. Overview

The Line Removal Program includes the following activities:

- Remote Grid Deployment: Project screening, development, engineering, contracting, permitting, procurement, and installation of remote grids;
- Line Elimination Incentive Program (LEIP): Project development and financial incentives for agreements with property owners to permanently remove PG&E electric service;
- Line Removal: Removal of overhead primary conductor where it is determined to no longer be needed (including removal associated with remote grid deployment and LEIP);
- Remote Grid Program Management: Programmatic work to systematize PG&E's processes for evaluating, designing, deploying, and operating remote grids; and
- Remote Grid IT Enhancements: IT enhancements to ensure reliable and efficient operations and maintenance of remote grids.

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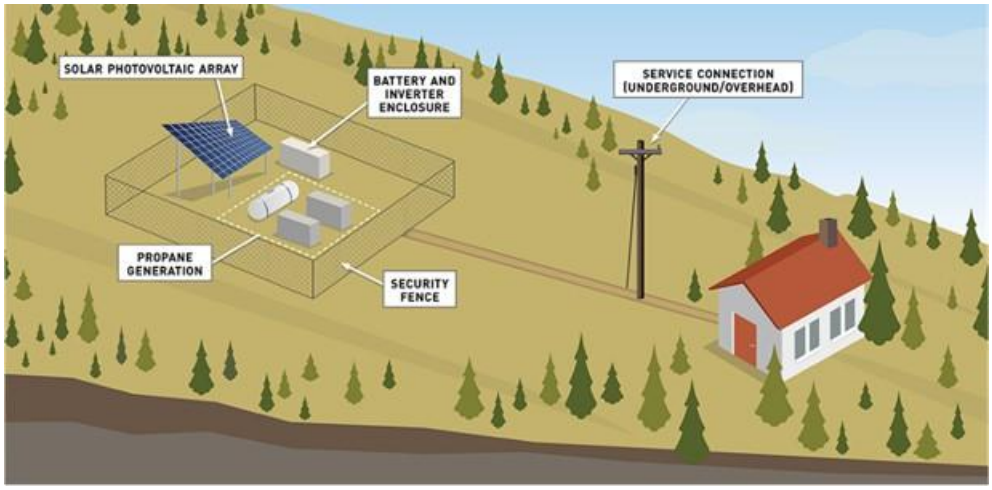
45 D.23-11-069, pp. 799-800, Findings of Fact, 105.

46 The transformer allocation costs were calculated using historic data to determine an average cost for the number of transformers used per mile and the types of transformers used. The historic average transformer cost per mile was then multiplied by the forecast mileage.

47 A.21-06-021, Exhibit (PG&E-4), Ch. 18.

FIGURE 7-5
ILLUSTRATIVE EXAMPLE OF A REMOTE GRID



The Line Removal Program is a cost-effective mitigation for Wildfire (WLDFR) risk. Remote grids allow PG&E to reduce wildfire ignition risk by enabling PG&E to remove overhead distribution lines in HFRA/HFTD that serve a small number of customers at the outskirts of the distribution system. Remote grids provide utility service using standalone power systems and service connections for continuous, permanent energy delivery in remote locations (see Figure 7-5 that depicts a remote grid configuration). Resolution E-5132 approved PG&E's Standalone Power System Supplemental Provisions Agreement and limited its use in aggregate to two megawatts of historical measured peak customer load.[48] PG&E evaluates potential opportunities for line removal via remote grid or LEIP within the broader system hardening workplan. By installing a remote grid and eliminating overhead distribution lines in HFRA/HFTD, PG&E aims to: (1) reduce the likelihood of fire ignition due to damage or failure of such lines; and (2) eliminate or reduce the cost to harden the lines and perform line maintenance and vegetation management to mitigate wildfire risks. In addition, remote grids can be a fire rebuild solution where a wildfire has damaged electric distribution infrastructure in remote areas.

[48] Resolution E-5132 (March 18, 2021).

Where a remote grid is infeasible due to unique site or customer factors, PG&E may proceed with the Line Elimination Incentive Program (LEIP), which is a mutual agreement with a property owner to permanently remove PG&E electric service at a property. Similar to a PG&E remote grid, the LEIP enables PG&E to remove overhead distribution lines in HFRA/HFTD where the LEIP is projected to be a cost-effective alternative to other forms of system hardening or fire rebuild.

If PG&E determines that an overhead distribution line is an idle facility or a redundant tie (i.e., a tie that is no longer required to facilitate normal switching between circuits), then PG&E may proceed with line removal without a remote grid deployment or LEIP agreement.

b. Forecast

Tables 7-9[49] and 7-10[50] show recorded and forecast amounts for the Line Removal Program.

[49] See Exhibit (PG&E-4), WP 7-3, line 2 for Remote Grid PMO and line 3 for LEIP.

[50] See Exhibit (PG&E-4), WP 7-11, line 4 for Line Removal and line 9 for Remote Grid IT Work.

TABLE 7-9
LINE REMOVAL PROGRAM (AB#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	Forecast 2024	2025	2026	2027
1	AB#	Remote Grid PMO	$755	$1,617	$1,957	$2,069	$1,927	$1,745	$1,745	$1,745
2	AB#	Line Elimination Incentive Program	–	3,202	2	426	940	660	–	1,000
3		Total	$755	$4,819	$1,959	$2,495	$2,867	$2,405	$1,745	$2,745

Risk Mitigation and Control Programs

	MAT	Risk Program ID	Risk Program Name	CBR
4	AB#	WLDFR-M011	System Hardening (Remote Grid)	14.0

TABLE 7-10
LINE REMOVAL PROGRAM (08W / 3UG, 21#)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast[(a)] 2025	2026	2027	2028	2029	2030
1	08W 3UG	Line Removal	$184	$2,701	$5,040	$14,793	$16,596	$21,238	$18,635	$17,437	$17,645	$16,979	$4,181
2	21#	Remote Grid IT Work	–	–	$171	$4,539	$1,615	$900	$340	–	–	–	–
3	08W 3UG 21#	Total	$184	$2,701	$5,211	$19,332	$18,210	$22,138	$18,975	$17,437	$17,645	$16,979	$4,181

Risk Mitigation and Control Programs

	MAT	Risk Program ID	Risk Program Name	CBR
4	08W 3UG 21#	WLDFR-M011	System Hardening (Remote Grid)	14.0

(a) PG&E discusses its forecast method for multi-year capital projects in Section C.2.b.

TABLE 7-11
LINE REMOVAL (08W/3UG)
FORECAST UNITS OF WORK, UNIT COST AND RISK REDUCTION

Line No.		2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	Total
1	Units (Miles)	10	10	10	10	40
2	Forecast Cost ($M)/Mile	$1.71	$1.73	$1.75	$1.78	N/A
3	Risk Reduction					0.4%

As detailed in Table 7-9, the forecast for Remote Grid PMO expense is based on estimated steady-state staffing and hours using 2024 numbers as a baseline. The forecast estimates the number of labor hours spent on programmatic remote grid work that is not attributable to a remote grid capital project and uses a labor rate assumption to calculate the annual forecast.[51] The 2027 expense forecast decrease compared to 2024 recorded is driven by a modest decrease in labor hours and other costs as some of the efforts to systematize remote grid work are completed. Escalation was not applied to the Remote Grid PMO expense forecast since PG&E expects the decrease in labor hours to offset escalation in labor rates.

Also shown in Table 7-9, the forecast for the LEIP expense is based on LEIP project values from 2023-2024 applied to a limited number of forecasted projects.[52] PG&E typically considers LEIP projects where electric service via a Remote Grid is infeasible, where the property owner is receptive to terminating electric utility service, and where other system hardening alternatives are less cost-effective or are infeasible. This can result in high year-to-year variation. In 2023 and in 2024 PG&E had two LEIP projects in process each year (with one of those projects completing each year), and the 2027 LEIP forecast assumes the same project count. Escalation was not applied to the LEIP expense forecast because LEIP costs are not driven by labor rates nor materials costs.

51 Exhibit (PG&E-4), WP 7-3, line 2.

52 Exhibit (PG&E-4), WP 7-3, line 3.

Table 7-10 shows the annual capital expenditure forecast for Line Removal, which includes the cumulative readiness work, construction work, and close-out costs from projects with completion dates across several years. The capital forecast for Line Removal was developed using initial scoping of the system hardening workplan to identify remote grid opportunities. The forecast uses estimates for line removal mileage per project and cost per remote grid informed by project costs from 2021-2024.[53] Table 7-11 shows the units (miles) to be completed each year and forecast unit cost. However, similar to overhead hardening and undergrounding, line removals with remote grid are multi-year projects, so individual project capital expenditures span across multiple years of deployment.

The 2027 capital forecast for Line Removal is higher than 2024 recorded due to a planned increase in line removal miles and deployment of remote grids in HFRA/HFTD. PG&E has gradually increased its annual deployment of remote grids, reaching 11 operational remote grids as of the end of 2024, which represents more than 9 miles of overhead line removal enabled. (Note: additional historical line removal has been completed without a remote grid project or LEIP agreement where PG&E has determined that an overhead distribution line is an idle facility or a redundant tie.) PG&E expects to deploy remote grids for system hardening that enable approximately 40 miles of line removal in 2027-2030. Forecasts for Line Removal capital costs are shown with escalation applied to the unit cost assumptions.

As shown in Table 7-10, for Remote Grid IT work, PG&E does not forecast spending after 2026. The recorded costs represent IT enhancements to ensure reliable and efficient operations and maintenance of remote grids.[54]

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53 See Exhibit (PG&E-4), WP 7-11, line 4. See also Exhibit (PG&E-4), WP 7-14.

54 Exhibit (PG&E-4), WP 7-11, line 9.

4. System Hardening Program Support Costs (Expense MAT AB#)

a. Overview

The System Hardening Program Support expense items include contractor costs to support risk analysis, project selection, and quality assurance for undergrounding work such as Advanced Technology solutions. PG&E regularly hires contractors in areas of expertise where needed, to support its System Hardening Program and anticipates that it will continue to do so during the 2027 GRC period.

System Hardening Program Support expenses is a foundational activity for Wildfire risk. These activities directly support the Overhead Hardening, Undergrounding, and Line Removal programs described above, which in turn directly reduce the likelihood of wildfire caused by an ignition from PG&E assets.

b. Forecast

Table 7-12 shows recorded and forecast amounts for System Hardening Program Support.[55]

[55] See Exhibit (PG&E-4), WP 7-3, line 4.

TABLE 7-12
SYSTEM HARDENING PROGRAM SUPPORT EXPENSES (AB#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast[a] 2025	2026	2027
1	AB#	System Hardening Program Support	–	–	$317	$878	$1,111	$875	$875	$400

Risk Mitigation and Control Programs

	MAT	Risk Program ID	Risk Program Name	CBR
2	AB#	WLDFR-M054	System Hardening Program Support	Foundational

The System Hardening Program Support expense forecast shown in Table 7-12 above was developed based on historic spending from 2023 and 2024 and expected costs for 2025 and 2026. The 2027 forecast is a decrease as compared to 2024 recorded that is driven by anticipated changing needs for contractor support.[56]

Forecasts are shown with escalation included in the total forecast.

5. Integrated Planning Tool Development (IPTD) (Capital MAT 21#, Expense MAT GEP)

a. Overview

PG&E's Integrated Planning Tool Development (IPTD) program develops technology solutions to enhance the System Hardening team's ability to screen and select projects, analyze risk, and prioritize work to ensure compliance with regulatory guidelines and remain adaptable to evolving enterprise needs. The IPTD suite of products integrates different risk models and financial analysis through a common technology platform (Palantir Foundry). IPTD is used in PG&E's System Hardening Program to perform the following activities:

- Circuit Segment Analysis and Selection: Enable the evaluation and selection of circuit segments for inclusion in the System Hardening portfolio in a detailed, scalable, and transparent manner.
- Project Scoping and Design: Accelerate and mature the scoping and initial work planning activities for circuits selected to be part of the System Hardening Program and assess alternative mitigations; and analyze wildfire and reliability risk reduction.
- Portfolio Management and Reporting: Facilitate analysis and reporting of the System Hardening portfolio using a "Portfolio Insights" tool.

During the GRC period IPTD activities will include:

1) Stabilizing core functions to support project-level and aggregate risk analysis, risk reduction analysis, and comparison of alternative mitigation strategies.

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56 See Exhibit (PG&E-4), WP 7-3, line 4.

2) Incorporating new features, such as developing Key Decision-Making Metrics (ignition likelihood, ignition consequence, ignition risk, reliability likelihood, reliability consequence, reliability risk and overall utility risk) to evaluate the efficacy of system hardening projects and quantifying risk reduction.
3) Integrating new tools and data sets into IPTD, developing processes for updating system baselines, conducting model backtesting, developing model retention policies and supporting change management.
4) On-going operations and maintenance.

The IPTD program is a foundational activity for Wildfire risk. The technology developed through this program directly supports the Overhead Hardening, Undergrounding, and Line Removal programs described above, which in turn directly reduce the likelihood of wildfire caused by an ignition from PG&E assets.

b. Forecast

Tables 7-13[57] and 7-14[58] provide the recorded and forecast amounts for the Integrated Planning Tool Development.

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57 See Exhibit (PG&E-4), WP 7-3, line 8.

58 See Exhibit (PG&E-4), WP 7-11, line 10.

TABLE 7-13
IPTD EXPENSES (MAT GEP)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	GEP	IPTD Expenses	–	–	–	–	$199	–	–	$180

	Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M059	Integrated Planning Undergrounding Tool Development (IPUTD)	Foundational

TABLE 7-14
IPTD CAPITAL (MAT 21#)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	21#	IPTD Capital	–	–	–	–	$2,906	–	–	$1,800	$1,620	$1,458	$1,166

	Risk Mitigation and Control Programs			
	MAT	Risk Program ID	Risk Program Name	CBR
2	21#	WLDFR-M059	Integrated Planning Undergrounding Tool Development (IPUTD)	Foundational

PG&E's IPTD capital and expense forecasts are based on the estimated staff time required to develop and maintain the IPTD tools.[59] The estimated time requirements were developed based on the time needed to complete prior projects of similar size and scope. While there is no current forecast for 2025 and 2026, we expect work to continue through this period, likely resulting in some incurred costs during that period.

PG&E's Information Technology (IT) organization employs an Agile project charging methodology for software development activities that allocates 90 percent of costs to capital and 10 percent to expense. PG&E's forecast assumes that there will be active software development activities (items 1 through 3 in the list immediately above) in 2027 and 2028. Starting in 2029, IPTD work will include both active software development and on-going operations and maintenance. Costs for operations and maintenance are generally recorded to expense.

Forecasts for this program are assumed to have escalation incorporated in the expense and capital totals.

D. Compliance

1. Deferred Work Analysis

The 2023 GRC Decision (OP 4) requires PG&E to continue following the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC.[60] The Deferred Work Settlement requires PG&E to include testimony on deferred work if the following criteria are met:

a) The work was requested and authorized based on representations that it was needed to provide safe and reliable service.

b) PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and

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59 Exhibit (PG&E-4), WP 7-3, line 8 and WP 7-10, line 10.

60 Pursuant to D.23-11-069, p. 900, OP 4, "Pacific Gas and Electric Company shall continue to follow the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC, subject to the limitations of Public Utilities Code Section 8386.3, which restricts the diversion of revenues authorized for certain wildfire mitigation activities."

c) PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.

For work covered in this Chapter, PG&E applied these criteria as explained in Analysis of "Deferred Work" discussion set forth in the Electric Distribution Forecast Summary and Investment Planning chapter.[61] This analysis is presented in the workpapers supporting that chapter.[62]

Based on this analysis, no work included in this Chapter was identified as "deferred work" under the terms of the Deferred Work Settlement.

2. 2023 GRC Decision

The 2023 GRC Decision (D.23-11-069) requires that PG&E comply with the following items:

a. System Hardening Risk Calculation

The 2023 GRC Decision required PG&E to submit an Advice Letter that explains the baseline methodology for calculating risk reduction of its system hardening work. Specific requirements are set forth in Ordering Paragraph 24. PG&E submitted Advice Letter 7150-E-A, which established PG&E's methodology for calculating baseline wildfire risk and forecasting risk reduction for projects included in the "hybrid" system hardening scenario for which the Commission approved cost recovery as part of PG&E's 2023 GRC. The Commission approved this Advice Letter on May 30, 2024. PG&E used this method to report on compliance with risk reduction targets in its Annual System Hardening Accountability Report (SHAR) ordered in the 2023 GRC Decision, Ordering Paragraphs 20-23.

b. System Hardening Accountability Report (SHAR)

The 2023 GRC Decision requires PG&E to submit an annual SHAR Advice Letter to show progress on the 2023 GRC every July 1 through the general rate case period. Specific requirements are set forth in Ordering Paragraphs 20, 21, 22, and 23. PG&E submitted its first

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61 Exhibit (PG&E-4), Ch. 2, Section E.1.b.

62 Exhibit (PG&E-4), WP 2-19.

annual SHAR on July 1, 2024 (AL 7312-E). The Safety Policy Division approved PG&E's SHAR on December 2, 2024.[63]

Table 1 of PG&E's July 1, 2024 SHAR shows that PG&E estimates it will exceed the required 18 percent risk reduction during the 2023-2026 period.

c. Undergrounding Cost Per Mile and Risk Reduction Due to Undergrounding

1) Undergrounding Costs and Risk Reduction 2021-2024

PG&E's 2023 GRC Decision, Ordering Paragraph 19 requires PG&E to provide the cost per mile and risk reduction it achieved in all undergrounding projects in the previous four years in its next general rate case, or other application seeking funding for undergrounding. Table 7-15 below shows the risk reduction and unit cost for undergrounding projects completed in the previous four years (2021-2024).

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63 Letter from Danjel Bout, Director, Safety Policy Division - Disposition Approving PG&E's Advice Letter regarding 2023 System Hardening Accountability Report, December 2, 2024. The December 2, 2024 disposition noted a purported error in PG&E's risk reduction calculation. PG&E met with the Safety Policy Division to discuss the issue and parties agreed to certain changes and clarifications that PG&E will make in subsequent SHAR submittals to address the issue (see PG&E's February 6, 2025 letter to Director Bout, "PG&E's System Hardening Accountability Report, Advice Letter 7312-E (Application 21-06-021).

TABLE 7-15
2023 GRC DECISION, OP 19 REQUIREMENT
ANNUAL UNIT COSTS ($M/MILE) AND RISK REDUCTION FOR UNDERGROUNDING

Line No.	Year	Undergrounding Unit Cost	Risk Reduction[(a), (b)]
1	2021	$2.3	0.03%
2	2022	$2.8	0.59%
3	2023	$3.0	1.74%
4	2024	$3.2	1.69%

(a) Risk Reduction values for 2021 and 2022 are based on WDRM V2.

(b) Risk Reduction for 2023 and 2024 is calculated based on the version of the risk model used to select the specific subproject, which was measured in accordance with Advice 7150-E-A, approved by the Commission on May 30, 2024.

2) Unit Cost Drivers

PG&E's 2023 GRC outlined a decreasing unit cost for undergrounding work as we gain experience and economies of scale over the 2023-2026 GRC period. This decreasing unit cost was anticipated as PG&E planned to continue developing innovations, tools and approaches to drive down unit cost over time.

Unit costs for undergrounding have decreased since program inception. In 2019, undergrounding cost more than $4 million per mile. As the program matured, for the 2023 GRC rate period to date (from 2023-2024), PG&E completed approximately 500 miles at an average unit cost of $3.1 million per mile, demonstrating an average unit cost lower than the 2023 target of $3.3 million per mile.[64]

In 2023, PG&E achieved a unit cost for undergrounding of $3.0 million per mile, beating the 2023 GRC target of $3.3 million per mile. While PG&E's unit cost went up in 2024 primarily due to the drivers outlined below, it is PG&E's intent to continue driving down undergrounding unit costs by implementing cost savings initiatives and identifying program efficiencies in 2025 and 2026. PG&E intends to meet four-year average annual unit cost of

64 D.23-11-069, p. 861, COL 79.

$2.97 million per mile that the Commission found reasonable in the 2023 GRC Decision[65] and is committed to meeting the $2.97 million per mile for undergrounding starting in 2027.[66]

Key drivers of unit cost increases include the presence of hard rock, challenging (i.e., steep) terrain, changes in restoration/paving requirements, and the need to provide temporary generation to customers during construction, particularly on Fire Rebuild projects. PG&E provides a brief example of how these issues impact undergrounding unit costs.

Temporary Generation

In an area where the Dixie fire damaged and destroyed approximately 4 miles of overhead distribution lines, PG&E provided temporary generation to approximately 2,200 customers for the duration of the rebuild project. PG&E operated between 8 and 12 trailer-sized primary generators at a substation where the transmission lines feeding the substation had been damaged in the fire. PG&E received its permit to begin construction in early fall 2022, but heavy snowfall shut down work from December through May the following year. During that time, PG&E was unable to relocate distribution lines underground and had to incur rental and fuel costs to operate the temporary generators to keep customers energized. Once work resumed in May, PG&E incurred significant overtime costs as construction crews worked as quickly as possible to restore permanent power to PG&E customers and end the temporary generation deployment. Other cost drivers included hard, rocky soil and having to bore under each culvert along a Caltrans highway. The unit cost for this subproject was $8.04 million per mile.

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65 D.23-11-069, p. 861, COL 79.

66 Starting in 2027, the unit cost will include the cost of transformers that were previously centralized within PG&E. Transformer costs are forecast to be approximately $55,000 per mile and therefore the total unit cost in 2027 is expected to be $3.03M/mile.

Challenging Terrain

As part of the Dixie fire rebuild, PG&E relocated approximately 4.2 miles of distribution lines underground along a highway. Due to the project location, PG&E was required to complete a Complex Utility Project Agreement (CUPA) to secure a Caltrans permit to complete the work. The CUPA established stringent requirements including:

1) Boring under every culvert. Boring under the culverts significantly slowed the construction process because PG&E encountered hard rock, narrow winding roads, and elevation changes in mountainous terrain;
2) Installing underground facilities in the center of the highway lane, as opposed to the shoulder, for most of the project so as not to impede Caltrans from installing a guard rail on the shoulder of the highway in areas with steep drop-offs. This alignment resulted in costly asphalt restoration, including repaving of the entire lane width; and
3) Providing additional oversight, including a third-party resident engineer and third-party inspector, and adhere to more stringent survey and mapping requirements. In several locations, PG&E could not use traditional construction methods for trenching and instead had to use other methods such as an excavator with a rock breaker attachment and bore machines specific for rock conditions to break through the hard rock. The additional time and more costly methods of installation required to complete the undergrounding work due to the hard rock and difficult terrain significantly increased construction costs. The unit cost for this project was $5.68 million per mile.

Hard Rock

PG&E planned a 2.16-mile undergrounding project and estimated that approximately 20 percent of the soil encountered during excavation would be hard rock. However, during excavation, crews encountered hard rock for almost the entire project. Based on analyzing similar projects, information from the contractor and

information collected during pre-construction walks, PG&E originally estimated it would excavate approximately 6,900 feet of material, whereas the actual excavation amounted to more than 36,000 feet of hard rock. PG&E planned to excavate at a rate of approximately 100 linear feet per day but was only able to excavate approximately 30 feet per day because of the presence of hard rock. The additional time needed to complete excavation also increased the time and cost for schedule-based activities, such as traffic control, inspectors, and construction management personnel. The unit cost for this project was $4.39 million per mile.

3) Cost Savings Opportunities

PG&E is developing multiple cost savings approaches to decrease undergrounding unit costs in the coming years. These approaches have been developed in response to the cost challenges experienced to date. However, achieving and maintaining unit cost decreases will depend on regulatory funding for enough undergrounding miles to sustain economies of scale. Macro-economic challenges such as higher than expected inflation and/or cost increases on construction supplies and materials due to tariffs would hinder PG&E's ability to reduce its unit costs. Regulatory certainty around PG&E's Undergrounding Plan is the key to establishing a sustainable supply chain for the duration of the undergrounding program. Certainty around the volume of undergrounding and funding of that work will allow PG&E to develop sustainable sourcing strategies by entering into long-term agreements with suppliers and manufacturers. Entering into long-term agreements will help PG&E to drive cost reductions over time. Examples of these cost savings opportunities are described below.

<u>Optimizing Design Standards and Tools</u>

PG&E is piloting a new design program called Automated Utility Design (AUD) that will allow project participants, such as internal and third-party designers and estimators, to design more efficiently and work collaboratively on project designs. Currently, PG&E and

its project partners use a variety of tools for creating and updating project documents. Using different tools is inefficient, leading to additional time to make changes and updates to project documents. AUD will allow for more efficient design creations, as well as improved collaboration across project teams. PG&E has also instituted new standards that give construction teams additional flexibility to optimize construction approaches to maximize productivity in the diverse environments where this undergrounding work is targeted.

Contract Pricing Approaches

PG&E is expanding its competitive lump sum pricing for projects. By moving from unit cost to lump sum contracting PG&E is enhancing the price competition on projects and transferring some cost risk from PG&E to the contractor. Currently, when contractors discover difficult or unexpected conditions on a unit cost project PG&E is responsible for additional costs through change orders to forecasted pricing. Under a lump sum contracting strategy, the contractors are responsible for examining the site and including the appropriate costs to address site conditions into its lump sum price which will limit or eliminate change orders based on site conditions.

Improving Soil/Spoils Management

PG&E is implementing programs to reduce costs related to spoils management. The Native Slurry Backfill (NSB) Program targets using native slurry backfill to reduce disposal costs and eliminate transportation costs. PG&E also identified an opportunity to enhance its soil mitigation plan by establishing mobile recycling yards. Mobile recycling yards will address issues related to locations and capacity for dumping at current yards and the cost for hauling to landfills. Enabling mobile recycling yards near project locations will allow for separating solids and liquids from drilling mud, using recycled drilling fluid for boring operations, and allowing projects with high volumes of drilling mud to use these yards.

d. Community Rebuild in the Town of Paradise and Surrounding Areas

The 2023 GRC Decision, OP 38 requires PG&E to submit a table in its 2027 GRC prepared testimony that reflects the same categories of information found in Application 21-06-021, Exhibit (PG&E-04), Workpaper Table 23-13. The table in the 2027 GRC must be updated to reflect updates (e.g., updated recorded costs for through 2024) to facilitate the Commission's review of Community Rebuild in the Town of Paradise and surrounding areas in its entirety.

PG&E is providing two cost tables as attachments to this testimony:

1) Attachment A is a table that reflects the same categories of information found in Application 21-06-021, Exhibit (PG&E-04), Workpaper Table 23-13. Attachment A shows the recorded and forecast costs for Community Rebuild work in the Town of Paradise. It has been updated to include recorded costs from 2018 through 2024. A copy of this table is also provided in the attachment associated with this chapter.[67]
2) Attachment B is a table that reflects the same categories of information found in Application 21-06-021, Exhibit (PG&E-04), Workpaper Table 23-13. Attachment B shows the recorded and forecast costs for Community Rebuild work in Greenville. PG&E is including the Greenville costs in Attachment B because, like the Community Rebuild work in Paradise, Greenville is the only other location where PG&E completed system hardening undergrounding that is both within the Dixie fire footprint and outside of the HFTD. Based on the definition of Community Rebuild in the 2023 GRC Decision (page 482), PG&E believes that the work completed in Greenville meets this definition and is therefore providing costs associated with this work in Attachment B. A copy of this table is also provided in the attachment associated with this chapter.[68]

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67 Exhibit (PG&E-4), Ch. 7, Attachment A: Updated for 2027 GRC: Butte Community Rebuild – 2023 GRC; Exhibit (PG&E-4), Chapter 23, Workpaper 23-13.

68 Exhibit (PG&E-4), Ch. 7, Attachment B: 2027 GRC Exhibit (PG&E-4), Chapter 7 – Other Community Rebuilds.

E. Accounts

1. Wildfire Mitigation Balancing Account

In the 2023 GRC Decision, the Commission directed PG&E to establish a one-way balancing account to record costs for wildfire mitigations.[69] In this rate case period, PG&E is proposing to retain the WMBA as requested in Exhibit (PG&E-4), Chapter 4 Section E. PG&E summarizes its request to retain, modify, or discontinue existing cost recovery mechanisms as described in this exhibit and associated revenue requirements in Exhibit (PG&E-10), "Results of Operations," Chapter 16 "Balancing Accounts."

PG&E proposes that the costs for the wildfire mitigations in this chapter be recorded to the Wildfire Mitigation Balancing Account (WMBA). A summary of PG&E's total WMBA request is in Exhibit (PG&E-4), Chapter 4 Section E.

2. Annual Extension Authorization for Undergrounding

PG&E also requests authorization to include additional Annual Extensions for undergrounding, as necessary, until PG&E's EUP is approved,[70] through the Annual Electric True-Up (AET) advice letter process or another Tier 2 rate change advice letter. PG&E proposes that if the EUP is not approved by September 1 in any future year, PG&E is authorized to extend funding for undergrounding through the Tier 2 Annual Electric True-Up Advice Letter or another Tier 2 rate change advice letter for inclusion in rates in the following year. PG&E is proposing 400 underground miles for 2028 and for all subsequent years, as needed, until PG&E transitions to the EUP. The proposed 400 miles forecast aligns to the 395 undergrounding miles estimated in PG&E's 2024 RAMP[71] and to PG&E's 2026-2028 Base WMP undergrounding miles target (Target GH-04) of 400 miles. PG&E's forecast is $1,212 million in funding in 2028 at an

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69 See D.23-11-069, p. 910, OP 39, Section 4.24 Electric Distribution Ratemaking.

70 PG&E intends to file an EUP after all EUP Guidelines are adopted by Energy Safety and the CPUC.

71 Application (A.) 24-05-008, Exhibit (PG&E-4), p. 1-89, Table 1-24, line 4.

average unit cost of $3.03 million per mile ($2.97 million per mile plus $55,000 per mile for transformers).

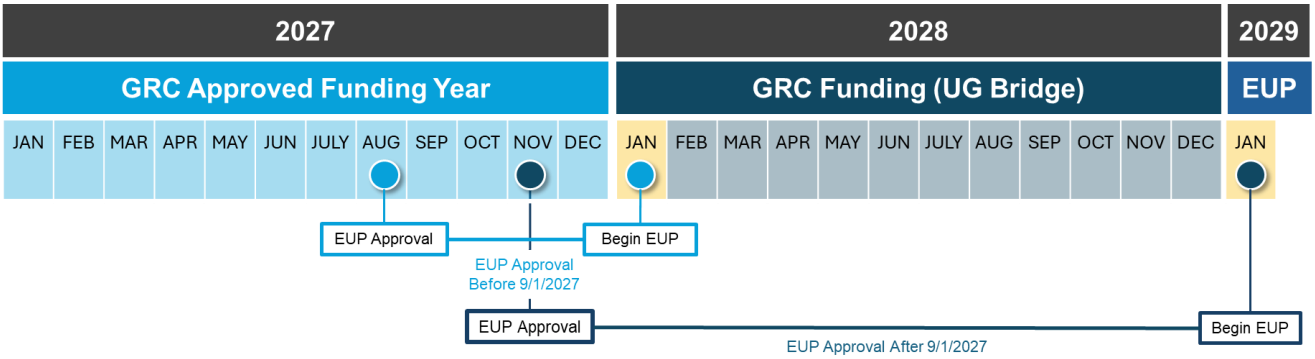
PG&E's request to extend funding via the AET or a Tier 2 rate change advice letter if EUP approval is not obtained by September 1 is because PG&E needs at least four months (from September 1 to January 1) to make adjustments to our undergrounding workplans and processes to fully incorporate any EUP requirements. The requirements for undergrounding work funded by the EUP are different than the requirements for undergrounding funded in the GRC. If EUP approval occurs after September 1, PG&E will not have adequate time to update its undergrounding plans in time for EUP cost recovery to begin starting on January 1, resulting in a funding gap.

Table 7-16 and Figure 7-6 below show PG&E's proposed schedule for transitioning from the GRC to the EUP under various EUP approval scenarios. PG&E's strong preference is to receive EUP approval by August 31, 2027 and therefore not need to exercise this Annual Extension process. However, as discussed in Section B.1, program continuity is necessary to sustain program efficiencies and execute critical wildfire safety work that keep our communities safe.

TABLE 7-16
RECURRING ANNUAL APPROVAL OF PG&E'S UNDERGROUNDING PROGRAM

Line No.	2023-2026 GRC Undergrounding Program Continuation	GRC Underground Program Funding Year	EUP Approval	EUP Start
1	Year 1 GRC Request	2027	By August 31, 2027	January 1, 2028
2	Year 2 Continuation	2028	September 1, 2027 – August 31, 2028	January 1, 2029
3	Year 3 Continuation	2029	September 1, 2028 – August 31, 2029	January 1, 2030
4	Year 4 Continuation	2030	After August 31, 2029	January 1, 2031

FIGURE 7-6
ILLUSTRATIVE EXAMPLE – TRANSITIONING FROM THE GRC TO THE EUP WITH UG BRIDGE PROGRAM FUNDING



3. Mechanism for Updating Overhead Hardening Funding Forecasts

The focus of PG&E's system hardening program is to reduce ignition and outage program risk in the HFTD/HFRA through a combination of undergrounding, overhead hardening and line removal. For this GRC period, risk reduction will be achieved through overhead hardening and line removal work funded in the GRC, and undergrounding work funded in both the GRC and EUP.

PG&E requires flexibility in the number of miles that will be authorized to overhead harden during this GRC period because of the transition from the GRC to the EUP. At this time, the number of undergrounding miles that will be funded in the EUP during the GRC period is unknown because: (1) the start date of the EUP is unknown; (2) the number of undergrounding miles that will be authorized by Energy Safety and the Commission in the EUP is unknown; and (3) the amount of undergrounding miles authorized for cost recovery by the Commission in the EUP proceeding is unknown. If the EUP is delayed and/or the number of undergrounding miles authorized or the approved funding is less than PG&E's estimate to achieve its target risk reduction, there will be a gap between PG&E's targeted risk reduction and the risk reduction it can achieve based on the underground miles and/or funding approved.

If the Commission or Energy Safety do not approve PG&E's full forecast for undergrounding in the EUP, PG&E would then look to establish an adjustment mechanism via an appropriate regulatory procedure to reduce the equivalent risk on the system via additional overhead hardening.

F. Conclusion

Based on the demonstration above and on the evidence presented in the associated attachments and workpapers to this chapter, PG&E respectfully requests that the Commission:

1) Adopt the expense forecasts in Section A.2, Table 7-1;
2) Adopt the capital forecasts in Section A.2, Table 7-2;
3) Approve PG&E's proposal for its Undergrounding Bridge Program for 2027 as described in Section C.2;
4) Provide a directive that PG&E has authorization to extend funding for undergrounding beyond 2027 if PG&E's Electric Undergrounding Plan (EUP) is not approved by September 1 each year (beginning September 1, 2027) through the Tier 2 Annual Electric True-up Advice Letter or another Tier 2 rate change advice letter for inclusion in rates in the following year, as shown in Section E.2, Table 7-16;
5) Adopt the specific post Test-Year attrition proposed for the Undergrounding Program as described in Section C.2; and
6) Consider the adjustment mechanism proposal in this GRC, if an adjustment mechanism is needed to authorize additional overhead hardening in the GRC based on the undergrounding mileage approved in the EUP. See Section E.3. for further information.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

ATTACHMENT A

UPDATED FOR 2027 GRC: BUTTE COMMUNITY REBUILD, 2023 GRC EXHIBIT (PG&E-4), CHAPTER 23 WORKPAPER 23-13

Attachment A

Pacific Gas and Electric Company
Updated for 2027 GRC
Butte Community Rebuild
2023 GRC Exhibit 4, Chapter 23, Workpaper 23-13
(Thousands of Nominal Dollars)

Line No.	Chapter 3 - Electric Operations	MAT/MWC	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded
1	**Expense**		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
2	Electric Service Connections	**IFF**	($44)	$0	$156	$0	$0	$0	$0
3	Construction Site Clearing	**IF#, IFA, IFB, IFF**	$144,585	$231,744	$23,844	$3,624	($1,814)	$1,073	$1,766
4	Community Rebuild Program Management Office	**IFF**	$0	$1,549	$5,212	$2,571	($224)	$911	($1,070)
5	Telecom Pole Removal	**IFA**	$0	$0	$0	$0	$177	$23	$5
6	**Total Expense**		**$144,541**	**$233,292**	**$29,211**	**$6,195**	**($1,861)**	**$2,007**	**$702**
7	**Capital**		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
8	Electric Underground Construction Hardening Program	**08W**	$0	$16,816	$24,634	$38,816	$82,486	$98,563	$109,671
9	Electric Underground Mainline Construction	**95F**	$0	$21,486	$39,939	$59,713	$68,981	$87,739	$39,853
10	Electric Overhead Mainline Construction	**95F**	$0	$16,980	$16,899	$812	$211	$384	($160)
11	Electric Service Connections	**95A, 95B, 95F**	$0	$8,037	$18,543	$24,852	$18,687	$14,885	$12,310
12	Remote Grids	**95F**	$0	$0	$0	$0	$0	$0	$0
13	Electric Mobile Home Parks	**95F**	$0	$1,619	$7,544	$7,312	$2,862	$1,163	($29)
14	Community Rebuild Program Management Office	**95F**	$0	$0	$5,283	($2,310)	$0	$0	$0
15	**Total Capital**		**$0**	**$64,938**	**$112,842**	**$129,195**	**$173,227**	**$202,734**	**$161,646**
16	**Exhibit (PG&E-4) Electric Operations - Total Costs**		**$144,541**	**$298,231**	**$142,054**	**$135,389**	**$171,366**	**$204,741**	**$162,347**

	Chapter 3 - Gas Operations		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded
17	**Expense**		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
18	Gas Main Construction	**LXA**		$5,554	($4,245)				$0
19	Gas Services	**LXA, FIM**		$71	$8,454	$2,698	($641)	$104	$475
20	Community Rebuild Program Management Office	**LX**	$0	$1,355	$930	$644	$21	$134	($16)
21	**Total Expense**		**$0**	**$6,981**	**$5,139**	**$3,342**	**($621)**	**$238**	**$459**
22	**Capital**		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
23	Aldyl-A Gas Mainline Construction	**14D**	$0	$14,379	$27,663	$20,836	$31,694	$7,188	$1,366
24	Gas Main Construction	**3QA, 50A**	$1	($2)	$3,226	$5,023	$9,742	$10,594	$7,916
25	Gas Services	**3QA, 50B**	$0	$755	$8,851	$15,819	$21,407	$21,268	$6,245
26	Gas Mobile Home Parks	**3QA, 50A**	$0	$1,146	$5,762	$2,791	$1,589	$903	$182
27	**Total Capital**		**$1**	**$16,279**	**$45,502**	**$44,469**	**$64,432**	**$39,954**	**$15,709**
28	**Exhibit (PG&E-3) Gas Operations - Total Costs**		**$1**	**$23,260**	**$50,641**	**$47,811**	**$63,812**	**$40,192**	**$16,168**

	Chapter 3 - Customer Care		Recorded	Recorded	Recorded	Recorded	Recorded	Recorded	Recorded
29	**Expense**		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
30	Customer Care	**IG#**	$0	$37	$39	$4	$0	$0	$0
31	**Total Expense**		**$0**	**$37**	**$39**	**$4**	**$0**	**$0**	**$0**
32	**Capital**		**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
33	Nov 2018 Camp Fire-Electric Meters-CEMA	**3M**	$0	$26	$6	$0	$0	$355	$0
34	Nov 2018 Camp Fire-Gas Meters-CEMA	**3M**	$0	$47	$37	$0	$0	$392	$0
35	Nov 2018 Camp Fire-Gas Modules-CEMA	**3M**	$0	$0	$30	$0	$0	$0	$0
36	Butte Wildfire Rebuild - Electric Meters	**25**	$0	$0	$0	$0	$0	$0	$0
37	Butte Wildfire Rebuild-Gas Mtrs/Modules	**74**	$0	$0	$0	$0	$0	$0	$0
38	**Total Capital**		**$0**	**$74**	**$73**	**$0**	**$0**	**$747**	**$0**
39	**Exhibit (PG&E-6) Customer Care - Total Costs**		**$0**	**$111**	**$111**	**$4**	**$0**	**$747**	**$0**
40	**Total Expense (PG&E-3, PG&E-4, PG&E-6)**		**$144,541**	**$240,310**	**$34,389**	**$9,541**	**($2,481)**	**$2,245**	**$1,161**
41	**Total Capital (PG&E-3, PG&E-4, PG&E-6)**		**$1**	**$81,291**	**$158,417**	**$173,664**	**$237,660**	**$243,434**	**$177,354**
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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 7

ATTACHMENT B

OTHER COMMUNITY REBUILDS:

TOTAL COSTS BY WORKSTREAM

Attachment B

Pacific Gas and Electric Company
2027 GRC Exhibit (PG&E-4), Chapter 7 - Other Community Rebuilds
Total Costs by Workstream
(Thousands of Nominal Dollars)

Line No.	Electric Operations	MAT/MWC	Recorded	Recorded	Recorded	Recorded
1	**Expense**		**2021**	**2022**	**2023**	**2024**
2	Electric Service Connections	**IFF**	-	-	-	-
3	Construction Site Clearing	**IFF**	-	-	-	-
4	Community Rebuild Program Management Office	**IFF**	-	-	-	-
5						
6	**Total Expense**		**-**	**$0**	**$0**	**$0**
7	**Capital**		**2021**	**2022**	**2023**	**2024**
8	Electric Underground Construction Hardening Program	**08W**	-	-	-	-
9	Electric Underground Mainline Construction	**95F**	-	2,687,026	10,446,252	16,548,617
10	Electric Overhead Mainline Construction	**95F**	-	-	-	-
11	Electric Service Connections	**95F**	1,136	748,662	804,698	768,260
12	Remote Grids	**95F**	-	-	-	-
13	Electric Mobile Home Parks	**95F**	-	15,415	72,762	550,456
14	Community Rebuild Program Management Office	**95F**	-	-	-	-
15	**Total Capital**		1,136	3,451,104	11,323,712	17,867,333
16	**Exhibit (PG&E-4) Electric Operations - Total Costs**		**1,136**	**$3,451,104**	**$11,323,712**	**$17,867,333**
17	**Exhibit (PG&E-3) Gas Operations**		**Recorded**	**Recorded**	**Recorded**	**Recorded**
18	**Expense**		**2021**	**2022**	**2023**	**2024**
19	Gas Main Construction	**LX**	-	-	-	-
20	Gas Services	**LX, FIM**	-	-	-	-
21	Community Rebuild Program Management Office	**LX**	-	-	-	-
22	**Total Expense**		$0	$0	$0	$0
23	**Capital**		**2021**	**2022**	**2023**	**2024**
24	Aldyl-A Gas Mainline Construction	**14D**	-	-	-	-
25	Gas Main Construction	**3QA**	-	-	-	-
26	Gas Services	**3QA, 50A**	-	-	-	-
27	Gas Mobile Home Parks	**3QA, 50B**	-	-	-	-
28	**Total Capital**		$0	$0	$0	$0
29	**Exhibit (PG&E-3) Gas Operations - Total Costs**					
30	**Exhibit (PG&E-6) Customer Care**		**Recorded**	**Recorded**	**Recorded**	**Recorded**
31	**Expense**		**2021**	**2022**	**2023**	**2024**
32	Customer Care		-	-	-	-
33	**Total Expense**		$0	$0	$0	$0
34	**Capital**		**2021**	**2022**	**2023**	**2024**
35	Nov 2018 Camp Fire-Electric Meters-CEMA	**3M**	-	-	-	-
36	Nov 2018 Camp Fire-Gas Meters-CEMA	**3M**	-	-	-	-
37	Nov 2018 Camp Fire-Gas Modules-CEMA	**3M**	-	-	-	-
38	Butte Wildfire Rebuild - Electric Meters	**25**	-	-	-	-
39	Butte Wildfire Rebuild-Gas Mtrs/Modules	**74**	-	-	-	-
40	**Total Capital**		$0	$0	$0	$0
41	**Exhibit (PG&E-6) Customer Care - Total Costs**					
42	**Total Expense (PG&E-3, PG&E-4, PG&E-6)**		**$0**	**$0**	**$0**	**$0**
43	**Total Capital (PG&E-3, PG&E-4, PG&E-6)**		**$1,136**	**$3,451,104**	**$11,323,712**	**$17,867,333**

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 8

VEGETATION MANAGEMENT

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
VEGETATION MANAGEMENT

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 8
VEGETATION MANAGEMENT

A. Introduction and Summary

1. Overview

The purpose of this chapter is to demonstrate that Pacific Gas and Electric Company's (PG&E or the Company) expense forecasts to operate its Electric Distribution Vegetation Management (VM) Program are reasonable and should be approved.

PG&E's forecast is organized into three categories of work:

1) Routine Vegetation Management;
2) Hazard Patrol; and
3) Wildfire Mitigation Activities.

PG&E's forecast also includes costs for Supporting Activities, which provide centralized support across all work categories. These activities encompass safety, quality, public education, environmental review, customer relations, program management, construction management, document governance, constraints management, data and technology, vegetation asset strategy and analytics, and operational analytics.

PG&E's Vegetation Management work activities fulfill regulatory requirements to: (1) perform vegetation inspections to reduce the likelihood of ignitions, (2) remove vegetation hazards, which may contact or fall on conductors, (3) maintain clearance between vegetation and conductors, and (4) create firebreak clearances at the base of poles with subject equipment.

Most of the work discussed in this chapter serves as controls or mitigations to reduce the risk of wildfire associated with Electric Distribution overhead assets (WLDFR) and the risk of failure of distribution overhead assets or operational functionality (DOVHD). These Electric Distribution Vegetation Management activities are critical to our efforts to prevent trees and other vegetation from growing or falling into electrical facilities. They ensure the safe, reliable, and continuous operation of the electrical system.

Each Electric Distribution Vegetation Management program is summarized below.

a. Routine Vegetation Management

PG&E's Routine Regulatory Compliance Routine/Annual Patrol supports: (1) compliance with the Vegetation Management standards established by the California Public Utility Commission's (CPUC or Commission) General Order (GO) 95 Rule 35,[1] (2) compliance with Public Resources Code (PRC) 4293,[2] and (3) the implementation of PG&E's Wildfire Mitigation Plan (WMP).[3] This work involves annual patrols of vegetation in proximity to PG&E's overhead Electric Distribution lines and the resulting prescribed tree work.

As part of the Routine Vegetation Management program, PG&E's Vegetation Control program also supports compliance with PRC 4292[4] and the implementation of PG&E's WMP[5] by performing year-round pole clearing activities to remove and clear vegetation around Electric Distribution poles to maintain firebreaks. Routine Vegetation Management activities support public safety, reliability, maintenance, and regulatory compliance.

b. Hazard Patrol

PG&E's Hazard Patrol program, previously referred to as Second Patrol or the Tree Mortality program, is offset by approximately six months from the Annual/Routine Patrol conducted under the Routine Vegetation Management program in high-risk areas. This program addresses mid-cycle changes in conditions. Hazard Patrol supports

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1 General Order 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances. The rule provides that the minimum clearances, measured between line conductors and vegetation under normal conditions, shall be maintained.

2 PRC § 4293 imposes standards for fire protection areas, required clearance according to voltage, cutting or trimming of decayed trees, and permitting exceptions.

3 PG&E 2026-2028 Wildfire Mitigation Plan, Section 9.2.1 (Apr. 4, 2025).

4 PRC §4292 imposes standards for firebreak clearances around poles or towers that support certain equipment.

5 PG&E 2026-2028 Wildfire Mitigation Plan, Section 9.2.1 (Apr. 4, 2025).

compliance with the CPUC's GO 95,[6] Rule 35, PRC 4293,[7] CPUC Resolution ESRB-4 (June 12, 2014),[8] and the implementation of PG&E's WMP.[9] CPUC Resolution ESRB-4 requires utilities to increase vegetation inspections to reduce the likelihood of fires. Both GO 95, Rule 35 and PRC 4293 requires utilities to remove dead, rotten, or diseased portions of healthy trees that may fall into overhead powerlines. Hazard Patrol activities address public safety, reliability, maintenance, and regulatory compliance.

c. Wildfire Mitigation Activities

PG&E's Vegetation Management Wildfire Mitigation activities address wildfire mitigation risk associated with vegetation.[10] The activities to mitigate this risk, which are described in more detail below, include the following:

- Targeted Inspection (previously Focused Tree Inspection): Is a data-informed and risk-model prioritized approach to identify and mitigate vegetation-related wildfire risk in high-risk areas.

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6 General Order 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances.

7 PRC § 4293 imposes standards for fire protection areas, required clearance according to voltage, cutting or trimming of decayed trees, and permitting exceptions.

8 See Resolution ESRB-4 (Issued June 16, 2014) p.14 OP 2 ("Investor Owned Electric Utilities must take practicable measures necessary to reduce the likelihood of fires associated with their facilities. These measures include: increasing vegetation inspections and removing hazardous, dead, and sick trees, and other vegetation near the Investor-Owned Utility (IOU) electric power lines and poles; sharing resources with the California Department of Forestry and Fire Protection (CAL FIRE) to staff lookouts adjacent to the IOUs' property; and clearing access roads under power lines for fire truck access.").

9 PG&E 2026-2028 Wildfire Mitigation Plan (Apr. 4, 2025).

10 Vegetation Management's Wildfire Mitigation Activities presented in this chapter refer to the portfolio of VM mitigation activities and initiatives focused on wildfire risk reduction in high-risk areas, managed by the Vegetation Management organization and recorded to the Vegetation Management Balancing Account (VMBA). These VM Wildfire Mitigation Activities are separate from those wildfire risk mitigation programs and activities managed by PG&E's Wildfire Strategy and Operational Support Organization *and* recorded to the Wildfire Mitigation Balancing Account (WMBA). See Exhibit (PG&E-4) Ch 4 Wildfire Mitigation Summary and Strategy.

- Tree Removal Inventory: Addresses trees that PG&E identified for mitigation during the legacy Enhanced Vegetation Management program, which PG&E could not work due to permitting, environmental, or other constraints. In this activity, Circuit Protection Zones are prioritized using the Wildfire Distribution Risk Model.
- Vegetation Management for Operational Mitigations: Consists of targeted inspection and tree mitigation activities based upon weather-driven events triggered by the Enhanced Powerline Safety Settings (EPSS) program. Similar activities may be triggered by our Public Safety Power Shutoff (PSPS) Program.
- Utility Defensible Space: Reduces vegetative fuels under and adjacent to Electric Distribution facilities located in CPUC-designated High Fire Threat Districts (HFTD) and High Fire Risk Areas (HFRAs).
- Vegetation Control - Right-of-Way Clearing: Is risk-informed pole clearing. PG&E maintains additional firebreaks at non-State Responsibility and non-Federal Responsibility Area poles in HFTDs/HFRAs to comply with PUC 8386,[11] which requires PG&E's WMP to include Vegetation Management activities to enhance system safety, reliability, and resilience.

PG&E's wildfire mitigation activities implement strategies to reduce vegetation caused wildfires in high-risk areas, address previously identified trees, and reduce vegetation fuels to maintain firebreaks in HFTDs/HFRAs.

d. Supporting Activities

PG&E's Vegetation Management Supporting Activities provide support for PG&E's Vegetation Management work in the areas of strategy and analytics, data and technology, safety, quality management, constraints management, program management,

[11] Pub. Util. Code § 8386 (c)(3) "A description of the preventive strategies and programs to be adopted by the electrical corporation to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risks."

construction management, and document governance (i.e., standards and procedures) and training.

2. Summary of Request

PG&E requests that the Commission:

- Adopt the expense forecasts in Section A.2, Table 8-1;
- Adopt the specific post Test-Year attrition proposed for the Vegetation Management activities forecasted in MWC HN;
- Approve the continuation of the one-way Vegetation Management Balancing Account (VMBA) to track and record expenses for PG&E's Electric Distribution Vegetation Management activities discussed herein; and
- Authorize PG&E to record capital expenditures to the VMBA for technology software and/or hardware, which may include but are not limited to tree tagging and tree tag registry, work scheduling optimization, and mobile device licensing, beginning in 2027.

Forecasts in this chapter are shown with no escalation included in all expense totals. PG&E will offset escalation through work execution efficiencies to improve affordability.

TABLE 8-1
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

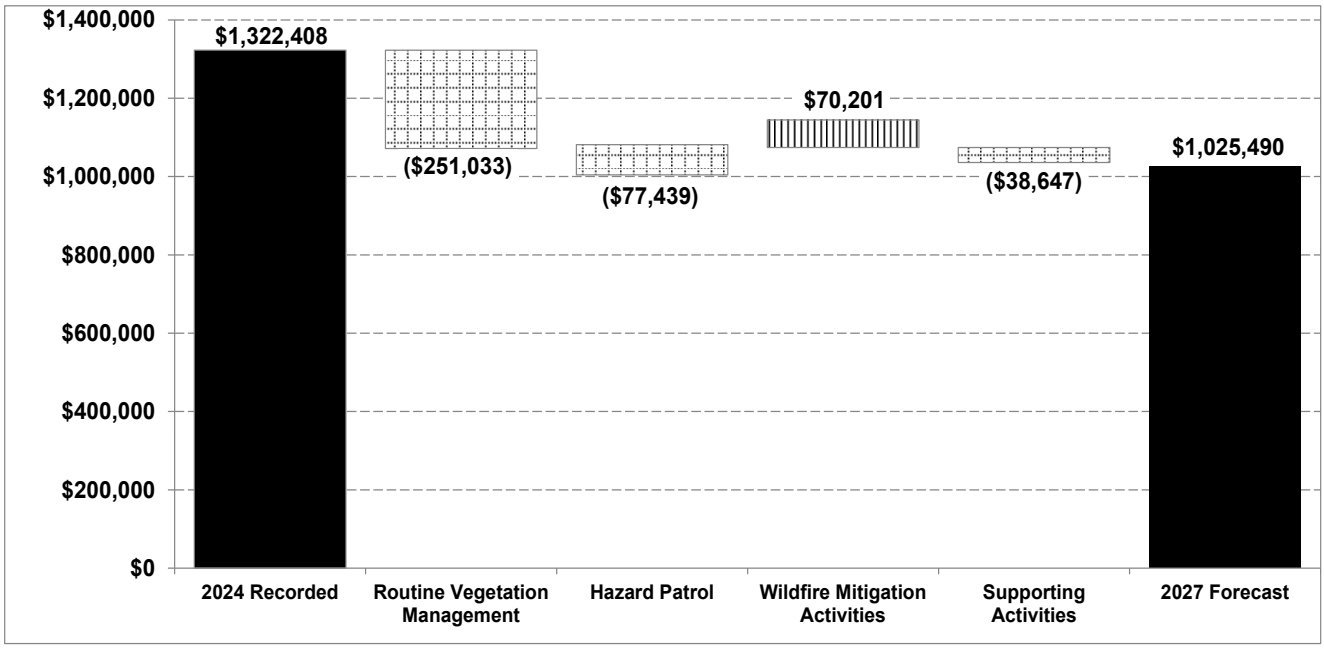
Line No.	MWC	Description	Category	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	Workpaper Reference
1	HN	E Dist Tree Trim Bal Acct	Routine Vegetation Management	$684,711	$596,413	$597,198	$698,891	$815,783	$637,755	$630,863	$564,750	WP 8-3
2			Wildfire Mitigation Activities	–	3,562	24,899	5,176	39,783	–	–	5,544	WP 8-3
3			Supporting Activities	44,665	86,585	99,675	158,812	147,433	$220,225	$217,132	154,684	WP 8-4
4	IG	Manage Var Bal Acct Processes	Hazard Patrol	86,752	81,825	110,682	119,388	123,496	107,118	106,192	46,058	WP 8-3
5			Wildfire Mitigation Activities	116,974	85,641	192,110	96,752	119,825	233,907	231,006	224,266	WP 8-3
6			Supporting Activities	314,245	685,957	605,808	74,421	76,087	58,806	58,257	30,188	WP 8-5, WP 8-6
7		Routine Vegetation Management Total		$684,711	$596,413	$597,198	$698,891	$815,783	$637,755	$630,863	$564,750	
8		Hazard Patrol Total		$86,752	$81,825	$110,682	$119,388	$123,496	$107,118	$106,192	$46,058	
9		Wildfire Mitigation Activities Total		$116,974	$89,203	$217,009	$101,928	$159,609	$233,907	$231,006	$229,810	
10		Supporting Activities Total		$358,910	$772,541	$705,483	$233,233	$223,520	$279,030	$275,389	$184,872	
11		Grand Total		$1,247,347	$1,539,982	$1,630,372	$1,153,440	$1,322,408	$1,257,810	$1,243,450	$1,025,490	WP 8-3

Note: The values reflected in this table may vary from the initial Results of Operations (RO) Model provided with PG&E's GRC filing due to timing differences. The RO Model will be updated to incorporate these errata in a future submission.

a. Expense

Figure 8-1 provides an expense walk identifying key drivers for the difference in the 2027 forecast compared to 2024 recorded costs. Each driver is summarized below.

FIGURE 8-1
EXPENSE WALK 2024-2027
(THOUSANDS OF NOMINAL DOLLARS)



The key drivers of the 2027 expense forecast are*:*

- A decrease to Routine Vegetation Management costs compared to 2024 actual costs due to a lower volume of trees forecasted for work. The lower forecast assumes undergrounding work and historical tree removals is expected to result in a lower tree population that could grow or fall into overhead facilities.[12]
- A decrease to Hazard Patrol costs compared to 2024 actual costs due to undergrounding work and fewer HFTD and HFRA miles expected to be inspected. See Section B.2.a, Hazard Patrol

12 Exhibit (PG&E-4), WP 8-7.

overview, for a description of PG&E's revised mileage inspection approach.[13]

- An increase to Wildfire Mitigation Activities costs compared to 2024 actual costs due to a higher volume of trees forecasted for work by Targeted Inspection[14] and Tree Removal Inventory,[15] and an increase in Wood Management costs due to debris created by this additional tree work.[16]
- A decrease to Supporting Activities as compared to 2024 actual costs, driven by decreases in Program Management and Constraints Management costs as described in Section B.4.

As noted previously, the forecasts in this chapter are shown with no escalation included in all expense totals. PG&E presents a reduced Vegetation Management forecast in the 2027 GRC, primarily driven by operational efficiencies, such as incorporating VM activities into Routine and/or Hazard patrols, tree removal assumptions, and the impact of PG&E's undergrounding activities. PG&E expects overall Vegetation Management costs to decrease year-over-year through the end of the 2027 GRC period, which will offset escalation and improve affordability.

b. Specific Post Test-Year Attrition Request

PG&E is forecasting a year-over-year decrease in expense in MWC HN through the end of this rate case period, primarily driven by operational efficiencies such as: incorporating vegetation management activities into routine and/or hazard patrols, tree removal, and undergrounding. As such, the simple escalation described in Exhibit (PG&E-11) in the attrition years (2028-2030) is not appropriate. PG&E requests that each attrition year for MWC HN be separately authorized in the GRC and that the cost basis of the attrition years not be based on

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13 Exhibit (PG&E-4), WP 8-9.

14 Exhibit (PG&E-4), WP 8-10.

15 Exhibit (PG&E-4), WP 8-11.

16 Exhibit (PG&E-4), WP 8-14.

just the 2027 test year with simple escalation factors.[17] Table 8-2 shows the forecast for MWC HN through 2030.

TABLE 8-2
MWC HN 2027-2030 FORECAST
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Workpaper Reference
1	HN	Routine VM	$564,750	$557,377	$550,924	$544,542	WP 8-3, line 2
2	HN	Wildfire Mitigation Activities	5,544	5,544	5,544	5,544	WP 8-6, line 6
3	HN	Support Activities	154,684	153,249	151,993	150,751	WP 8-6, line 6
4		Total	$724,979	$716,170	$708,461	$700,837	

The main drivers of the decreases in years 2028-2030 are lower tree work volumes due to undergrounding work and historical tree removals. PG&E describes the specific activities that drive these forecast changes in the sections below and in the corresponding workpapers.[18]

3. Risks Addressed

PG&E's forecast for Vegetation Management addresses the Electric Distribution-related Risks described in Table 8-3.[19] For each program or activity forecast in this chapter that serves as a risk control or risk mitigation, PG&E identifies the risk addressed, the cost-benefit ratio (CBRs) when applicable, and describes why the risk mitigation and control work is necessary and justified in the activities' Forecasts in Section B below. A summary table of the foundational activities and risk control or mitigation programs forecast in this chapter, their program names, identification, and CBRs, when applicable, is presented in Table 8-4 below.

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17 Attrition adjustment policies and mechanics, including discrete expense and capital programs, are addressed in Exhibit (PG&E 11), Chs. 1, 2, and 3.

18 Exhibit (PG&E-4), WP 8-8.

19 For additional information about these risks, see Exhibit (PG&E-4), Ch. 3.

TABLE 8-3
RISKS ADDRESSED BY VEGETATION MANAGEMENT ACTIVITIES

Line No.	Risk Name	Risk ID	Risk Description
1	Wildfire with PSPS and EPSS	WLDFR, WPSPS, WEPSS	The Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands, or the environment originating from PG&E assets or activities. In the near term, due to the use of Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS), we have also defined Post PSPS/EPSS Wildfire Risk as Wildfire Risk with PSPS and EPSS. This risk accounts for the benefits and consequences of operational mitigations such as PSPS and EPSS.
2	Failure of Electric Distribution Overhead Assets	DOVHD	This risk is defined as a lack of remote operational functionality that may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.
3	Public Contact with Intact Energized Electric Equipment	PCEEE	This risk is defined as the risk of reportable serious injury or fatality to a third-party contractor or member of the public from an interaction with intact PG&E electric assets that did not originate from asset failure.

TABLE 8-4
FOUNDATIONAL ACTIVITIES, RISK MITIGATIONS AND RISK CONTROL PROGRAMS

Line No.	MAT	Program Name	Risk Program ID(s)	CBR (2027-2030)
1	Risk Mitigations			
2	IGJ	VM Distribution – Targeted Inspection	DOVHD-M028, WLDFR-M028	6.5
3	IGJ	VM Distribution – Tree Removal Inventory	DOVHD-M030, WLDFR-M030	3.9
4	IGJ	VM for Operational Mitigations (VMOM)	DOVHD-M029, WLDFR-M029	12.9
5	IGJ	Utility Defensible Space – Distribution	WLDFR-M041	2.7
6	HNA	Vegetation Control/Right-of-Way Clearing	DOVHD-M027, WLDFR-M027	4.0
7	Risk Controls			
8	HNA	VM Distribution – Routine Patrols	DOVHD-C001, WLDFR-C001	2.4
9	HNA	Pole Clearing – Routine	DOVHD-C025, WLDFR-C080	2.0
10	IGI	VM Distribution – Second Patrols	DOVHD-C002, WLDFR-C002	3.1
11	HN#	Public Safety Awareness	DOVHD-C024, PCEEE-C002, DUNGD C017	27.2
12	Foundational Activities			
13	HN#	Vegetation Management Data and Technology – Distribution	WLDFR-C077	Foundational
14	HN#, IGI	Vegetation Management Document Governance (Standards, Procedures) and Training	WLDFR-C081	Foundational
15	HN#	VM Support – Routine Patrol	WLDFR-C082	Foundational
16	HNA	VM Wood Management – Routine Patrol	WLDFR-C083	Foundational
17	IGI	VM Support – Second Patrol	WLDFR-C084	Foundational
18	IGI	VM Wood Management – Second Patrol	WLDFR-C085	Foundational
19	IGJ	VM Support – Mitigations	WLDFR-M047	Foundational
20	IGJ	VM Wood Management – Mitigations	WLDFR-M048	Foundational

This chapter contains wildfire mitigations and/or controls which contribute to climate resilience because they address wildfire risk. For more

information about the relationship between this General Rate Case filing and PG&E's climate resilience plans, see Exhibit (PG&E-2), Chapter 1.

B. Vegetation Management Forecast

1. Routine Vegetation Management (MATs HNA, HN#)

PG&E's Routine Vegetation Management forecast includes the following components, which are described in more detail below.

- Routine Regulatory Compliance work (Annual/Routine Patrol) supports compliance with the CPUC's GO 95,[20] Rule 35 and PRC 4293,[21] through annual patrols of vegetation in proximity to PG&E's overhead Electric Distribution facilities and the prescribed resulting tree work (described in Section B).
- The Vegetation Control program performs year-round pole clearing activities to support compliance with PRC 4292[22] and PG&E's WMP.[23] Pole clearing involves the removal or clearing of vegetation around subject distribution poles to maintain firebreaks.
- Wood Management addresses wood material resulting from Vegetation Management work.
- The Routine Vegetation Management forecast also includes support activities as described in Subsection 4 below.

a. Annual Patrol (MAT HNA)

1) Overview

PG&E's Annual/Routine Patrol is a yearly patrol of vegetation in proximity to approximately 80,000 miles of PG&E owned electric overhead primary lines, and PG&E's secondary distribution lines, to

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20 GO 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances.

21 PRC § 4293. Fire protection areas; Required clearance according to voltage; Cutting or trimming decayed trees; Permitting exceptions.

22 Cal. Code Regs. tit. 14, § 1253, Time When PRC 4292-4296 Apply:
"The minimum firebreak and clearance provisions of PRC 4292-4296 are applicable during the declared California Department of Forestry and Fire Protection fire season for a respective county."

23 PG&E 2026-2028 Wildfire Mitigation Plan, Section 9.4 (Apr. 4, 2025).

comply with GO 95, Rule 35,[24] PRC 4293,[25] PG&E's WMP,[26] and to address risks identified in PG&E's Risk Assessment Mitigation Phase (RAMP) Report. The total overhead miles fluctuate as overhead miles decrease due to undergrounding and new construction may add miles.

During annual patrol of these Electric Distribution assets, Vegetation Management Inspectors (VM Inspectors) identify, document, and prescribe work on vegetation requiring work to comply with state regulatory requirements. Tree crews subsequently complete the prescribed work to maintain system safety and power reliability for our customers and communities.

PG&E's tree work goal is to achieve the longest practicable time between pruning cycles (two to three years when feasible), taking into consideration the tree's health and potential response to pruning. When appropriate, trees are prescribed for removal to achieve long-term mitigation. Generally, PG&E targets for removal small diameter trees (less than 12 inches diameter) and fast-growing species when achieving more than one year of clearance is not possible. Trees that are dead, dying, diseased or defective, and/or could fall into or otherwise impact PG&E facilities, are prescribed for work. Records of inspection and work are maintained in PG&E's system of record, One VM, which is described in Subsection k below.

PG&E's Routine/Annual Patrol has five steps associated with inspection, identification, and performance of tree work, as shown in Figure 8-2:

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24 GO 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances.

25 PRC § 4293. Fire protection areas; Required clearance according to voltage; Cutting or trimming decayed trees; Permitting exceptions.

26 PG&E 2026-2028 Wildfire Mitigation Plan, Section 9.2.1 (April 4, 2025).

FIGURE 8-2
ROUTINE/ANNUAL PATROL STEPS



- Step 1: Each year, PG&E develops a plan to ensure Electric Distribution overhead facilities are patrolled. Overhead lines are divided into projects, which are scheduled for inspection and associated tree work. The project schedule takes into consideration several factors, including the date of last patrol, location, seasonal access, power interruption history, and external stakeholder requirements. Once the project plan is approved, it is uploaded into One VM.
- Step 2: During the patrol, VM Inspectors identify, document, and prescribe vegetation work to comply with the state regulatory requirements described above. Information collected by VM Inspectors is documented in One VM. The VM system of record contains information such as tree location, work prescription, species, size class, and relevant notes pertaining to property access and safety alerts.
- Step 3: After trees are prescribed for work, a database manager reviews the records for completeness and potential constraints. If required, tree records are submitted to governing agencies for tree work approval and permits. When all constraints and dependences (such as owner permission or other access requirements, permits, etc.) are resolved, the work is assigned to tree crews.
- Step 4: Prescribed, unconstrained work is assigned to tree contractors. The contractors will perform tree work as

prescribed or, if applicable, document prescription changes. Prescription changes can occur if conditions change after the initial prescription such as when a property owner or agency removes a tree before a tree crew arrives. Tree crews, using their professional judgment, may determine a different prescription is safer for themselves, the public, and PG&E's assets. Changes may also occur to protect the tree's health, achieve a longer-term solution, or accomplish the same intended outcome more efficiently. Tree crews receive their work assignments and determine the necessary equipment based on the type of work. They contact customers to gain access to the site. If the work is on a roadside, they arrange for traffic control or permits. In areas with environmental restrictions, they follow best practices and mitigation processes and adhere to seasonal limited operating periods. Work types range from pruning small diameter trees in front yards to felling large, mature trees in state forests, which may require rigging or cranes. Tree crews perform assessments of the work area before starting, considering both the trees and proximity to energized powerlines. Tree crews must continually assess changing conditions to ensure safety for themselves and the public. After completing the tree work, crews manage debris according to PG&E's Wood Management procedures. Assigned tree work is closed in One VM to indicate the work is complete.

- Step 5: Vegetation Management Quality Control audits a statistically valid sample of locations at a 99 percent confidence level and 5 percent margin of error, following both inspection and tree work to identify any deficiencies. This confidence level and margin of error was approved in PG&E's 2023-2025 Wildfire Mitigation Plan R1.[27] If deficiencies are identified, they are field reviewed and corrected/worked, as necessary according to the procedures.

[27] PG&E 2023-2025 Wildfire Mitigation Plan R1, Section 8.2.5.2, p. 552 (April 6, 2023).

In addition to compliance with regulatory requirements (as described above), PG&E's Routine/Annual Patrol work reduces wildfire risk, increases public safety, and improves reliability of service to PG&E customers. This work prevents vegetation from growing into or falling into PG&E overhead distribution assets and causing power interruptions or ignitions. For these reasons, Routine/Annual Patrol work is a control for the Failure of Electric Distribution Overhead Assets Risk (DOVHD) and Wildfire (WLDFR) risks.

2) Forecast

Table 8-5 shows the recorded and forecast amounts for Annual Patrol.

TABLE 8-5
ANNUAL PATROL (MAT HNA)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	$668,426	$586,953	$588,483	$676,065	$781,754	$616,540	$609,677	$544,225

	Foundational Activities, Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	DOVHD-C001, WLDFR-C001	VM Distribution – Routine Patrols	2.4

The Annual/Routine Patrol forecast is based on historical cost data and the number of trees worked each year. The 2027 forecast anticipates a reduction from previous years in the number of trees requiring work, decreasing from approximately 1.41 million trees worked in 2024 to a forecast of approximately 1.14 million trees in 2027. However, the actual trees that require work can fluctuate from forecast due to environmental factors that influence annual tree growth and tree health. The anticipated decrease from 2024 to 2027 is attributed, in part, to the ongoing and planned undergrounding of overhead powerlines. As powerlines are placed underground in areas with trees, the number of trees needing

inspection and work decreases. This forecast assumes approximately 26 thousand fewer trees, annually, will require work due to undergrounding approximately 300 miles per year, resulting in 78 thousand fewer trees worked in 2027. Additionally, the high number of trees removed by Vegetation Management activities in past years is expected to result in a lower population of trees in proximity to powerlines and lower number of trees that require work.[28]

b. Vegetation Control – Compliance (MAT HNA)

1) Overview

PG&E's Vegetation Control program—also referred to as Pole Clearing—maintains firebreaks in compliance with PRC 4292[29] and PG&E's WMP.[30] To maintain this compliance, PG&E performs year-round pole clearing activities around subject Electric Distribution poles to maintain a firebreak of at least 10 feet in radius (horizontal distance out from the pole) to 8 feet above the ground, and all dead and dying vegetation above 8 feet up to the high-voltage conductors per Title 14 CCR 1254,[31] illustrated by Figure 8-3 below.

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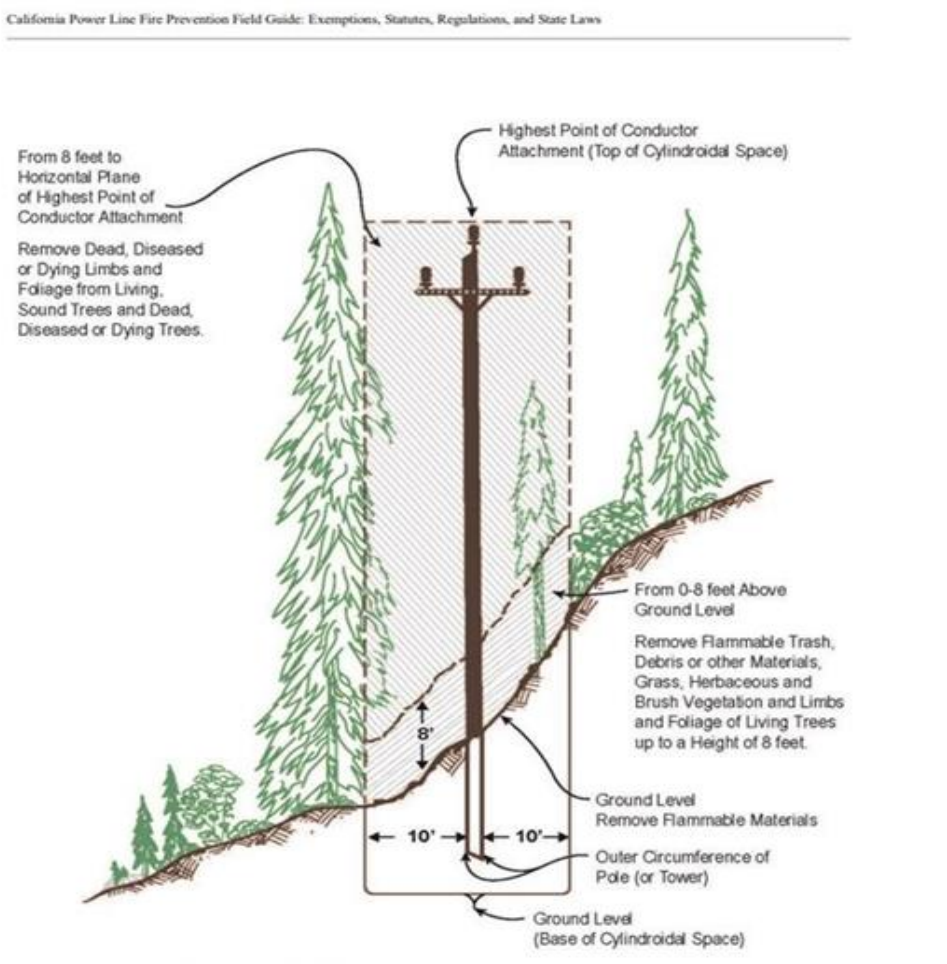
28 Exhibit (PG&E-4), WP 8-7.

29 PRC § 4292. Fire protection areas; Fire break clearing; Permitting exceptions.

30 PG&E 2026-2028 Wildfire Mitigation Plan, Section 9.4 (April 4, 2025).

31 Cal. Code Regs. tit. 14, § 1254, "The firebreak clearances required by PRC 4292 are applicable within an imaginary cylindroidal space surrounding each pole or tower on which a switch, fuse, transformer or lightning arrester is attached and surrounding each dead end or corner pole unless such pole or tower is exempt from minimum clearance requirements by provisions of 14 CCR 1255 or PRC 4296. The radius of the cylindroid is 3.1 m (10 feet) measured horizontally from the outer circumference of the specified pole or tower with height equal to the distance from the intersection of the imaginary vertical exterior surface of the cylindroid with the ground to an intersection with a horizontal plane passing through the highest point at which a conductor is attached to such pole or tower."

FIGURE 8-3
PRC 4292 14 CCR 1254 FIRE BREAK CLEARANCE REQUIREMENTS AROUND POLES



These requirements apply in the State Responsibility Areas[32] during the annual designated fire season. In addition, the requirements of PRC 4292 apply to Federal Responsibility Areas because the PRC has been adopted by Region 5 of the United States Forest Service (USFS). PG&E does not clear equipment exempted in Title 14 CCR 1255.[33] For these activities, PG&E relies upon the guidance and exemptions to PRC 4292[34] provided in

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32 State Responsibility Areas are recognized by the Board of Forestry and Fire Protection as areas where Cal Fire is the primary emergency response agency responsible for fire suppression and prevention.

33 Cal. Code Regs. tit. 14, § 1255. The minimum clearance provisions of PRC 4292 are not required around exempt poles and towers, including line junction, corner and dead end poles and towers.

34 PRC § 4292. Fire protection areas; Fire break clearing; Permitting exceptions.

Title 14 CCR 1254 and 1255[35] to determine which equipment configurations require firebreak maintenance in State Responsibility Areas and Federal Responsibility Areas.

PG&E's Vegetation Control program provides wildfire safety benefits to customers and the communities in which they live. A distribution pole subject to PRC 4292 clearing requirements has equipment that during normal operation may drop hot or molten material that could ignite surrounding fuels (e.g., a surge arrestor or fuse). Vegetation Control reduces the risk of wildfires caused by this equipment because it reduces vegetation fuels at the base of the poles by clearing vegetation.

The inspection cycle is generally from October to March. This cycle has been developed with the benefit of years of experience. By October, the clearing established by previous annual clearing cycles is complete and the vegetation growing cycle is complete. This is the optimal time to begin the inspection cycle to identify vegetation that should be mitigated during the next cycle.

Vegetation Control Field Technicians inspect all primary voltage distribution poles/equipment within State Responsibility Areas, USFS-Federal Responsibility Areas. During the inspection cycle, Vegetation Control Field Technicians inspect poles within the program scope, as described above, and prescribe work necessary to maintain compliance standards between work-cycles based on observed site-specific conditions. Subject poles are cleared before the start of fire season as declared by the Department of Forestry and Fire Protection (CAL FIRE). Field Technicians document any exceptions to this initial clearing in the system of record. Exceptions

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35 Cal. Code Regs. tit. 14, § 1254. The firebreak clearances required by PRC 4292 are applicable within an imaginary cylindroidal space surrounding each pole or tower on which a switch, fuse, transformer or lightning arrester is attached and surrounding each dead end or corner pole unless such pole or tower is exempt from minimum clearance requirements by provisions of 14 CCR 1255 or PRC 4296.

are limited to exemptions under 14 CCR 1255[36] or areas where work cannot be completed because of constraints such as customer interference, environmental permits, Caltrans and railroad permits, city/county encroachment permits, local agency permits, and operational delays, in which case any constraints are documented.

This initial clearing before the start of fire season begins in January and runs to the end of April. The goal is to complete all initial clearing prior to fire season unless work on a pole is documented to be constrained (i.e., unable to be cleared because of permitting issues, inability to access, etc.), as described above. All subject poles that are not exempt or constrained are assigned for evaluation and/or work during maintenance cycles that run from May through December. Poles are re-cleared as needed to maintain compliance throughout fire season.

Vegetation Control – Compliance (also called Pole Clearing – Routine), is a control for the Failure of Electric Distribution Overhead Assets (DOVHD) and Wildfire (WLDFR) risks because this work reduces the probability that fuels at the base of subject poles will ignite, thus avoiding outage and ignition outcomes.

2) Forecast

Table 8-6 shows the Vegetation Control – Compliance forecast, as well as the risks the work addresses and CBR (Cost Benefit Ratio).

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36 Cal. Code Regs. tit. 14, § 1255, The minimum clearance provisions of PRC 4292 are not required around exempt poles and towers, including line junction, corner and dead end poles and towers.

TABLE 8-6
VEGETATION CONTROL – COMPLIANCE (MAT HNA)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	$23,038	$18,416	$23,589	$22,826	$28,823	$17,697	$17,708	$17,708

	Foundational Activities, Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	DOVHD-C025, WLDFR-C080	Pole Clearing – Routine	2.0

The Vegetation Control – Compliance forecast is based on 2023 and 2024 recorded costs and the number of poles subject to PRC 4292[37] clearing requirements. The population of poles with equipment subject to PRC 4292 has declined over time due to equipment changes and powerlines placed underground. Historically, Vegetation Control recorded costs have included both poles cleared to comply with PRC 4292 requirements (compliance) and poles where clearance is not required by PRC 4292 but PG&E clears to reduce the risk of wildfire (risk reduction). Beginning in 2027, costs for Vegetation Control – Compliance pole clearing and Vegetation Control – Right-of-Way Clearing poles are forecasted separately. See Section B.3.3e below for the risk reduction forecast. The 2027 forecast is for compliance work on approximately 48.5 thousand poles.[38] Cost savings from contract structure changes implemented on October 1, 2024, are reflected in the forecast beginning in 2025. The Vegetation Control program had been under a lump sum contract. On October 1, 2024, PG&E transitioned from lump sum to a unit-based contract. Additionally, a unit price structure allows cost flexibility when subject poles are added or removed from the work population.

37 PRC § 4292. Fire protection areas; Fire break clearing; Permitting exceptions.

38 Exhibit (PG&E-4), WP 8-8, line 3.

c. Wood Management (MATs HNA, IGI, IGJ)

1) Overview

PG&E's Wood Management program involves chipping, relocating, or hauling wood from trees worked by PG&E Electric Distribution Vegetation Management activities. The wood management program is implemented in a manner that ensures site safety and environmental compliance. Wood Management activities support customers' efforts to maintain compliance with PRC 4291,[39] which requires property owners to maintain defensible space.

Vegetative material is a byproduct of our Vegetation Management tree work. Material less than four inches in diameter, sometimes referred to as "brush" or "slash," will be referred to as "debris" in this discussion. Typical treatment methods for debris include chipping and hauling or lopping and scattering in accordance with industry-leading practices. In some instances, PG&E will leave chips on site at the request of the property owner.

Vegetative material from tree work that is greater than four inches in diameter is referred to as wood. The wood belongs to and is the responsibility of the property owner and typically remains on site in a safe location. PG&E may offer wood management to customers if the wood meets qualifying criteria consistent with PRC 4291[40] and our procedures, which are summarized below.

- Qualifying Criteria consistent with PRC 4291
  - The wood must be generated by PG&E Vegetation Management activities.
  - Vegetative material must be greater than or equal to four inches in diameter.
  - Vegetative material must be accessible and operable with standard wood management equipment and located on slopes with less than 30 percent grade.

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39 PRC § 4291(a)(1) requires homeowners in State Responsibility Area (SRA)s to clear fuels from around their homes and outbuildings to form fuel-free, "defensible space" near them.

40 PRC § 4291(a)(1).

- The landowner/manager, or another authorized individual, must opt-into the Wood Management program.

- AND at least ONE of these criteria must be true:
  a) The vegetation is located within 100 feet of a human inhabitable structure, structure footprint, or campsite.
  b) The vegetative material is located within 15 feet of the access road to a human inhabitable structure, structure footprint, or campsite.
  c) The vegetative material is located within 15 feet of an outbuilding or propane tank.
  d) Other agreements have been established to manage the vegetative material.

Property owner authorization is required before PG&E can conduct wood management. The scope of PG&E's wood management may include relocating wood onsite or hauling wood offsite, and typically is focused on wood adjacent to structures, outbuildings, propane tanks, and roads. PG&E leaves wood onsite if relocating or hauling it would pose a safety risk or environmental, cultural, or accessibility concern.

PG&E conducts wood management in compliance with the California Forest Practice Rules (Title 14, California Code of Regulations, Chapters 4, 4.5, and 10). This program enhances customer experience by reducing work interruptions and refusals. By managing wood generated during our operations, we help customers comply with PRC 4291 regarding defensible space. Without this program, the risk of regulatory non-compliance would increase, potentially straining relationships with customers and stakeholders. Additionally, wood management is essential for public and worker safety along roads, especially in areas where there is insufficient space to leave the wood or where it could roll into the road.

2) Forecast

Table 8-7 shows the Wood Management Recorded and Forecast Costs.

TABLE 8-7
WOOD MANAGEMENT (MATs HNA, IGI, IGJ)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	HNA	Wood Management – Routine	–	–	–	–	$5,205	$3,518	$3,479	$2,818
2	IGI	Wood Management – Hazard Patrol	$2,871	$3,682	$5,397	$702	1,532	1,108	1,096	469
3	IGJ	Wood Management – Wildfire Mitigation Activities	92,733	57,533	155,050	48,624	39,574	55,219	64,210	58,830
4		Total	$95,604	$61,215	$160,447	$49,326	$46,311	$59,845	$68,785	$62,117

Foundational Activities, Risk Mitigation and Control Programs

	Risk Program ID	Risk Program Name	CBR
5	WLDFR-C083	VM Wood Management – Routine Patrol	Foundational
6	WLDFR-C085	VM Wood Management – Second Patrol	Foundational
7	WLDFR-M048	VM Wood Management – Mitigations	Foundational

The Wood Management forecast is based on recorded costs and average unit costs from 2024. Prior to 2023, recorded costs included Wood Management associated with the Enhanced Vegetation Management program (MAT IGJ), which generated a high volume of tree removals. The Enhanced Vegetation Management program concluded at the end of 2022, but some remaining Wood Management carried into 2023.

In 2027, Wood Management is forecasted to manage approximately 30 thousand fewer units of wood generated by tree removals compared to 2024, but at higher total cost due to increased Wildfire Mitigation Activity tree work. There is a direct correlation between the number of trees worked and demand for wood management. The forecast assumes that full tree removals and major tree dismantling will generate requests for wood management. It assumes that 19 percent of trees removed during Annual/Routine and Hazard Patrols and 35 percent of trees removed during Wildfire Mitigation Activities will result in wood management.

Costs for Wildfire Mitigation wood management are forecasted to increase from 2024 due to an additional 11 thousand trees

expected to require wood management. The average unit cost to manage Wildfire Mitigation trees is higher than Annual/Routine and Hazard Patrol.

As discussed in Section B.1.a above, the number of trees removed under the Annual/Routine and Hazard Patrol programs is forecasted to decline, while trees removed under Targeted Inspection, Tree Removal Inventory, and Vegetation Management for Operational Mitigations are forecasted to increase.[41] Overall, PG&E's Wood Management forecast for 2027 represents an increase from 2023-2026 levels, but not to the same levels as 2020-2022 when our VM programs included Enhanced Vegetation Management.[42]

2. Hazard Patrol (MAT IGI)

Since 2014, PG&E has carried out tree mortality risk initiatives to address prolonged drought and bark beetle infestations. Our original initiatives evolved into Hazard Patrol, which is comprised of Hazard Patrol Tree Work, and Fire Safe Council support.

PG&E's Hazard Patrol program (formerly known as Second Patrol or Tree Mortality program) conducts redundant inspections in high-risk areas. PG&E schedules these inspections so they are offset by approximately six months from Annual/Routine patrol of overhead primary and secondary distribution facilities. PG&E evaluates the areas to inspect within HFTD/HFRA areas through ongoing risk analyses.

PG&E's Fire Safe Council funding helps local communities reduce vegetation fuels near PG&E assets, create defensible space, improve ingress and egress, and support customers and communities in reducing the likelihood and impact of wildfires.

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41 Exhibit (PG&E-4), WP 8-14.

42 Exhibit (PG&E-4), WP 8-14.

a. Hazard Patrol Tree Work

1) Overview

PG&E conducts Hazard Patrol Tree Work in a subset of HFTD and HFRA that are high-risk areas to identify changes in conditions that occur between Annual/Routine patrols. These redundant patrols are directed by CPUC Resolution ESRB-4.[43] PG&E identifies vegetation that has died, is dying, or has developed outward symptoms of decline, biotic or abiotic factor created defects in tree (hazard tree) and/or has experienced growth that may interfere with compliance thresholds as described in General Order 95 Rule 35,[44] and PRC 4293.[45] All work identified during Hazard Patrol is documented, prescribed, and work completion is documented within the Vegetation Management system of record.

PG&E is revising its approach to the Hazard Patrol program to move from conducting inspections across all HFTD and HFRA Electric Distribution miles to a risk-based approach that PG&E will conduct on a subset of HFTD and HFRA Electric Distribution miles. This risk-based approach is described in PG&E's 2026-2028 WMP.[46]

This program will primarily focus on high wildfire risk and consequence locations, targeting tree work identification in the high-consequence parts of the System. These areas are informed

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43 See Resolution ESRB-4 (Issued June 16, 2014), p.14 OP 2 ("Investor Owned Electric Utilities must take practicable measures necessary to reduce the likelihood of fires associated with their facilities. These measures include: increasing vegetation inspections and removing hazardous, dead, and sick trees, and other vegetation near the [Investor-Owned Utility] IOUs' electric power lines and poles; sharing resources with the California Department of Forestry and Fire Protection (Cal Fire) to staff lookouts adjacent to the IOUs' property; and clearing access roads under power lines for fire truck access.").

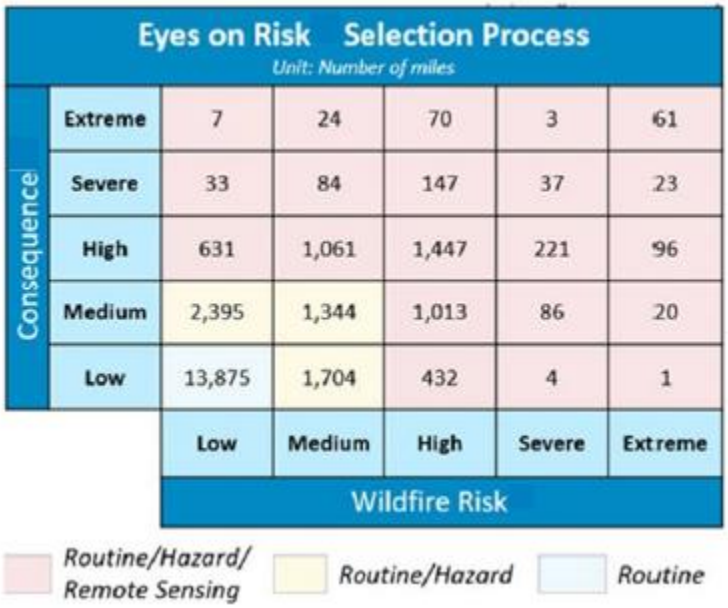
44 GO 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances.

45 PRC § 4293. Fire protection areas; Required clearance according to voltage; Cutting or trimming decayed trees; Permitting exceptions.

46 2026-2028 WMP, Section 9.2.2 (Apr. 4, 2025).

by the Wildfire Distribution Risk Model, where the areas of HFTD and HFRA are depicted in the categories of Extreme, Severe, High, Medium, and Low. The Hazard Patrol program will occur in the Extreme, Severe, High, and Medium categories. In addition, PG&E may also target Hazard Patrols in areas that may have previously been significantly impacted by events such as catastrophic wildfires. Figure 8-4 below indicates the framework utilized to identify the subset of HFTD and HFRA to in the Hazard Patrol program for further eyes on risk.

FIGURE 8-4
HAZARD PATROL INSPECTION SELECTION MATRIX.



Groupings for both consequence and wildfire risk are based on the percentiles of circuit segments based on the following categories: Extreme (0-1 percent), Severe (1-2 percent), High (2-10 percent), Medium (10-20 percent), Low (20-100 percent). The matrix allows for a correlation between wildfire risk and consequence, while also considering probability of ignition for vegetation drivers. PG&E anticipates determining “eyes on risk” values by year which may fluctuate depending on changes in overhead circuit mileage.

PG&E's Hazard Patrol also has five steps associated with inspection, identification and performance of tree work as shown in Figure 8-5.

FIGURE 8-5
HAZARD PATROL STEPS



- Step 1: Each year PG&E develops a plan to patrol overhead Electric Distribution overhead facilities. Overhead lines are divided into projects, which are scheduled for inspection and associated tree work. The project schedule takes into consideration various factors, including the date of last patrol, location, seasonal access, power interruption history, and external stakeholder requirements. Once the project plan is approved, it is uploaded into One VM.
- Step 2: During the patrol, VM Inspectors identify, document, and prescribe vegetation work to comply with state regulatory requirements described above. Information collected by VM Inspectors is documented in One VM. The VM system of record contains information such as tree location, work prescription, species, size class, and relevant notes pertaining to property access and safety alerts.
- Step 3: After trees are prescribed for work, a database manager reviews the records for completeness and potential constraints. If required, tree records are submitted to governing agencies for tree work approval and permits. When all constraints and dependences (like owner permission or other

access requirements, permits, etc.) are resolved, the work is assigned to tree crews.

- Step 4: Prescribed, unconstrained work is assigned to tree contractors to perform tree work as prescribed or document prescription changes. Prescription changes can occur if conditions change after the initial prescription, such as when a property owner or agency removes a tree before a tree crew arrives. Tree crews, using their professional judgement, may determine a different prescription is a safer for themselves, the public and PG&E's assets. Changes may also occur to protect the tree's health, achieve a longer-term solution, or accomplish the same intended outcome more efficiently. Tree crews receive their work assignments and determine the necessary equipment based on the type of work. They contact customers to gain access to the site. If the work is on a roadside, they arrange for traffic control or permits.

  In areas with environmental restrictions, they follow best practices and mitigation processes and adhere to seasonal limited operating periods. Work types range from pruning small diameter trees in front yards to felling large, mature trees in state forests, which may require rigging or cranes. Tree crews perform assessments of the work area before starting, considering both the trees and proximity to energized powerlines. Tree crews must continually assess changing conditions to ensure safety for themselves and the public. After completing the tree work, crews manage debris according to PG&E's Wood Management procedures. Assigned tree work is closed in the system of record to indicate the work is complete.
- Step 5: Vegetation Management Quality Control audits a statistically valid sample of locations at a 99 percent confidence level and 5 percent margin of error, following both inspection and tree work to identify any deficiencies. This confidence level and margin of error was approved in PG&E's 2023-2025 Wildfire Mitigation Plan R1. This confidence level and margin of

error was approved in PG&E's 2023-2025 Wildfire Mitigation Plan R1.[47] If deficiencies are identified, they are field reviewed and corrected/worked, as necessary according to the procedures.

PG&E developed the Hazard Patrol program to remove dead, rotten or diseased trees in order to reduce power interruptions and wildfire ignitions and comply with General Order 95, Rule 35,[48] and PRC 4293,[49] which mandate that PG&E maintain minimum distances around conductors and remove hazardous trees PG&E conducts Hazard Patrol to identify trees or tree parts that are located outside the anticipated minimum clearance zones under GO 95, Rule 35,[50] and PRC 4293,[51] and that pose a risk of striking overhead conductors.

Hazard Patrol also complies with CPUC Resolution ESRB-4,[52] which directs investor-owned utilities to take measures to reduce the likelihood of fires caused by or threatening utility facilities, including increasing vegetation inspections and the removal of hazardous, dead, and sick trees and other vegetation near the electric power

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47 PG&E 2023-2025 Wildfire Mitigation Plan R1, Section 8.2.5.2, p. 552 (April 6, 2023).

48 GO 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances.

49 PRC § 4293. Fire protection areas; Required clearance according to voltage; Cutting or trimming decayed trees; Permitting exceptions.

50 GO 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances.

51 PRC § 4293. Fire protection areas; Required clearance according to voltage; Cutting or trimming decayed trees; Permitting exceptions.

52 See Resolution ESRB-4 (Issued June 16, 2014), p. 14, OP 2 ("Investor Owned Electric Utilities must take practicable measures necessary to reduce the likelihood of fires associated with their facilities. These measures include: increasing vegetation inspections and removing hazardous, dead, and sick trees, and other vegetation near the [Investor-Owned Utility] IOUs' electric power lines and poles; sharing resources with the California Department of Forestry and Fire Protection (Cal Fire) to staff lookouts adjacent to the IOUs' property; and clearing access roads under power lines for fire truck access.").

lines and poles. The program mitigates risk by identifying and addressing vegetation that poses an immediate threat to PG&E facilities or a compliance risk due to changing conditions since the last Routine inspection. The Hazard Patrol program also mitigates future wildfire ignitions and reduces power interruptions. For these reasons, Hazard Patrol, formerly called Second Patrol, is a control for the Failure of Electric Distribution Overhead Assets (DOVHD) and (WLDFR).

2) Forecast

Table 8-8 shows Hazard Patrol Recorded and Forecast amounts as well as the risks the work addresses and CBR (Cost Benefit Ratio).

TABLE 8-8
HAZARD PATROL (MAT IGI)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	$77,397	$72,852	$97,907	$119,588	$120,207	$104,520	$103,624	$44,958
	Foundational Activities, Risk Mitigation and Control Programs							
	Risk Program ID		Risk Program Name				CBR	
2	DOVHD-C002, WLDFR-C002		VM Distribution – Second Patrols				3.1	

The Hazard Patrol forecast is based on historical cost data and the number of trees worked each year. Cost data includes both actual recorded costs and average costs per tree worked. The forecast anticipates a reduction in the number of trees requiring work. This anticipated decline is primarily attributed to the ongoing and planned undergrounding of overhead powerlines. As powerlines are placed underground in areas with trees, the number of trees needing inspection and work will decrease. Additionally, the high number of trees removed over time by Vegetation Management activities is expected to result in a lower population of trees in proximity to powerlines and lower number of trees that require work.

A lower volume of trees forecasted for work is also anticipated as the result of inspecting a subset of HFTD/HFRA miles.[53]

b. Fire Safe Councils

1) Overview

Since 2014, PG&E has implemented initiatives to address risks caused by prolonged drought and bark beetle infestations. PG&E's Fire Safe Council funding goes to community-based projects that focus on reducing vegetation fuels near PG&E assets, creating defensible space, improving ingress and egress, and supporting customers and communities in reducing the likelihood and impact of a wildfire.

PG&E assists local Fire Safe Councils (FSC) to implement safety efforts to reduce fire dangers. Local Fire Safe Councils, largely found in State Responsibility Areas,[54] are community-based, self-governed groups that focus on fire safety by:

- Conducting fuel reduction projects;
- Funding defensible space projects around homes required by PRC, Section 4291;[55]
- Coordinating fire safety workshops with insurance companies and home builders;
- Distributing fire safety materials;
- Teaching fire-safe home construction techniques; and
- Forming community safety networks.

PG&E works with Fire Safe Councils and their fiscal sponsors to identify "shovel-ready" project proposals, which consist of fuel reduction work, chipper programs, and escape route improvement projects that have been planned, prepared in the field, and permitted (if necessary), and that only require funding to implement. To be

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53 Exhibit (PG&E-4), WP 8-9.

54 State Responsibility Areas are recognized by the Board of Forestry and Fire Protection as areas where CAL FIRE is the primary emergency response agency responsible for fire suppression and prevention.

55 PRC 4291 (a)(1) requires homeowners in SRAs to clear fuels from around their homes and outbuildings to form fuel-free, "defensible space" near them.

eligible, each Fire Safe Council must be a 501(c)(3) non-profit or other non-governmental organization. Work in the field is conducted by private contractors employed by the Fire Safe Council, private party volunteers, homeowners, and Fire Safe Council members.

These projects benefit communities, customers, and PG&E by reducing fuels and creating fire breaks, which can help slow the spread of wildfire as well as improve ingress and egress and create defensible space that can be used by fire personnel to protect life and property.

2) Forecast

Table 8-9 shows the Fire Safe Council recorded and forecast amounts.

TABLE 8-9
FIRE SAFE COUNCILS (MAT IGI)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	$2,757	$4,651	$211	$2,293	$2,017	$1,489	$1,472	$631

The Fire Safe Councils forecast is based on historical recorded costs and an anticipated reduction in future projects funded. The reduction in the 2027 forecast compared to 2024 actual is because PG&E's overall wildfire mitigation efforts now include developing wildfire resiliency partnerships with agencies, non-profits, and community stakeholders to conduct larger landscape level projects. Some projects previously funded through the VMBA are forecasted in PG&E's Wildfire Resiliency Partnerships team, beginning in 2027. See Exhibit (PG&E 4), Chapter 4, for more information on these Wildfire Resiliency Partnerships. The projects funded under the Fire Safe Councils and recorded in the VMBA would be small-scale local projects that have mutual benefit to the community and PG&E asset protection. Projects during the 2027 GRC period are forecasted for $631 thousand each year.

3. Wildfire Mitigation Activities (MATs IGJ, HNA)

PG&E's forecast for Electric Distribution Vegetation Management Wildfire Mitigation activities includes funding for five primary activities:

- Targeted Inspection: Is a data-informed and risk-model-prioritized -approach designed to target vegetation in high-risk areas.
- Tree Removal Inventory: Is follow-up mitigation work on trees identified during inspections conducted as part of the legacy Enhanced Vegetation Management program, which concluded at the end of 2022. This work is conducted on trees that PG&E was unable to mitigate previously because of permitting, environmental, or other constraints.
- Vegetation Management for Operational Mitigation: Consists of the inspection and resulting tree mitigations based upon regional outage trends driven weather conditions or operation mitigations like Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS).
- Utility Defensible Space: Reduces vegetative fuels under and adjacent to power lines located within HFTD/HFRA areas.
- Vegetation Control/Right-of-Way Clearing: Is risk-informed pole clearing. Additional firebreaks are maintained in conformance with Public Utilities Code Section 8386.[56]

In addition to the activities described in this section, PG&E's Electric Distribution Vegetation Management Wildfire Mitigation activities may include additional work not reflected in this forecast as a result of the Proclamation of a State of Emergency issued by California Governor Gavin Newsom on March 1, 2025. In this order, Governor Newsom suspended state rules and requirements from the California Natural Resources Agency (CNRA) and the California Environmental Protection Agency (EPA), in order to fast-track critical projects protecting communities from wildfire. Through this process, utilities may request approval for projects that meet specified

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56 Pub. Util. Code § 8386 (c)(3) "A description of the preventive strategies and programs to be adopted by the electrical corporation to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risks."

criteria. If approved, this work must begin in 2025 and must be completed by the end of 2027. As of this GRC filing, PG&E is awaiting guidance from CNRA and the California EPA to clarify the types of work that may be submitted. If PG&E successfully submits projects for approval, this work would be accelerated and may impact the forecasts we have provided in this document.[57]

a. Targeted Inspection (MAT IGJ)

1) Overview

Targeted Inspection is a data-informed and risk-model-prioritized approach to identify and mitigate vegetation related wildfire risk in high-risk areas. These geographic areas, located in a subset of HFTD or HFRAs, are referred to as Areas of Concern. As part of its review of PG&E's 2022 WMP, the Office of Energy Infrastructure Safety issued Revision Notice 22-09, pursuant to which, PG&E took steps to use a predictive and risk modeling approach for vegetation management.

PG&E then developed Areas of Concern and a Focused Tree Inspection pilot in 2023. PG&E identified Areas of Concern v1 through a cross-functional effort using data and regional Vegetation Management and Public Safety Specialist expertise to develop polygons where trends indicated a higher probability of tree caused outages. PG&E updated its approach for Areas of Concern v2 as PG&E's risk models evolved over time, and in response to vegetation conditions. In particular, PG&E identified Areas of Concern v2 using its Wildfire Distribution Risk Model v4, shown in Figure 8-6 below, and will continue to evolve its identification of high risk areas throughout the 2027 GRC period.

In the 2027 GRC Period, targeted inspection will continue to mitigate the wildfire risk. These risk-informed activities will be

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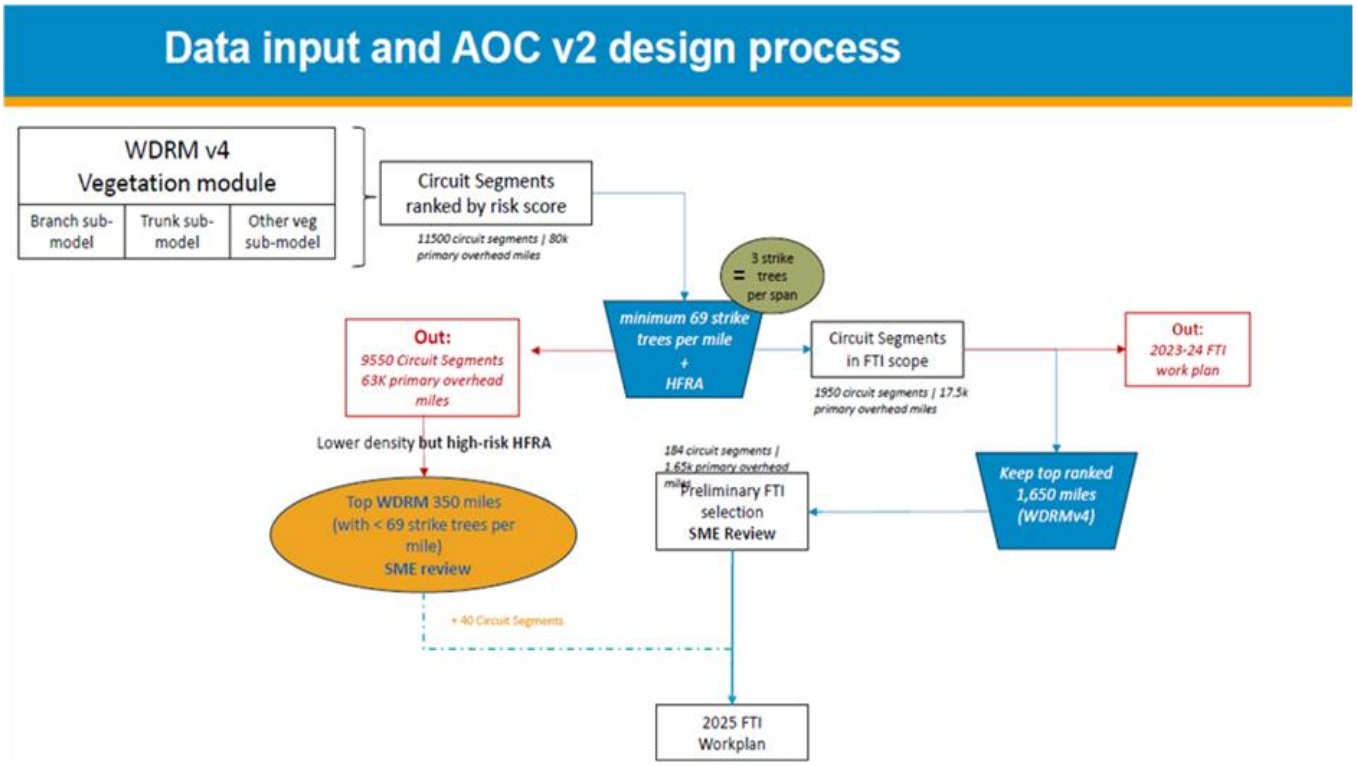
57 With growing fire risk, Governor Newsom proclaims state of emergency to fast-track critical wildfire prevention projects statewide (March 1, 2025), available at: https://www.gov.ca.gov/2025/03/01/with-growing-fire-risk-governor-newsom-proclaims-state-of-emergency-to-fast-track-critical-wildfire-prevention-projects-statewide/> (accessed April 24, 2025).

incorporated into VM's Distribution Inspection guidance documents where appropriate and executed through the VM Distribution Routine and/or Hazard Patrol programs. Due to the scope of this activity, tree work will predominately result in hazard tree removal identified through targeted inspection.

FIGURE 8-6
AREAS OF CONCERN (AOC) V2 DESIGN



PG&E typically conducts "Level 2" inspections in Areas of Concern to identify vegetation that has the potential to strike or come in contact with overhead conductors. A Level 2 inspection is conducted under the "ANSI A300 Tree Care Standards," approved by the American National Standards Institute (ANSI), as a Basic Tree Risk Assessment (Level 2). This tree risk assessment includes a ground-based visual inspection of the tree crown, trunk, trunk flare, above-ground roots, tree related site conditions, and significant targets. The assessment may include the use of common hand tools.

Targeted Inspection is a mitigation for the Failure of Electric Distribution Overhead Assets (DOVHD) and Wildfire with PSPS and EPSS (WLDFR, WPSPS, WEPSS) risks because it reduces the occurrence of damage to facilities, ignitions, and outages caused by vegetation contact with PG&E's equipment.

2) Forecast

Table 8-10 shows the recorded and forecast amounts for Targeted Inspection, as well as the risks the work addresses and CBR (Cost Benefit Ratio).

TABLE 8-10
TARGETED INSPECTION (MAT IGJ)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	–	–	–	$2,697	$58,966	$137,744	$114,053	$114,053
	Foundational Activities, Risk Mitigation and Control Programs							
	Risk Program ID			Risk Program Name			CBR	
2	DOVHD-M028, WLDFR-M028			VM Distribution – Targeted Inspection			6.5	

PG&E's targeted inspections began as a pilot program in 2023, during which about 250 miles were inspected and associated tree work was identified. In 2024 and 2025, the total annual mileage inspected increased to 1,500, resulting in a higher number of identified trees compared to 2023. The recorded cost in 2023 reflects a lower number of trees identified and worked during the pilot year. The Targeted Inspection forecast is based on the Focused Tree Inspection recorded cost data from 2023 and 2024, including the miles inspected and number of trees worked. Cost data comprises both actual recorded costs and average costs per tree.[58] More trees are identified during the annual mileage inspection than are worked annually. In 2023, during the pilot year,

[58] Exhibit (PG&E-4), WP 8-10.

the majority of costs were dedicated to inspection to build a tree work backlog, which carried over into 2024. The forecast includes working through backlog by the end of 2026. In 2027 and thereafter, the goal is to work the majority of trees identified during the current year's inspection.

In the 2023 WMP, PG&E's commitment for the Focused Tree Inspection program in 2024 and 2025 was the completion of 1,500 circuit miles of Focused Tree Inspection annually within Areas of Concern prioritized by vegetation management risk.[59] PG&E plans to continue this activity in 2026 and the 2027 GRC period,[60] incorporating targeted inspection work into VM Distribution's Annual/Routine Patrol and/or Hazard Patrol programs to increase operational efficiency and reduce visits to customers' properties. The anticipated average unit costs are shown in the forecast.[61]

b. Tree Removal Inventory (MAT IGJ)

1) Overview

Through the Tree Removal Inventory activity, PG&E systematically works the inventory of trees that had previously been identified for mitigation through PG&E's legacy Enhanced Vegetation Management program. This inventory includes trees that PG&E could not work due to permitting, environmental, or other constraints. PG&E maps outstanding Enhanced Vegetation Management tree records to the corresponding Wildfire Distribution Risk Model Circuit Protection Zones, which PG&E then prioritizes according to relative risk ranking. PG&E develops a scope of work every year to execute the work according to the risk ranked (1-N) Circuit Protection Zones.

VM Inspectors locate the vegetation points in the field to verify that the tree previously identified through the Enhanced Vegetation Management program still needs to be mitigated. If the tree is still

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59 2023-2025 WMP, R6, Section 8.2.2.2.5 (July 5, 2024).

60 2026-2028 WMP, R0, Section 9.2.1.6 (April 4, 2025).

61 Exhibit (PG&E-4), WP 8-10.

present and could impact overhead facilities in proximity to overhead conductors and is determined by the VM Inspector to present a potential risk, the tree is entered into the work queue for assignment to a tree contractor, barring external factors, such as customer interference and agency permits. PG&E conducts this work on a risk-ranked basis and continues to monitor the condition of these trees through our established Routine/Annual and Hazard Patrol (previously known as Second Patrol or Tree Mortality) programs until they are mitigated.

Tree Removal Inventory is a mitigation for the Failure of Electric Distribution Overhead Assets (DOVHD) and Wildfire Risk with PSPS and EPSS (WLDFR, WPSPS, WEPSS) risks because it reduces the occurrence of damage to facilities, ignitions, and outages caused by vegetation contact with PG&E's equipment.

2) Forecast

Table 8-11 shows the recorded and forecast amounts for Tree Removal Inventory as well as the risks the work addresses and CBR (Cost Benefit Ratio).

TABLE 8-11
TREE REMOVAL INVENTORY (MAT IGJ)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	–	–	–	$32,379	$14,168	$29,153	$41,040	$41,040
	Foundational Activities, Risk Mitigation and Control Programs							
	Risk Program ID		Risk Program Name				CBR	
2	DOVHD-M030, WLDFR-M030		VM Distribution – Tree Removal Inventory				3.9	

PG&E began the Tree Removal Inventory work in 2023. The Tree Removal Inventory forecast is based on recorded cost data in 2023 and 2024, an average cost per unit, and forecasted tree work.

The forecast increase compared to 2024 recorded costs is primarily driven by an increased tree work forecast.[62] Increased Tree Removal Inventory work to 42.8 thousand units annually through the 2027 GRC period is part of PG&E's efforts to complete its legacy Enhanced Vegetation Management program inventory by 2030, barring external factors. PG&E plans to integrate its Tree Removal Inventory work with its Annual/Routine Patrol to achieve greater operational and support efficiency. Integrated patrol and tree work results in fewer site visits to customers' properties, consolidated tree work oversight support, and administrative support costs such as environmental reviews, permits and constraint management. The anticipated average unit costs are shown in the forecast.[63]

c. Vegetation Management for Operational Mitigations (MAT IGJ)

1) Overview

PG&E's Vegetation Management for Operational Mitigations activity is related to the broader activities driven weather conditions or operational mitigations like Power Safety Power Shutoff and Enhanced Powerline Safety Settings (EPSS) program. The work for Vegetation Management for Operational Mitigations is part of PG&E's Vegetation Management forecast. Through the Vegetation Management for Operational Mitigations activity, PG&E performs targeted inspection and tree mitigations based upon regional outage trends driven by the Enhanced Powerline Safety Settings program historically and is expanded to other weather condition and operational mitigation management. Our wildfire mitigation capabilities have continued to evolve and mature since 2019 and several new mitigations, including EPSS, are now in place. The more sensitive settings of EPSS-enabled devices can lead to more frequent outages caused by vegetation. Vegetation Management for Operational Mitigations reduces the customer impacts of more

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62 Exhibit (PG&E-4), WP 8-11.

63 Exhibit (PG&E-4), WP 8-11.

frequent vegetation-caused outages due to the increased sensitivity of EPSS-enabled devices. Work plans depend on historical power interruptions caused by vegetation and the previous year's Enhanced Powerline Safety Settings outage data analysis. PG&E may incorporate Vegetation Management for Operational Mitigations as part of our weather-driven activities and consolidate its associated inspection and tree work into Hazard Patrol.

PG&E's Vegetation Management for Operational Mitigations activity steps associated with inspection, identification, and performance of tree work consist of the following:

- Step 1: Analysis of power interruption data is used to identify Enhanced Powerline Safety Settings enabled circuits or sections of circuits with higher incidents of vegetation caused interruptions. Projects for these circuits or segments are created in the Vegetation Management system of record.
- Step 2: During the project's patrol, VM Inspectors inspect vegetation in proximity to PG&E overhead Electric Distribution facilities with similar characteristics to vegetation that caused historical interruptions. VM Inspectors identify, document and prescribe vegetation work. Information is documented in the VM system of record.
- Step 3: After trees are prescribed for work, a database manager reviews the records for completeness and potential constraints. If required, tree records are submitted to governing agencies for tree work approval and permits. When all constraints and dependences (like owner permission or other access requirements, permits, etc.) are resolved, the work is assigned to tree crews.
- Step 4: Prescribed, unconstrained work is assigned to tree contractors to perform tree work as prescribed or document prescription changes.

All tree work conducted in support of Vegetation Management for Operational Mitigations is captured in the VM system of record.

Vegetation Management for Operational Mitigations is a mitigation for the Failure of Electric Distribution Overhead Assets (DOVHD) and Wildfire Risk with PSPS and EPSS (WEPSS) risks because it reduces the occurrence of damage to facilities, ignitions, and outages caused by vegetation contact with PG&E's equipment.

2) Forecast

Table 8-12 shows the recorded and forecast amounts for Vegetation Management for Operational Mitigations, as well as the risks, the work addresses and CBR (Cost Benefit Ratio).

TABLE 8-12
VEGETATION MANAGEMENT FOR OPERATIONAL MITIGATIONS (MAT IGJ)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	–	–	–	$13,053	$7,117	$7,836	$7,747	$6,387

	Foundational Activities, Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	DOVHD-M029, WLDFR-M029	VM for Operational Mitigations (VMOM)	12.9

Vegetation Management for Operational Mitigations began in 2023. The Vegetation Management for Operational Mitigations forecast is based on recorded costs in 2023 and 2024, units worked in 2023 and 2024, an average cost per unit, and forecasted units. PG&E is forecasting work on approximately 25 thousand operational mitigation trees through the 2027 GRC period.[64]

The 2027 forecast decrease as compared to 2024 recorded is primarily driven by a lower number of trees forecasted for work. PG&E plans to incorporate Vegetation Management for Operation Mitigations into its Hazard Patrol to achieve greater efficiency and anticipated cost saving.

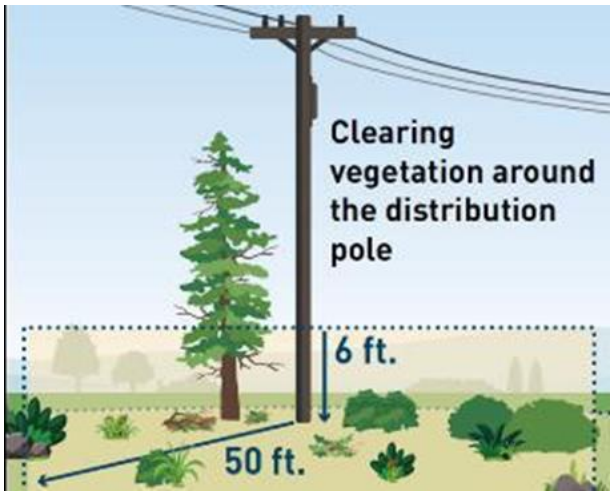
64 Exhibit (PG&E-4), WP 8-12.

d. Utility Defensible Space (MATs HNA, IGJ)

1) Overview

PG&E's Utility Defensible Space program reduces vegetative fuel accumulations within a 50-foot radius around poles that are selected using the Wildfire Distribution Risk Model and local subject matter experts' input, in furtherance of PG&E's commitment to reducing wildfire spread and damage to utility equipment from wildfires. The program scope includes clearing brush, grasses, and ladder fuels from four inches to six feet. Trees greater than four inches in diameter at breast height are pruned but not removed. The program includes maintenance of previously cleared poles. Utility Defensible Space's vegetative fuel clearing scope is depicted by Figure 8-7.

FIGURE 8-7
UTILITY DEFENSIBLE SPACE



The Utility Defensible Space program modifies these fuels beneath and adjacent to overhead primary distribution voltage equipment in the CPUC designated HFTD/HFRA and PG&E identified High Fire Areas. As a mitigation program, its scope is limited to treatments that minimize environmental impact and do not conflict with other resource protection regulations, particularly California Forest Practice Rules.

PG&E developed the current Utility Defensible Space standard to reduce fuel accumulation and limit the rapid spread of wildfire in proximity to PG&E assets, regardless of ignition source. The Utility Defensible Space program is integral for the safe and reliable operation of PG&E's assets.

Although the Utility Defensible Space program is not a regulatory requirement or PG&E WMP commitment, this program reduces vegetative fuels under and adjacent to power lines located within HFTDs and HFRAs. PG&E developed the Utility Defensible Space program in 2021 to reduce live fuels in the area of PG&E's assets to reduce wildfire spread and protect electric equipment.

The program scope adheres to the following criteria for poles within its scope:

- Within 50 feet of every designated pole, Utility Defensible Space increases the vertical and horizontal clearance between vegetation to reduce surface-level fuel buildup.
- Utility Defensible Space creates a 6-foot vertical clearance from the ground or understory to the lowest tree branch.
- Utility Defensible Space creates a vertical clearance that is three times the shrub's height from understory shrubs to the lowest branch of a tree (e.g., a 3-foot-tall shrub must be 9 feet away from the lowest tree branch).
- Utility Defensible Space removes all shrubs, or, if not practicable, ensures shrub-to-shrub horizontal spacing must be at least twice the shrub's height.
- Utility Defensible Space removes accumulated surface-level fuels to a maximum depth of 18 inches.

The Utility Defensible Space program enhances safety and reduces wildfire risks by minimizing utility-related ignitions, slowing down fire development near PG&E assets, and improving operational safety for critical equipment. Additionally, removing ladder fuels and creating fire breaks with shrub spacing, as well as clearing dead or dying debris from customer properties, further helps to slow down forest fires.

Utility Defensible Space is a mitigation for the Wildfire (WLDFR) risk because, as described above, it reduces ignitions and slows the rate of wildfire spread.

2) Forecast

Table 8-13 shows the recorded and forecast amounts for Utility Defensible Space, as well as the risks the work addresses and CBR (Cost Benefit Ratio).

TABLE 8-13
UTILITY DEFENSIBLE SPACE (MATs HNA, IGJ)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	$5,221	$14,162	$28,703	$3,787	$5,088	$3,954	$3,957	$3,957

	Foundational Activities, Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-M041	Utility Defensible Space Distribution	2.7

The Utility Defensible Space forecast is based on recorded costs in 2023 and 2024. The 2027 forecast does not include the recorded costs from 2020 to 2022 as part of its forecast basis because the program's scope was different during the WMP period. The forecast anticipates spending patterns consistent with 2023-2026 and consistent input costs.

e. Vegetation Control – Right-of-Way Clearing (MAT HNA)

1) Overview

Vegetation Control – Right-of-Way Clearing performs clearing between and around poles with: (1) equipment that is exempt from PRC Section 4292[65] regulations inside State Responsibility Area boundaries or outside State Responsibility Area that is within HFTD and HFRA or (2) poles with equipment that is not exempt from PRC

[65] PRC §4292. Fire protection areas; Fire break clearing; Permitting exceptions.

Section 4292[66] outside of State Responsibility Area boundaries that is within HFTD and HFRA. PG&E may also create vegetation clearing from pole to pole under the powerlines in areas PG&E determines appropriate.

Through this program, PG&E creates/maintains additional firebreaks throughout its service area. This work is aligned with PUC Section 8386.[67] These firebreaks are based on PG&E guidance (for risk reduction work) or local agreements. PG&E selects locations to reduce risk, improve access to equipment, allow for safe Supervisory Control and Data Acquisition (SCADA) operations, enhance public safety, supplement other mitigations, and protect assets from wildfires regardless of cause.

Vegetation Control – Right-of-Way Clearing is a mitigation for the Failure of Electric Distribution Overhead Assets (DOVHD) and Wildfire Risk with PSPS and EPSS (WLDFR, WPSPS, WEPSS) risks because it reduces the occurrence of ignition caused by PG&E's equipment and the rate of spread of wildfire.

2) Forecast

Table 8-14 shows the recorded and forecast amounts for Vegetation Control Right-of-Way Clearing as well as the risks the work addresses and CBR (Cost Benefit Ratio).

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66 PRC §4292. Fire protection areas; Fire break clearing; Permitting exceptions.

67 Pub. Util. Code § 8386 (c)(3) "A description of the preventive strategies and programs to be adopted by the electrical corporation to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risks."

TABLE 8-14
VEGETATION CONTROL – RIGHT-OF-WAY CLEARING (MAT HNA)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	–	–	–	–	$33,347	–	–	$5,544

	Foundational Activities, Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	DOVHD-M027, WLDFR-M027	Vegetation Control/Right-of-Way Clearing	4.0

The Vegetation Control – Right-of-Way Clearing forecast, starting in 2027, is forecasted separately from Vegetation Control – Compliance. Historically, costs for both were recorded together.[68] Because Vegetation Control Right-of-Way Clearing and Vegetation Control - Compliance are separate components of PG&E's Risk Assessment and Mitigation Phase and WMP, separate forecasts are appropriate.

In 2024, a stand-alone risk reduction pole clearing project occurred, recording costs separately from compliance poles at an average unit cost approximately four times higher than previous years. During the 2027 GRC period, in response to changing environmental conditional, PG&E anticipates clearing additional poles, similar to those cleared during the 2024 stand-alone risk reduction pole clearing project, with an average unit cost comparable to the 2023 recorded Vegetation Control costs.[69]

4. Supporting Activities (MATs HN#, IGI, IGJ)

Supporting Activities are key to the completion of work for all of PG&E's forecasted Vegetation Management work and include processes for compliance with laws and regulations and PG&E standards and procedures, and for the maintenance of records that are traceable, verifiable, accurate, and complete.

68 Exhibit (PG&E-4), WP 8-8.

69 Exhibit (PG&E-4), WP 8-8.

Table 8-15 shows the summary of the recorded and forecast amounts for the Supporting Activities.

TABLE 8-15
ALL PROGRAM SUPPORTING ACTIVITIES (MATs HN#, IGI, IGJ)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	HN#	Safety	$1,482	$22,644	$21,477	$45,862	$32,802	$26,311	$26,295	$21,453
2	HN#, IGI, IGJ	Quality Management	29,744	70,266	86,362	67,153	53,951	95,027	90,624	51,595
3	HN#	Public Education	600	397	328	2,035	480	303	300	243
4	HN#, IGIJ, IGJ	Environmental Review	5,953	7,876	11,625	2,022	1,548	1,965	1,754	1,780
5	HN#	Customer Relations	–	–	–	249	440	384	380	287
6	HN#. IGI, IGJ	Program Management	–	–	–	22,829	37,187	45,026	47,510	27,799
7	HN#	Construction Management	–	–	–	0	2,825	4,992	5,847	2,777
8	HN#	Document Governance (Standards & Procedures) & Training	–	–	–	5,814	6,433	5,284	5,226	4,233
9	HN#, IGI, IGJ	Constraints Management	–	–	–	45,160	48,466	49,330	49,483	27,351
10	HN#, IGJ	Data and Technology	–	–	–	42,110	39,388	50,408	47,972	47,355
		Total	$37,779	$101,183	$119,793	$233 ,233	$223,520	$279,030	$275,389	$184,872

Foundational Activities, Risk Mitigation and Control Programs

	Risk Program ID	Risk Program Name	CBR
11	WLDFR-C082	VM Support – Routine Patrol	Foundational
12	WLDFR-C084	VM Support – Second Patrol	Foundational
13	WLDFR-M047	VM Support – Mitigations	Foundational

Vegetation Management Support Activities manage the efficient execution of all PG&E's forecasted Vegetation Management activities, as described in more detail below.

a. Safety

1) Overview

Vegetation Management Safety activities focus on the safety of our workforce and overhead Electric Distribution facility operations.

Utility vegetation work is classified as high risk and requires Occupational Safety and Health Administration (OSHA) programs and training to mitigate task and location-specific hazards. Contractors or subcontractors working for PG&E must meet the Contractor Safety program requirements in PG&E's Utility Standard SAFE-3001S, which outlines the minimum requirements for contractor safety management and PG&E's health and safety expectations for work performed on behalf of PG&E.

Tree crew vendor personnel are trained on PG&E SAFE-0101 (Contractor Safety Program Requirements) before starting work. Starting in August 2020, PG&E tracked all OSHA requirements in a third-party tracking program known as ISNetWorld.

Safety program elements include:

- Competency Assessment Yard;
- Vegetation Operations Inspectors; and
- Employee Safety.

a) Competency Assessment Yard

PG&E established a Competency Assessment Yard to evaluate the knowledge, skills, and abilities of Vegetation Management workers performing core Vegetation Management operations activities. The assessment program verifies that personnel can complete Vegetation Management work safely, correctly, and in compliance with PG&E standards and procedures, federal and state regulations, and PG&E-adopted industry guidelines (e.g., ANSI). The Assessment Yard currently assesses all tree crew workers, with assessment

programs for Vegetation Management Inspectors in development and assessments being planned for additional roles.

The Competency Assessment Yard has trained Qualified Evaluators to implement the assessments, following standard operating procedures for a fair and consistent evaluation of worker skills in a controlled and engineered environment. The Assessment Yard provides most assessments to the workforce, and a mobile assessment team takes ground-based tree crew assessments to locations across the PG&E service territory.

PG&E's Competency Assessment program verifies competency for tasks such as limbing and bucking, aerial saw work, and prescribing work.

FIGURE 8-8
COMPETENCY ASSESSMENT YARD



These assessment verifications are documented and visible to observers and inspectors in the field. This assessment includes standards and procedures for PG&E Vegetation Management assessment verifications. The Competency Assessment Yard is a critical resource for training and observing Vegetation Management workers in their core skill

areas, to ensure that workers can perform their work functions safely and consistent with PG&E's compliance obligations and standards.

b) Vegetation Operations Inspectors

Vegetation Operations Inspectors are experienced tree workers/arborists who observe tree crews' work quality and adherence to processes and procedures. This oversight identifies issues that require correction and provides tree crews and internal operations with feedback. Vegetation Operations Inspectors understand how Vegetation Management work is performed safely, correctly, and consistently with PG&E procedures. The Vegetation Operations Inspectors identify work practice corrective issues. They document and provide feedback to workers. The observations from Vegetation Operations Inspectors informs the Competency Assessment Yard and other Vegetation Management Safety and compliance initiatives.

c) Employee Safety

PG&E develops safety initiatives to enhance safe practices, elevate workforce skills, improve work quality, and strengthen safety culture. These initiatives utilize data from the Competency Assessment Yard, Vegetation Operations Inspectors, and other sources within the Vegetation Management organization. Employee Safety initiatives provide operational and safe practice information, reinforce the importance of a safety culture, build situational awareness, and address patterns requiring correction identified through data and observations. These efforts are part of PG&E's continuous process of improving Vegetation Management.

The Competency Assessment Yard, Vegetation Operations Inspectors, and Employee Safety initiatives enhance worker safety, quality, and reliability. These efforts have reduced system-wide safety incidents and fostered a strong safety

culture. Comprehensive tree crew safety assessments by our Vegetation Management teams have led to an 83 percent reduction in climber-related Serious Injuries and Fatalities over the past three years.

2) Forecast

Table 8-16 shows the recorded and forecast amounts for Safety Support.

TABLE 8-16
SAFETY SUPPORT ACTIVITIES (MAT HN#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	$1,482	$22,644	$21,477	$45,862	$32,802	$26,311	$26,295	$21,453

The Safety forecast is based on recorded costs in 2023 and 2024. Forecast costs include internal and external labor costs for safety observers and inspectors. The forecast anticipates decreased costs for observers and inspectors as overall tree work decreases.[70] PG&E established a Safety Assessment Yard in 2023 and the forecast includes ongoing costs for the Safety Assessment Yard operation.

b. Quality Management

1) Overview

PG&E's Vegetation Management Quality Management consists of two quality programs. These programs are Vegetation Management Quality Control (VM QC) and Vegetation Management Quality Assurance (VM QA).

PG&E's VM QC activities confirm that recently completed inspections and tree work meet quality standards. Inspections and tree work are assessed against PG&E's standards and procedures, and regulatory requirements. PG&E's VM QA activities audit a

70 Exhibit (PG&E-4), WP 8-13.

representative sample of PG&E overhead facilities to evaluate compliance with PRC 4292[71] and 4293,[72] and GO 95, Rule 35.[73] PG&E conducts VM QA field reviews independent of inspection and tree work schedules. Quality Solutions, a dedicated business analyst team, provides back-office support to these Quality Management activities.

a) Quality Control

Through VM QC, PG&E verifies that Vegetation Management work meets operational standards. VM QC program auditors perform field reviews after Vegetation Management Operations has completed inspections and/or tree work to verify the applicable procedural scope has been met. VM QC for Annual/Routine Patrol and for Vegetation Control are 2026-2028 WMP commitments.

VM QC adheres to and monitors compliance with the following Regulatory Requirements and recommendations:

- CPUC GO 95, Rule 35;[74]
- PRC 4292;[75]

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71 PRC § 4292. Fire protection areas; Fire break clearing; Permitting exceptions.

72 PRC § 4293. Fire protection areas; Required clearance according to voltage; Cutting or trimming decayed trees; Permitting exceptions.

73 General Order 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances.

74 General Order 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances.

75 In SRAs, CAL FIRE has delegated its responsibility as the primary responder to fires to a "co-operator," such as a countywide fire district (i.e., Kern, Marin, and Santa Barbara counties), that acts on behalf of, and in concert with, CAL FIRE. SRAs are usually in wildland areas and comprise about 60 percent of PG&E's service territory. Since SRAs are usually remote, CAL FIRE or the co-operator may not be located nearby, and response times may be significantly longer. As a result, there is an increased risk that a fire started in an SRA could spread quickly.

- PRC 4293;[76] and
- CCR, Title 14, sections 1250, 1251, 1252, 1253, 1256, 1257 and 1258.[77]

b) Quality Assurance

PG&E's VM QA performs a systematic review of Annual/Routine patrol and of Vegetation Control work to verify compliance with regulations, including GO 95, Rule 35[78] and PRC 4292,[79] and 4293,[80] along with internal PG&E standards and procedures. VM QA audits are conducted by a team of qualified and skilled compliance and risk consultants. Consultants conduct audits independent of the timing of pre-inspection and tree work projects to capture the system's status at a specific moment in time. PG&E creates an annual VM QA plan to identify areas of higher potential risk and to ensure that each area is audited at least once per year.

Auditors conduct audits based on a random sample of distribution line segments at a 95 percent confidence level and a 3.25 percent margin of error. VMQA audits are based on a represented sample of asset miles to measure the vegetation compliance results of the surrounding vegetation. Historically, a 30 to 40 mile range has proven to be a stable sampling size. This results in a lower margin of error when the sample

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76 PRC § 4293. Fire protection areas; Required clearance according to voltage; Cutting or trimming decayed trees; Permitting exceptions.

77 Cal. Code Regs. Tit. 14, § 1250: Purpose to provide specific exemptions; 1251: Definitions that apply (i.e., "firebreak"); 1252: Areas where PRC 4292-4296 apply in SRA; 1253: Time when PRC 4292-4296 apply; 1256: Minimum clearance provisions – PRC 4293; 1257: Exempt minimum clearance provisions; 1258: Tree lines – When electric conductors are fastened to living, sound trees, the requirements of PRC 4292 and 4293 shall apply.

78 GO 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances.

79 PRC § 4292. Fire protection areas; Fire break clearing; Permitting exceptions.

80 PRC § 4293. Fire protection areas; Required clearance according to voltage; Cutting or trimming decayed trees; Permitting exceptions.

population is increased. Quality Solutions creates the random sample of line segments using ArcGIS modeling software. Auditors perform root cause analyses on the audit findings and provide a written report designed to identify trends and areas of focus. The conclusion of a VM QA audit may yield both short and long-term corrective actions. If systemic issues are identified, VM QA consultants assist Vegetation Management Operations with developing action plans to implement solutions.

PG&E's VM QA audits identify trees that may pose a risk of power interruption and other public safety issues. These risks can come in the form of outages or ignitions caused by trees growing into high-voltage conductors, or whole trees or parts of trees falling onto PG&E equipment and causing a wire-down event. VM QA audits also improve work quality, consistency, and compliance by identifying areas that are performing well and areas that require more focus.

PG&E's VM QA provides an independent, statistically valid assessment of PG&E's compliance with regulatory requirements. Results from the audit help PG&E determine if proper controls are in place for reducing risk of outages, ignitions, or non-compliance with regulatory requirements. VM QA activities are also a requirement of the 2026-2028 WMP.

Additional VM QA program components include the following:

- Records Quality Management: Records Quality Management provides business analyst support to conduct desktop review audits of records to ensure conformance with VM standards and procedures.
- Quality Solutions: Quality Solutions supports PG&E's Vegetation Management Quality Management audit programs. Quality Solutions provides weekly releases of sample data for auditing, creates and maintains data collection tools, validates and presents collected data, and compiles reports viewed by internal groups and external

organizations to track compliance ratings and performance metrics. PG&E relies on the auditing tools and data provided by the Quality Solutions group.

Quality Solutions also maintains and supports the reporting and validation of data for WMP commitments. The data offer insights into VM performance.

In summary, PG&E's VM QM activities ensure recently completed inspections and tree work meets quality standards and regulatory requirements. VM QM: (1) assesses that VM activities adhere to the relevant state laws, regulations, and WMP commitments, (2) reduces the risk that trees are missed during inspection, (3) supports uniformity and consistency within the VM operations activities by ensuring consistent quality over time and across Regions and Divisions, (4) provides a reliable and safer electric grid, which benefits customers and communities, and (5) provides a feedback loop to identify opportunities for improvement.

2) Forecast

Table 8-17 shows the recorded and forecast amounts for Quality Management activities.

TABLE 8-17
QUALITY MANAGEMENT (MATs HN#, IGI, IGJ)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted					Forecast			Workpaper Reference
			2020	2021	2022	2023	2024	2025	2026	2027	
1	HN#	Quality Management – Routine Patrol	$29,301	$46,626	$50,655	$58,329	$39,320	$70,818	$70,077	$39,862	WP 8-4, lines 12-15
2	IGI	Quality – Hazard Patrol	173	1,568	854	1,531	368	2,589	2,559	1,124	WP 8-5, line 7
3	IGJ	Quality – Wildfire Mitigation Activities	269	22,072	34,854	7,293	14,263	21,620	17,987	10,609	WP 8-6, line 9
4		Total	$29,744	$70,266	$86,362	$67,153	$53,951	$95,027	$90,624	$51,595	

The Quality Management forecast is based on costs recorded for 2023 and 2024. The forecast's primary component is labor, including internal PG&E employees and external contractors. Work volume and WMPs impact the amount of labor required to audit work. The forecast considers 2026-2028 WMP changes, Annual/Routine and Hazard Patrol work forecast decreases, and incorporating Wildfire Mitigation activities into Annual/Routine and Hazard Patrol.[81]

c. Public Education

1) Overview

PG&E's Vegetation Management Public Education activities provide information regarding the hazards posed by high voltage lines and vegetation through community and agency engagement and public education.

Public Education efforts include: (1) educating third-party tree workers and customers about tree and power line safety; (2) creating communication materials such as brochures, "right tree right place" posters, door hangers, and websites; (3) outreach efforts, such as representation at local Fire Safe Councils and forestry committees, booths at community fairs and garden shows, or tree planting events; and (4) support and maintenance of "Tree Line USA" and certification of International Society of Arboriculture (ISA) Arborists and additional industry certifications.

Public Education is a control for the Failure of Electric Distribution Overhead Assets (DOVHD), Public Contact with Intact Energized Electric Equipment (PCEEE), and Failure of Electric Distribution Underground Assets (DUNGD) risks because the information provided through this program is intended to reduce the likelihood of the public's dangerous encounters with PG&E's equipment.

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81 Exhibit (PG&E-4), WP 8-13.

2) Forecast

Table 8-18 shows the recorded and forecast amounts for Public Education activities.

TABLE 8-18
PUBLIC EDUCATION (MAT HN#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	$600	$397	$328	$2,035	$480	$303	$300	$243

	Foundational Activities, Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	DOVHD-C024, PCEEE-C002, DUNGD-C017	Public Safety Awareness	27.2

The Public Education forecast is based on historical recorded costs. Recorded costs in 2023 were higher than typical years due to several stand-alone projects completed in 2023.[82] Future years' costs anticipate a return to typical spending patterns.

d. Environmental Review

1) Overview

PG&E's Environmental Review of Vegetation Management work supports Vegetation Management work throughout PG&E's service territory and coordinates closely among environmental field specialists, environmental planners, biologists, cultural specialists, and other environmental specialists to help stay in compliance with environmental requirements. PG&E's Environmental Review group is also responsible for working with various state, federal, and local agencies when Vegetation Management work is within their jurisdictions.

PG&E's Environmental Review activities address environmental regulatory compliance and permitting requirements for Vegetation

82 Exhibit (PG&E-4), WP 8-13.

Management work. Environmental Review evaluates vegetation work activities prior to the work start and provides conditions and/or requirements that work activities must comply with to avoid and/or minimize environmental impact.

2) Forecast

Table 8-19 shows the recorded and forecast amounts for Environmental Review activities.

TABLE 8-19
ENVIRONMENTAL REVIEW (MATs HN#, IGI, IGJ)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	Workpaper Reference
1	HN#	Environmental Review – Routine	$5,953	$7,876	$11,625	$904	$609	$648	$641	$572	WP 8-4, line 16
2	IGI	Environmental Review – Hazard Patrol	–	–	–	249	14	17	17	7	WP 8-5, line 8
3	IGJ	Environmental Review – Wildfire Mitigation Activities	–	–	–	869	925	1,299	1,095	1,201	WP 8-6, line 12
4		Total	$5,953	$7,876	$11,625	$2,022	$1,548	$1,965	$1,754	$1,780	

The Environmental Review forecast is based on recorded costs in 2023 and 2024. The forecast costs are primarily internal PG&E labor and contract labor. The 2027 forecast compared to 2024 recorded costs assumes a decrease driven by a lower number of units forecasted for work. The anticipated reduction in Annual/Routine Patrol and Hazard Patrol work is expected to lead to fewer environmental reviews. Incorporating Wildfire Mitigation Activities into Annual/Routine Patrol and Hazard Patrol is expected to create efficiencies by reducing redundant property visits.

e. Customer Relations

1) Overview

PG&E's Vegetation Management Customer Relations activities promote positive customer interactions by providing advanced notification of Vegetation Management inspections and tree work. Customer Relations representatives interact with customers before, during, and after Vegetation Management work. The Customer Relations program includes the Customer Outreach organization, which notifies customers by text or Interactive Voice Recording prior to Pre-Inspection, Tree Work activities, and Vegetation Control (prior to each inspection/work cycle at the project level). When customers have questions regarding notifications, the Customer Outreach organization provides support.

During Vegetation Management work, Customer Outreach Specialists, Local Customer Experience Wildfire Safety, and Customer Escalations representatives provide email, phone, and field support to Vegetation Management co-workers and/or direct customer support as needed.

After Vegetation Management work is completed, PG&E emails surveys to approximately 30 percent of customers who have contacted the Call Center regarding tree work on their property. Customer feedback is analyzed by the Data Analytics Group. Results are used to identify areas for improvement.

2) Forecast

Table 8-20 shows the recorded and forecast amounts for Customer Relations.

TABLE 8-20
CUSTOMER RELATIONS (MAT HN#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted					Forecast		
			2020	2021	2022	2023	2024	2025	2026	2027
1	HN#	Customer Relations	–	–	–	$249	$440	$384	$380	$287

The Customer Relations forecast is based on costs recorded in 2023 and 2024. Recorded costs for Customer Relations are not available for the period from 2020 to 2022. During the 2020 GRC period, if activity costs existed, they were aggregated under broader vegetation management activities. Starting in 2023, costs were recorded separately to better track and manage specific Customer Relations activities. The forecast considers the existing cost for survey platform, support from Customer Outreach and Customer Insights organizations, an expansion of proactive notification efforts to additional VM programs, and support from the Data Analytics Group via the use of generative AI models.

f. Program Management

1) Overview

PG&E's Vegetation Management Portfolio Management Organization (PMO) leads and manages the program scopes and processes. The PMO provides direction for the programs' work plans and goals and leads process development and program standardization.

The PMO is responsible for managing scope changes or additions to the workplans. The PMO works closely with operations and other internal stakeholders to ensure operational needs are met and commitments and progress on the workplans are cross-functionally visible.

2) Forecast

Table 8-21 shows the recorded and forecast amounts for Program Management activities.

TABLE 8-21
PROGRAM MANAGEMENT (MATs HN#, IGI, IGJ)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted					Forecast		
			2020	2021	2022	2023	2024	2025	2026	2027
1	HN#	Program Management – Routine	–	–	–	$6,649	$23,968	$24,820	$24,556	$17,494
2	IGI	Program Management – Hazard Patrol	–	–	–	4,966	6,209	7,843	7,754	2,338
3	IGJ	Program Management – Wildfire Mitigation Activities	–	–	–	$11,214	$7,010	$12,364	$15,200	$7,967
4		Total	–	–	–	$22,829	$37,187	$45,026	$47,510	$27,799

The Program Management forecast is based on costs recorded in 2023 and 2024. Recorded costs for Program Management were not recorded separately during the 2020 GRC period from 2020 to 2022. During this period, costs were aggregated under broader vegetation management activities. Starting in 2023, costs were recorded separately to better track and manage specific Program Management activities. The forecast costs are primarily labor (both internal PG&E and contract support).[83] The forecast assumes efficiencies gained by integrating Wildfire Mitigation Activities into Annual/Routine Patrol and Hazard Patrol.

g. Construction Management

1) Overview

Construction Management supports the Vegetation Management organization by providing support with safety, cost control, sourcing liaison, invoice improvement, process improvement, resource management, and contractor oversight, as well as operational support. Construction Management supports PG&E conducting Vegetation Management work safely and in compliance with PG&E's standards and procedures. Construction Management also supports stable cost structures and cost containment.

a) Contract Management Support

- Cost Control: A goal of Construction Management is establishing cost controls and related compliance procedures across programs. Construction Management facilitates Cost Control initiatives, including "request for X" events as part of the procurement process, contract negotiations, change order request review, and ad-hoc contractor changes.
- Sourcing Liaison: Construction Managements' partnership with Electric and Vegetation Management Procurement has

83 Exhibit (PG&E-4), WP 8-13.

helped support shifts within the contract workforce during the contract term. As PG&E's sourcing needs shift, so does the demand on the Vegetation Management workforce. Sourcing Liaison supports better sourcing alignment, which has enabled continuous support of those needs.

- Invoice Improvement: Centralized invoicing supports the invoice management process for Vegetation Management Contractors. These tasks support audit compliance that includes invoice validation, ensuring vendors are paid accurately and timely, and that invoices are reviewed for accuracy and adherence to contracting standards.

b) Operational Support

Construction Management partners with both Contractors and Operations by working through contractual, operational, quality and safety concerns.

Construction Management partners with other VM organizations to simplify and standardize processes each year.

2) Forecast

Table 8-22 shows the recorded and forecast amounts for Construction Management activities.

TABLE 8-22
CONSTRUCTION MANAGEMENT (MAT HN#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	–	–	–	–	$2,825	$4,992	$5,847	$2,777

The Construction Management forecast is based on recorded costs in 2023 and 2024. Recorded costs for Construction Management were not recorded separately during the 2020 GRC period from 2020 to 2022. During this period, costs were aggregated under broader vegetation management activities. Starting in 2023, costs were recorded separately to better track and

manage specific Construction Management activities. The forecast costs are primarily labor resources, both internal PG&E employees and external contractors.[84]

h. Vegetation Management Document Governance (Standards & Procedures) and Training

1) Overview

Document Governance manages and governs Vegetation Management standards, procedures, bulletins, and other organizational documents. These documents support safety, code compliance, consistency of application, and repeatable results. All documents are published in the Technical Information Library (TIL) where employees and non-employee contract workers performing Vegetation Management work tasks in the field can access them. Each document has an assigned Owner, Approver, and Document Contact(s). As any changes in process occur, the applicable governing document is reviewed and updated. Documents are reviewed periodically to ensure continued compliance with regulations, codes, and policies.

Performing work tasks consistent with these guidance documents helps PG&E VM adhere to regulations, and reduces vegetation caused power interruptions and ignitions.

VM Communication and Training issues information associated with new or updated guidance documents. Training may include in-person instructor led and web-based training delivery methods. Refresher trainings are provided as needed.

Training is delivered to ensure internal VM Inspectors are trained on the expectations of their job, procedures, and the arboricultural knowledge needed to conduct effective utility tree line inspections as well as environmental stewardship expectations. Starting in 2024, to support vendors' arboricultural trainings, PG&E made in-person (instructor led) training materials available to vendors to use as part of their internal training activities.

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84 Exhibit (PG&E-4), WP 8-13.

Training helps to develop a competent and qualified work force to ensure consistent program implementation and listing practices, which supports the safe and efficient use of resources and continued compliance with regulations, codes, and policies. Identification of the correct work at the right time reduces unnecessary work and helps focus efforts on vegetation that pose risk to the facilities.

2) Forecast

Table 8-23 shows the recorded and forecast amounts for Vegetation Management Document Governance (Standards, Procedures) and Training.

TABLE 8-23
VEGETATION MANAGEMENT DOCUMENT GOVERNANCE (STANDARDS & PROCEDURES) AND TRAINING (MAT HN#)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	–	–	–	$5,814	$6,433	$5,284	$5,226	$4,233

	Foundational Activities, Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-C081	Vegetation Management Document Governance (Standards, Procedures) and Training	Foundational

The Vegetation Management Document Governance (Standards & Procedures) and Training forecast is based on costs recorded in 2023 and 2024. Recorded costs for Document Governance and Training were not recorded separately during the 2020 GRC period from 2020 to 2022. During this period, costs were aggregated under broader vegetation management activities. Starting in 2023, costs were recorded separately to better track and manage specific Document Governance and Training activities. The forecast costs are primarily labor resources, both internal PG&E

employees and external contractors.[85] The forecast anticipates continued support for document and training activities implemented in 2024.

i. Constraints Management

1) Overview

PG&E's Vegetation Management Constraints Management activities support timely resolution of constrained work. A constraint occurs when circumstances impact PG&E Vegetation Management execution, such as inspections or tree work. These circumstances could include, but are not limited to: physical conditions, environmental delays, customer/landholder interferences or non-contacts, permitting delays/restrictions, weather conditions, removed or destroyed assets, active wildfire, or other safety or operational considerations.

Timely resolution of constrained work is important to comply with federal and state laws including:

- CPUC GO 95, Rule 35;[86]
- PRC 4292;[87]
- PRC 4293;[88] and
- CCR, Title 14, sections 1250, 1251, 1252, 1253, 1256, 1257, and 1258.[89]

PG&E's Constraint Management responsibilities include:

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85 Exhibit (PG&E-4), WP 8-13.

86 GO 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances.

87 PRC § 4292. Fire protection areas; Fire break clearing; Permitting exceptions.

88 PRC § 4293. Fire protection areas; Required clearance according to voltage; Cutting or trimming decayed trees; Permitting exceptions.

89 Cal. Code Regs. Tit. 14, § 1250: Purpose to provide specific exemptions; 1251: Definitions that apply (i.e., "firebreak"); 1252: Areas where PRC 4292-4296 apply in SRA; 1253: Time when PRC 4292-4296 apply; 1256: Minimum clearance provisions – PRC 4293; 1257: Exempt minimum clearance provisions; 1258: Tree lines – When electric conductors are fastened to living, sound trees, the requirements of PRC 4292 and 4293 shall apply.

- Ownership and continuous improvement of constraints procedures:
  - VM Distribution Interference Procedure (TD-7102P-02);
  - VM Bird Nest Procedure (TD-7110P-01);
  - VM Riparian Review Procedure (TD-7102P-16);
  - VM Encroachment Permitting Procedure (TD-7102P-31);
- Ownership of Vegetation Management Department constraints reporting and performance management;
- Support of timely and quality permit applications;
- Agency Managed Lands permitting/notification; and
- Escalation support internally with other functional areas in PG&E, and externally with agencies themselves.

The activities listed above support continued focus, and progress in completing work that is complex in nature and may require additional coordination or review/approval prior to proceeding. Because of this, constraints management and the Constraints Team are important in managing risk and the success of PG&E's Vegetation Management activities.

2) Forecast

Table 8-24 shows the recorded and forecast amounts for Constraints Management.

TABLE 8-24
CONSTRAINTS MANAGEMENT (MATs HN#, IGI, IGJ)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	HN#	Constraints – Routine	–	–	–	$36,190	$36,670	$36,256	$35,840	$20,408
2	IGI	Constraints – Hazard Patrol	–	–	–	7,106	8,448	7,508	7,422	1,798
3	IGJ	Constraints – Wildfire Mitigation Activities	–	–	–	1,863	3,348	5,566	6,221	5,144
4		Total	–	–	–	$45,160	$48,466	$49,330	$49,483	$27,351

The Constraints Management forecast is based on recorded costs in 2023 and 2024. The forecast costs are primarily labor resources (both internal PG&E employees and external contractors). Forecast components include agency permitting coordination, application and management, biological and cultural review, reports and monitoring, and field surveys (contractor labor). Constraints Management costs were not recorded during the 2020 GRC period from 2020 to 2022. During this period, constraints management costs were aggregated under broader vegetation management activities. Starting in 2023, costs were recorded separately to better track and manage specific Constraints Management activities. The 2027 forecast compared to 2024 recorded costs assumes a decrease driven by a lower number of units forecasted for work.[90] The anticipated reduction in Annual/Routine Patrol and Hazard Patrol work is expected to lead to fewer constraints required to manage. Incorporating Wildfire Mitigation Activities into Annual/Routine Patrol and Hazard Patrol is expected to create efficiencies by bundling constraint submittal to agencies and reducing tracking, and fewer property visits and customer contacts.

j. Vegetation Management Data and Technology

1) Overview

Vegetation Management Data and Technology supports the suite of technologies used to maintain compliance with state and federal laws and PG&E's Vegetation Management wildfire risk mitigation activities. The program is designed to support traceable, verifiable, accurate, and complete record keeping. The technologies include a suite of integrated applications, databases, and servers that document the inspection of our assets and the mitigation of identified hazards.

Vegetation Management Data and Technology provides user support to over 4,000 users and oversight and guidance of data and technology partners to develop and enhance VM tools. It also

90 Exhibit (PG&E-4), WP 8-13.

prepares information and reports for regulatory filings and regulatory requests; creates custom queries and reports; conducts data quality and GIS spatial data analysis; and creates tools to automate vendor billing and support new risk mitigation initiatives.

a) One VM Application Development and Support

Developed in 2022, One VM is the core system supporting Electric Distribution Vegetation Management inspection and mitigation work to maintain compliance with GO 95, Rule 35,[91] PRC 4292,[92] and PRC 4293,[93] as described throughout this testimony chapter. The system is comprised of mobile applications to dispatch workers to specific assets and collect data in the field, a GIS map interface to visualize work in relation to PG&E assets, a web interface to plan and track work progress, and a reporting server to generate operational reports and serve as a repository for data requests.

One VM costs include software licenses, servers, internal and external resources to support software development, testing, management, user support, communication and training.

b) Geographical Information System Application Development and Support

PG&E's Geographical Information System (GIS) is a critical component to the suite of Vegetation Management applications and provides electronic maps to both field and office personnel.

GIS map information is displayed in programs including One VM, VMPI2, Fieldmaps, Survey123 and online tools such as ArcGIS, providing awareness of vegetation in relation to

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91 GO 95, Rule 35 Section III. Where overhead conductors traverse trees and vegetation, safety and reliability of service demand that certain vegetation management activities be performed in order to establish necessary and reasonable clearances the minimum clearances.

92 PRC § 4292. Fire protection areas; Fire break clearing; Permitting exceptions.

93 PRC § 4293. Fire protection areas; Required clearance according to voltage; Cutting or trimming decayed trees; Permitting exceptions.

company assets, and property boundaries. GIS also alerts personnel to important safety information. Examples of map applications supported include Quality Control, Targeted Inspection, Tree Removal Inventory, wildfire and non-wildfire emergency cleanup work, wood management and removal, general construction, system hardening, undergrounding, priority tree identification and field crew resource tracking.

GIS costs include software licenses, servers, internal and external resources to perform geospatial analyses to fulfill operational and regulatory data requests, software development, testing, management, and user support.

c) Report Development and Support

A dedicated group tracks and manages internal and external data requests and aids in consistent, accurate, and timely responses. This group coordinates with appropriate subject matter experts, documents how the data was collected, and provides the data to the requesting party.

Costs for this area include Microsoft Power BI, a data visualization tool, and Structured Query Language (SQL) developer resources and management personnel.

d) Vendor Invoicing and Contract Management System

The high volume of work completed by Vegetation Management vendors requires high levels of automation to efficiently invoice over one million trees annually. The Vegetation Management Invoicing system uses completed work records from One VM and the legacy Vegetation Management Database (VMD) to generate automated invoices for vendors and provide PG&E management tools to review and confirm work was completed and invoiced accurately.

Another program, Nexus, is a vendor facing application that allows vendors to submit and review invoices, and upload supporting documentation to document work performed. Internal PG&E resources use the VM Invoicing website to

review vendor invoices, approve invoice for payment, or return invoices to the vendor for revision.

The Contractor Time and Material System is a related application which allows PG&E to store negotiated rates for work activities. These rates are used by the VM Invoicing system to automatically calculate invoice amounts to ensure accurate invoicing.

Costs for invoicing include developer resources, management personnel, user support, and data and technology support.

e) Legacy System Development and Support

The “legacy” VM Data and Technology system, Vegetation Management Database (VMD), was the original system of record for all VM work from 1998 until it was replaced by One VM in early 2023. The VMD system is currently used for a small amount of distribution work and is expected to continue to be in use during the 2027 GRC period. The system is now primarily used for historical reporting and analytical research. The active components of the system include the BackOffice website and the VMPI2 mobile application.

Ongoing costs for the VMD system include developer resources, management personnel, user support, and data and technology support.

f) Remote Sensing

Remote Sensing can include multiple different technologies such as LiDAR, satellite, and high-resolution imagery. LiDAR and high-resolution imagery can be acquired through different modalities such as fixed wing aircraft, helicopter, vehicle, backpack, etc. Remote sensing data can be used to support data and analytics for the condition of vegetation in proximity to overhead electric assets. Information such as radial clearance of vegetation, volume of trees with strike potential, and tree health characteristics can all be derived from remote sensing

and used to support data driven decision making and inform inspection. PG&E will continue to use various remote sensing technologies to monitor the condition of vegetation near electric assets to support planning, identify operational efficiencies, and provide situational awareness. PG&E's forecast includes costs for GIS developer resources, vendor data acquisition, management and data and technology support.

g) General Data and Technology Support

The existing suite of Vegetation Management Data and Technology systems relies on several supporting technologies that require support from other groups within PG&E's IT department. Costs are sometimes incurred from departments outside Vegetation Management. For example:

- The Nexus invoicing application is housed on PG&E's CITRIX server and incurs technology support costs to deploy new versions of the application. Structured query language administrators are occasionally called in to analyze server performance or restore data from backups.
- The Enterprise Secure File Transfer system is used to transfer data between Vegetation Management systems and other PG&E systems and outside entities and incurs support and maintenance costs.

The tablets used for the VMPI2 application incurs software licensing, cellular connectivity and hardware and user support costs.

2) Forecast

Table 8-25 shows the recorded and forecast amounts for Vegetation Management Data and Technology work.

TABLE 8-25
VEGETATION MANAGEMENT DATA AND TECHNOLOGY (MATs HN#, IGJ)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Recorded Adjusted					Forecast		
	2020	2021	2022	2023	2024	2025	2026	2027
1	–	–	–	$42,110	$39,388	$50,408	$47,972	$47,355

	Foundational Activities, Risk Mitigation and Control Programs		
	Risk Program ID	Risk Program Name	CBR
2	WLDFR-C077	Vegetation Management Data and Technology – Distribution	Foundational

The Vegetation Management Data and Technology forecast is based on recorded costs in 2023 and 2024. The forecast costs are primarily labor resources (both internal PG&E employees and external contractors), supporting existing technologies, and enhancements. The 2027 forecast compared to 2024 recorded costs assumes continued existing labor support and an increase to implement technology enhancements and improve efficiencies.[94]

C. Compliance

1. Deferred Work Analysis

The 2023 GRC Decision (OP 4) requires PG&E to continue following the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC.[95] The Deferred Work Settlement requires PG&E to include testimony on deferred work if the following criteria are met:

a) The work was requested and authorized based on representations that it was needed to provide safe and reliable service;

b) PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and

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94 Exhibit (PG&E-4), WP 8-13.

95 Pursuant to D.23-11-069, p. 900, OP 4, "Pacific Gas and Electric Company shall continue to follow the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC, subject to the limitations of Public Utilities Code Section 8386.3, which restricts the diversion of revenues authorized for certain wildfire mitigation activities."

c) PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.

For work covered in this chapter, PG&E applied these criteria as explained in Analysis of "Deferred Work" discussion set forth in the Electric Distribution Forecast Summary and Investment Planning chapter.[96] This analysis is presented in the workpapers supporting that chapter.[97]

Based on this analysis, no work included in this chapter was identified as "deferred work" under the terms of the Deferred Work Settlement.

D. Vegetation Management Balancing Account (VMBA)

In the 2023 GRC Decision (D.23-11-069), the Commission directed PG&E to modify the VMBA from a two-way balancing account to a one-way balancing account to record expense for VM Programs up to adopted amounts.[98] As a one-way balancing account, PG&E may not seek recovery of actual spending above the total adopted funding cycle amount in the VMBA and is obligated to return to customers any unspent funds (actual expenses less than adopted expenses). PG&E proposes to continue the VMBA as a one-way balancing account as authorized in D.23-11-069, modified as described below.

In this rate case period, PG&E proposes to modify the VMBA to record capital revenue requirements associated with capital additions because PG&E anticipates incurring software and/or hardware costs for its Data & Technology activities. These activities may include, but are not limited to, tree tagging and tree tag registry, work scheduling optimization, and mobile device licensing, each of which is capitalized in accordance with existing accounting policies. PG&E summarizes its request to modify the existing cost recovery mechanisms as described in this exhibit and associated revenue requirements in Exhibit (PG&E-10), "Results of Operations," Chapter 16 "Balancing Accounts."

E. Conclusion

Based on the demonstration above and on the evidence presented in the associated attachments and workpapers to this chapter, PG&E respectfully requests that the Commission:

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96 Exhibit (PG&E-4), Ch. 2, Section E.1.b.

97 Exhibit (PG&E-4), WP 2-19.

98 D.23-11-069, p. 821, FOF 234, p. 878, COL 177.

1) Adopt the expense forecasts in Section A.2, Table 8-1;
2) Adopt the specific post Test Year attrition proposed for the activities forecasted in MWC HN;
3) Approve the continuation of the one way Vegetation Management Balancing Account (VMBA) to track and record expenses for PG&E's Electric Distribution Vegetation Management activities discussed herein; and
4) Approve PG&E's proposal to modify the Vegetation Management Balancing Account to record capital expenditures as described in Section D.

PG&E continues to invest in its vegetation management activities to directly support public safety, service reliability, and regulatory compliance through management of vegetation near PG&E's electric distribution facilities. These proactive measures serve the important purpose of reducing wildfire risk, improving the safety of PG&E's electric systems, and protecting customers and the public through a time of extreme climatic influences.

PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 9

ELECTRIC DISTRIBUTION CAPACITY, ENGINEERING AND PLANNING

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
ELECTRIC DISTRIBUTION CAPACITY, ENGINEERING AND PLANNING

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ELECTRIC DISTRIBUTION CAPACITY, ENGINEERING AND PLANNING

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PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
ELECTRIC DISTRIBUTION CAPACITY, ENGINEERING AND PLANNING

A. Introduction and Summary

1. Overview

The purpose of this chapter is to demonstrate that Pacific Gas and Electric Company's (PG&E) expense and capital expenditure forecasts for its Engineering and Planning Program (Engineering and Planning Program) and its Electric Distribution Capacity Program (Capacity Program) are reasonable and should be approved by the California Public Utilities Commission (CPUC or Commission). The Engineering and Planning Program supports a variety of asset management and operating activities and is necessary to plan, design, and operate PG&E's electric distribution system. PG&E uses the Capacity Program to manage substation and distribution line investments necessary to meet customer demand. The Commission's approval of this forecast will allow PG&E to fulfill its obligation to serve customers, proactively plan for California's decarbonization goals, meet new regulatory requirements and industry standards, cost-effectively mitigate equipment overload conditions, and provide safe, reliable, and timely service to customers.

This program, through the capacity projects it enables, allows new industries to establish themselves and existing customers to expand. Over the last five years, some of the customers that were energized through capacity projects include electric vehicle (EV) fast charging stations, data centers served at the distribution voltage level, last-mile delivery centers, technology and software developers, EV battery manufacturers, college campus expansions, and residential subdivisions.

Customers, from EV charging stations to shopping centers and agricultural growers, expect timely energization of added load. If the grid cannot accommodate this new load, customer energization is delayed until such time as the grid is made ready to serve the load. This grid readiness is necessary to prevent equipment from carrying more load than what it was

originally designed for. Overloading can cause overheating, equipment damage, and sustained customer outages. Energization delays, however, can have a direct impact on California's economic progress and climate goals. As Senate Bill 410 "Powering up Californians Act" found:

> Delays in energization, including service upgrades, are costly both to the customers awaiting service and to other customers deprived of the downward pressure on rates.[1]

Furthermore, customers have testified to the need for adequate funding that enables timely energization. As one EV charging station developer stated in their 2023 GRC testimony:

> Ultimately, long energization timelines have a direct detrimental effect on EV adoption.[2]

And another customer recognized in their 2023 GRC testimony that utilities:

> …need the financial and operational flexibility to deliver that capacity in a timely manner that does not put the utilities in the position of being a barrier to economic and environmental progress in the state.[3]

But how does a utility minimize energization timelines? Historically utilities waited for formal applications for service to initiate work. But this has proven to be "reactive and conservative."[4] This is why Energy Division, in its Staff Proposal for the High DER Proceeding directs utilities towards a proactive approach to capacity upgrades:

> The new paradigm of the distribution planning and execution process must become more proactive by anticipating new loads and being prepared to serve them without lengthy distribution upgrades.[5]

2. Summary of Request

PG&E requests that the Commission:

- Adopt the expense forecasts in Section A.2, Table 9-1.
- Adopt the capital expenditure forecasts in Section A.2, Table 9-2.

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1 Senate Bill (SB) 410, Sec. 1, 932(a)(8).

2 Testimony of Damon Franz, 2023 GRC A.21-06-021 (January 30, 2024), p. 7.

3 Testimony of Steve W. Chriss, 2023 GRC A.21-06-021 (January 30, 2024) p. 15.

4 R.21-06-017 Staff Proposal for the High DER Proceeding, (March 13, 2024), p. 14.

5 R.21-06-017 Staff Proposal for the High DER Proceeding, (March 13, 2024), p. 14.

- Adopt the specific post Test-Year attrition proposed for the Capacity Program capital forecasts as described in Section C.1, C.2, C.3, C.4, and C.5.

Forecasts in this chapter are shown with no escalation included in all expenses and capital totals, except for the transformer purchases within the Distribution Line Capacity Program. PG&E will offset escalation through work execution efficiencies to improve affordability.

TABLE 9-1
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MWC	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	Workpaper Reference
1	FZ	E Dist Planning & Ops Engineer	$15,158	$15,488	$13,324	$16,733	$18,105	$16,522	$19,670	$19,670	WP 9-3
2	Total		$15,158	$15,488	$13,324	$16,733	$18,105	$16,522	$19,670	$19,670	

TABLE 9-2
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

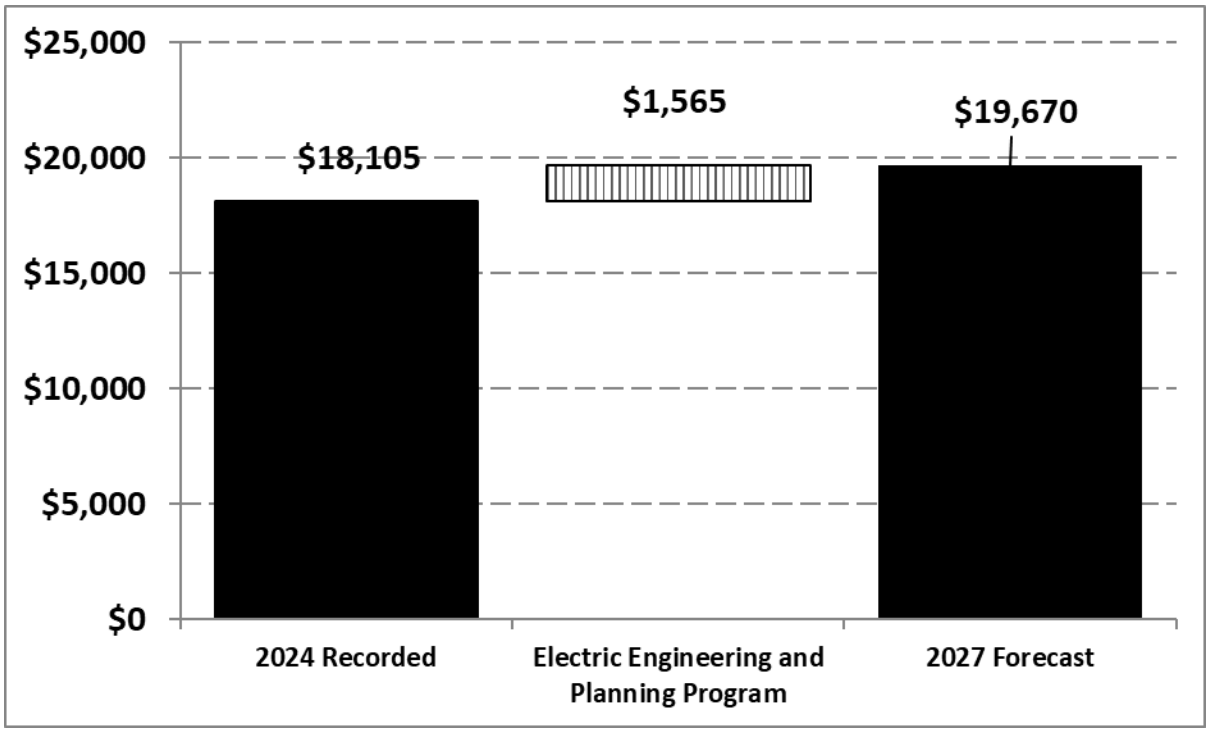
Line No.	MWC	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030	Workpaper Reference
1	06	E Dist Line Capacity	$107,267	$157,046	$155,039	$155,262	$217,258	$290,414	$349,141	$289,077	$452,435	$441,680	$496,681	WP 9-17
2	46	E Dist Subst Capacity	35,574	53,741	60,417	67,283	100,240	188,799	262,494	245,691	246,193	325,527	313,962	WP 9-18
3	Total		$142,841	$210,787	$215,456	$222,544	$317,497	$479,213	$611,635	$534,768	$698,628	$767,207	$810,643	

Note: The values reflected in this table may vary from the initial Results of Operations (RO) Model provided with PG&E's GRC filing due to timing differences. The RO Model will be updated to incorporate these errata in a future submission.

a. Expense

Figure 9-1 provides an expense walk identifying key drivers for the difference in the 2027 forecast as compared to 2024 recorded. Each driver is summarized below.

FIGURE 9-1
EXPENSE WALK 2024-2027
(THOUSANDS OF NOMINAL DOLLARS)

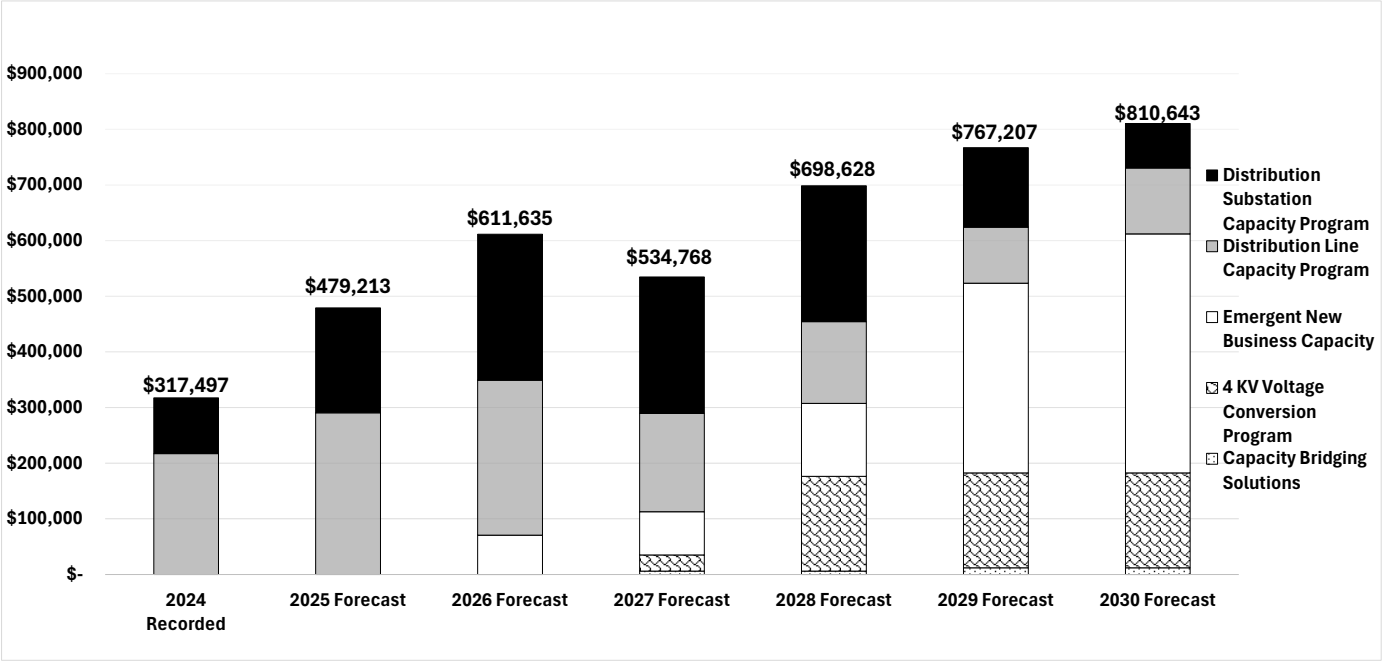


The 2027 expense forecast is based on 2024 recorded amounts with an increase to allow Electric System Planning & Reliability to remain adequately staffed to maintain base commitments while learning and using new planning tools. The requested forecast assumes an increase for Distribution Planning Engineer work (MAT FZA) to account for increasing engineering work needed to support the increasing complexity of planning tools and the forecasting process. This includes scenario planning analyses, pending load survey implementation, and an increase in phase balancing studies to better utilize existing systems.

b. Capital

Figure 9-2 provides the capital forecast from 2024 to 2030 for the Capacity Program by category: distribution substation capacity, distribution line capacity, emergent capacity, 4KV voltage conversion program, and the capacity bridging solutions program.

FIGURE 9-2
CAPITAL WALK 2024-2030
(THOUSANDS OF NOMINAL DOLLARS)



The primary drivers of the capacity program are as follows:

- PG&E forecasts significant emergent new capacity work for substation and line capacity investment to meet emerging (e.g., EV charging) needs in 2028-2030.
- Beginning in 2027, PG&E will start its 4kV conversion program, to modernize areas of the grid that utilize obsolete voltage levels and are unable to accommodate new load growth. PG&E anticipates this conversion will occur over 15-20 years.
- A new Capacity Bridging Solutions Program to help energize customers while upstream distribution capacity upgrades are awaiting completion.

While Figure 9-2 separates Distribution Substation Capacity Program and Distribution Line Capacity Program from the Emergent New Business Capacity, it is important to note that all of these programs are to provide substation capacity (MWC 46) and distribution line capacity (MWC 06). While it appears from Figure 9-2 that Distribution Substation Capacity Program and Distribution Line Capacity Program are decreasing, this is because these programs only include projects identified through the annual Distribution Planning Process (DPP). The Emergent New Business Capacity program captures the investment needed for unidentified distribution substation and line capacity projects that PG&E expects will emerge through future DPPs. Figure 9-2 above illustrates the need for the requested specific post-test year attrition.

3. Risks Addressed

PG&E's forecast for the overloaded transformer replacement program (MAT 06B) and electric engineering expense (MAT FZA) within the Capacity Program address the Electric Distribution-related Risks described in Table 9-3.[6] A summary table of the program name, risk control or mitigation identification, and CBR for this chapter is presented in Table 23-4.

The description of these activities, the cost-benefit ratio (CBR) when applicable, and why this risk mitigation, control, or foundational activity is necessary and justified is provided in Section C.

TABLE 9-3
RISKS ADDRESSED BY THIS CHAPTER

Line No.	Risk Name	Risk ID	Risk Description
1	Wildfire	WLDFR	The Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands or environment originating from PG&E assets or activities.
2	Failure of Electric Distribution Overhead Assets	DOVHD	This risk is defined as lack of remote operational functionality that may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.

[6] For additional information on these risks, see Exhibit (PG&E-4), Ch. 3.

TABLE 9-4
FOUNDATIONAL ACTIVITIES, RISK MITIGATIONS AND RISK CONTROL PROGRAMS

Line No.	MAT	Program Name	Risk Program ID(s)	CBR (2027-2030)
Risk Controls				
1	06B	Overloaded Transformers Replacement	DOVHD-C009, WLDFR-C009	0.3
Foundational Activities				
2	FZA	Annual Protection Reviews	DOVHD-C008	Foundational

Further, this chapter contains wildfire mitigations and/or controls which contribute to climate resilience because they address wildfire risk. For more information on the relationship between this General Rate Case filing and PG&E's climate resilience plans, see Exhibit (PG&E-2), Chapter 1.

B. Program Overview

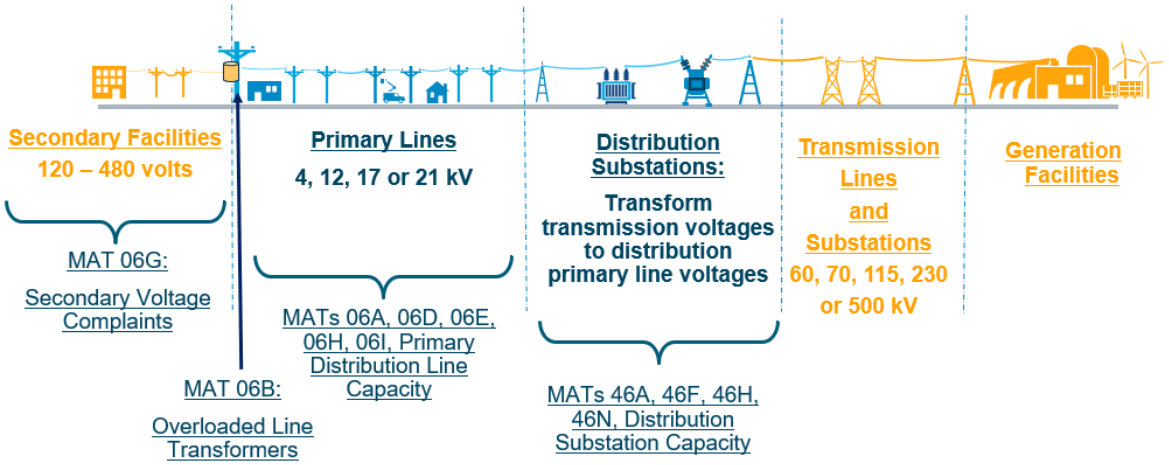
1. Planning our Distribution System

The distribution system is the portion of the electric system composed of distribution substation and primary line equipment that operate at voltages from 4,000 volts to 34,500 volts. Customer-driven expansion of the distribution system is covered by this chapter. See Figure 9-3 for a high-level diagram of the electric system and the place of distribution capacity (MWC 06 and MWC 46) within the larger system.

The secondary system is the low-voltage system comprised of voltages between 120 and 480 volts that directly serves homes and businesses. Customer-driven expansion of the secondary system is covered under the New Business section of Exhibit (PG&E-4), Chapter 10. New Business projects build the interconnection facilities needed to energize distribution-interconnected customers. This includes metering, secondary services, distribution line transformers, and distribution line extensions from the nearest available distribution facility to customer sites. Chapter 9 (this chapter) does not include secondary work with the exception of two types of secondary work unrelated to New Business: (1) overloaded service transformer replacements and (2) customer voltage complaints involving secondary voltage issues.

Transmission system lines and transmission substations controlled by the California Independent System Operator (CAISO) and generation facilities are out of scope of PG&E's 2027 GRC Exhibit (PG&E-4) (Electric Distribution).

FIGURE 9-3
PG&E SYSTEM IN RELATION TO MWC 06 AND MWC 46 WORK



As can be seen in Figure 9-3 above, distribution planning occurs at the distribution substation transformer, distribution circuit, and segments of primary lines (i.e., "line sections") that make up an entire circuit.

The key objectives of the Capacity Program are to address: (1) capacity expansion necessary to meet customer demand growth; (2) existing and forecasted equipment overload conditions; and (3) voltage and power factor compliance requirements.

Capacity needs are identified both on an annual basis through the Distribution Planning Process (DPP) and on an as-needed basis when a formal customer application for service is received and deemed complete. An application is deemed complete when it has been scoped sufficiently to identify the work type(s) the project will include (MWCs) and all customer supporting documents and information is sufficient to progress the project to the engineering and design phase. The DPP compares substation transformers and circuit load forecasts against available capacity and runs circuit simulations to determine line section capacity, voltage, and power factor deficiencies. These steps are described in detail in this section.

Although individual capital projects identified by the DPP are shown in workpapers for this chapter, it is understood that the Commission does not necessarily approve specific projects in this GRC filing. Rather, the Commission approves an overall revenue requirement to fund functional operations across the company. As time moves on, changing trends and needs may affect the scope and timing of individual projects and introduce new projects.

a. Collect Load Data

The first step in distribution planning is to forecast and plan for the load that needs to be served by the system. There are three main sources of data used in PG&E's load forecast:

1) Customer Applications for Service

A customer that wants to add load to an existing service or to establish a new service with new load submits an "Application for Service" to PG&E through the New Business Portal. Service Planning personnel will add the expected load, closest primary circuit tie-in-point, customer class, and requested in-service date to the application. Data from the load application is then ported to the DPP forecasting tool as a "known load." The Distribution Planning Engineer assigned to the affected circuit will review the known load's details. This review involves investigating the expected load and correcting it as necessary, based on actual loading of other customers of the same type and size. The Distribution Planning Engineer also verifies the tie-in point, customer class, and in-service date. The tie-in point must be on an existing circuit so that the engineer can see the impacts of the new load on the existing substation transformer, circuit, and primary line sections. If a new asset is required to serve the load, then the engineer will create a transfer in the forecasting tool that moves the load to the new asset once the project is completed. The customer class from the application for service is used to assign an hourly load profile to the new load. From that point on, the new load will appear in the forecasts for the substation transformer, distribution circuit, and

primary line section until such time as the load materializes[7] or the customer cancels the application for service.

The Distribution Planning Engineer studies the impact of the new load on various distribution assets and determines whether a capacity project is necessary. See Section B.1.d. “Identify Solutions” for more information on the solutioning process.

Larger loads typically go through the Large Load Study Process, where a formal load interconnection study is performed, and a completed report provided to the customer for signature.

Each new application for service, regardless of size, is reported annually in a confidential appendix of the Distribution Deferral Opportunity Report (DDOR) report.[8] The load, customer class, service request date, and distribution circuit are included in the report. For the 2023-2024 planning cycle, the report of known loads was provided as Appendix G.1 of the 2024 DDOR report.

2) Non-Application Loads (Pending Loads)

In the current DPP forecast, non-application loads are loads of a type where the application for service does not communicate load information to the DPP forecasting tool. These non-application loads must be manually entered into the tool by an Area Senior Engineer. These kinds of customer loads include charging loads from battery storage installations, electric vehicle pre-application loads, and load for recently constructed buildings that are energized but will add load over many years. For the 2023-2024 planning cycle, the report of non-application loads (referred to as “pending loads” in the report) was provided as Appendix G.2 of the 2024 DDOR report.

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7 Once Advanced Metering Infrastructure (AMI) metering confirms that the load has materialized, the known load adjustment is automatically removed from the forecast. From that point onward the impact of the new load becomes part of the historic loading on the substation transformer, circuit, and primary line section.

8 The DDOR report has been revised to the Distribution Upgrade Project Report (DUPR) starting with the 2025 report.

The use of non-application loads in the forecast is continuing to evolve. PG&E's practice of including non-application loads and the definition of a "Pending Load" will now be formalized through R.21-06-017 (the High DER Proceeding). Going forward, a "Pending Load" will be defined as load for which reliable information has been obtained prior to a formal application for service. This expands PG&E's use of the pending load category to include information from customer surveys and communications from governmental agencies and tribal governments. The use of Pending Loads under the new criteria is expected to be fully implemented in the 2025-2026 DPP forecast. The impact of adding Pending Loads to future forecast cycles is unknown but may help solve a key gap in proactive planning by providing better visibility into where loads will likely materialize. Through better identification of specific geographical areas of load growth, the California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) load growth can be disaggregated with more specificity. These improvements will better inform emergent capacity projects because future forecasts will include new sources of information about customer growth.

3) Organic Load Growth

Organic load growth is the term for load growth attributable to many small load increases rather than attributable to customer applications for service. Some examples of this are: an office building increasing the compressor size of their air conditioning system, a residential customer deploying an unused dryer outlet for electric vehicle charging, a restaurant purchasing a bigger freezer, a farmer increasing the size of an existing agricultural pump, or a gas station increasing the number of pumps at a service station. As these loads go online then load is increased on the circuit that serves them. Eventually the loading may surpass the circuit's capability, which creates a grid need. The need will be discovered through the annual DPP forecast, when historic loads are updated and compared against asset capabilities. If a project is required,

then the driver of the project would be said to be “organic load growth." In these cases, it is not possible to attribute the grid need to growth of a single customer.

b. Update the Annual DPP Forecast

While distribution load forecasts are dynamic because load data changes as new applications for service or other non-application load information is received, PG&E uses the most recent snapshot in time of that data to inform and develop its annual Distribution Planning Process (DPP) forecast. The following section describes other information that is updated annually as part of the DPP to create distribution loading forecasts for all substation transformers, circuits, and primary line sections.

In the winter of each year, PG&E’s distribution forecasts are updated to include the following information:

1) CEC IEPR Hourly Load Forecasts: IEPR forecasts provide a system-level PG&E load for each hour of the year for each year of the forecast. PG&E turns these cumulative load totals into annual incremental load growth by subtracting the hourly load in one year from the hourly load in the subsequent year. Transmission-served load growth (such as transmission-connected customers and municipal utilities served from the PG&E transmission system) and the growth from known load applications and other non-application loads are deducted from the total CEC system load growth forecast. The resultant load growth is distributed out by customer class (residential, industrial, commercial, and agricultural) and is then allocated to PG&E’s distribution circuits using geospatial analysis.

The forecasts provided in the 2024 Grid Needs Assessment (GNA) report utilized the 2022 CEC IEPR forecast,[9] which was the most recently adopted IEPR at the time of forecast creation.

2) CEC IEPR Distributed Energy Resources (DER) Hourly Forecasts: IEPR DER forecasts provide the system-level PG&E DER impact for

[9] California Energy Demand Forecast Update, 2022-2035, available at: <https://efiling.energy.ca.gov/GetDocument.aspx?tn=248358> (accessed April 8, 2025).

each hour of the year for each year of the forecast. PG&E turns these cumulative DER totals into annual incremental DER growth by subtracting the hourly DER total in one year from the hourly DER total in the subsequent year. DERs in the IEPR include solar photovoltaics (PV), residential and non-residential energy storage discharge, energy efficiency, fuel substitution, and electric vehicles (EV) (including forecasts for residential Level 1, Residential Level 2, fleets, Public Level 2, Workplace Level 2, and urban DC fast charging). Variables used to allocate incremental DER growth to circuits include consumption by customer class, existing PV adoption, local DER ordinances, DER adoption potential by customer, EV facilities needed to serve mobile loads, and many other factors specific for each type of DER.[10]

3) Advanced Metering Infrastructure (AMI) Customer Data: AMI data is collected on an hourly basis from the previous 12 months. Updating historic load data allows the forecast starting point to reflect changing trends in customer energy usage, including increased customer load due to electric vehicles and air conditioning, decreased customer load from energy conservation, energy storage, and PV adoption, and customer load shifting as a reaction to changing rates. The benefits of using aggregated AMI data instead of circuit-level Supervisory Control and Data Acquisition (SCADA) data is that AMI data eliminates sources of

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10 In the current DPP forecast, load shifting, or the change in time of peak electricity use from its present hour to a different hour is accounted for via load and DER growth included in the CEC IEPR hourly load forecast. As can be seen from the recorded CAISO system peak from 1998 to 2024 <https://www.caiso.com/Documents/CaliforniaISOPeakLoadHistory.pdf>, the hour of peak load began shifting from 2:30pm in 1998 to 5pm in 2013 and 6pm in 2019. Most of this shift can be attributed to PV adoption. Since then, the time of peak load has been stable, never landing outside the 4pm and 6pm window which represents the time when solar production declines and then disappears. Future PV adoption will not affect the hour of peak because it already occurs at a time of minimal PV production. Other technologies, though, such as the adoption of energy storage which discharges during the early evening hours, may shift the time of both system and local peaks. The 2022 IEPR does not show such a shift in the time of peak (managed net peak in 2025 for PG&E's service area is between 6pm-7pm and the 2035 peak is also between 6 p.m. to 7 p.m.). Future IEPR forecasts, however, may include such a shift.

data errors such as abnormal circuit switching and short-duration load spikes. This is because the aggregated AMI data always reflects the load of the circuit in its normal configuration, even at such times as the circuit itself is in an abnormal configuration. SCADA data, on the other hand, always reflects the load served by the circuit, even when in an abnormal configuration such as serving no load at all.

4) Hourly Weather Data for Weather Stations: The weather data is used to create load profiles.

5) Typical Load Year (TLY) Hourly Base Load Profiles for Each Circuit: PG&E associates each customer service point with a circuit in the circuit's normal configuration. AMI historical loading data is updated for each service point. The resulting aggregate loading is a multi-year hourly load profile for each circuit. A regression is then created using weather data and AMI meter loading for each hour. This regression is used by the weather normalization algorithm to generate a base hourly load profile that represents loading for a year with typical weather.

6) Typical Load Year (TLY) Hourly Base Load Profiles for Each Substation Transformer: Each distribution circuit is mapped to the substation transformer that serves it. The aggregate hourly loading for these circuits is used to obtain hourly transformer bank loading.

7) Completed Changes to Normal Circuit Configurations: Circuit reconfigurations cause changes to the mapping of customers' service points to circuits. It is important that the new forecast capture any movement of load from one circuit to another.

8) Completed Capacity Projects and Updated Equipment Ratings: Capacity projects can add new assets or change the capability of existing assets. If these changes are not captured in the forecast, then the forecasted asset loading will be compared against an incorrect asset capability, possibly resulting in the generation of solutions that are not needed.

9) Other Economic, Geographic, and Demographic Data: This data is used to disaggregate both the CEC IEPR load and CEC IEPR DER

growth to circuits. PG&E has twelve categories of spatial growth, which include trends like energy efficiency, solar PV adoption, and Level 1 residential EV charging. PG&E's maximum spatial growth in each category is set by the CEC IEPR forecast.

When all of the above updates are incorporated into the forecasting tools, asset loading forecasts are then created. Asset loading forecasts include a 12-year forecast of substation transformers and circuit loading and a 3-year forecast of primary line section loading.

c. Identify Grid Needs

From late winter to early spring, the Distribution Planning Engineers review comparisons between the asset loading forecasts and asset capabilities to determine areas of grid needs. When forecast load exceeds 100 percent of the thermal rating on any individual piece of equipment, a normal capacity deficiency is identified. During the cycle the engineers review the underlying data that provides asset capabilities and loading and make any necessary updates and corrections.

For the 2023-2024 planning cycle, the substation transformer and distribution circuit capabilities and load forecasts were provided as Appendix E of the 2024 GNA report.[11] The aggregated line sections with loading, voltage, or power factor needs were provided as Appendix G of the 2024 GNA report.[12]

d. Identify Solutions

1) Load Transfers

Prior to proposing equipment upgrades, to the extent possible, overload or capacity deficiencies and low-voltage conditions are mitigated through available system reconfiguration, such as

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11 PG&E 2024 Grid Needs Assessment (GNA), Appendix E: GNA Results – Bank & Fender Capacity Needs (Sept. 5, 2024), available at: <http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=805928> (accessed April 8, 2025).

12 PG&E 2024 Grid Needs Assessment (GNA), Appendix G: GNA Results – Line Section Capacity and Voltage Needs (Sept. 5, 2024), available at: <http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=805930> (accessed April 8, 2025).

switching between substation transformers and circuits. These reconfigurations are known as “load transfers.”

Sometimes these load transfers can be done without circuit modifications. More often, they involve the creation of new ties between circuits or upgrades of existing conductors to handle the movement of load. If a load transfer is proposed between circuits with different operating voltages, then proper voltage transformation equipment will be required. If any of the following operational issues are created by a proposed load transfer, then a capacity increase is evaluated in lieu of the transfer given the following criteria:

- Circuits with customer counts greater than 6,000;
- Circuit loads greater than 600 Amperes; or,
- Circuit loads greater than 75 percent of emergency capacity.

If the forecasted overload is larger than can be mitigated by load transfers between existing facilities or if no load transfers are available, then solutions involving primary line section upgrades are studied.

2) Primary Line Section Upgrades

If available switching options cannot produce load transfers to eliminate a forecasted overload, Distribution Planning Engineers look at creating additional capacity on existing circuits. This type of upgrade can include replacing overhead or underground conductor with larger conductor, conversion to a higher voltage, and the installation of voltage regulation or power factor correction equipment. The purpose of these upgrades is to allow the existing circuit or adjacent circuits to carry additional load. If the circuit or adjacent circuits are already at their maximum capability or if the forecasted overload is larger than can be mitigated by creating additional capacity on the existing circuit or adjacent circuits, then solutions involving a new circuit are studied.

3) New Circuits

If primary line section upgrades cannot provide sufficient capacity to serve new load, then a new circuit is required. This new

circuit may be extended from the nearest substation to the new load or from an adjacent substation, depending on the availability of substation transformer capacity as well as the length of circuit required from each substation.

A new circuit requires its own protective element inside the substation which is typically a circuit breaker. Distribution circuit breakers are connected to substation transformers either by means of an outdoor distribution bus or a switchgear building. Switchgear buildings are employed when space inside a substation is too limited to install an outdoor distribution bus.

Outside of the substation, a new circuit requires a new overhead or underground circuit outlet, new overhead or underground mainline conductor, and line equipment such as switches, interrupters, reclosers, capacitor banks, voltage regulators, etc. Rarely is a new circuit entirely comprised of new conductor. More commonly a new circuit may be composed of new primary line which is extended to reach existing primary line. The existing line may require replacement with larger conductor to serve forecasted load. Design decisions impacting the length and the cost of the new circuit include:

- Determining the route of the circuit based on the purpose of the circuit:
  - Does it need to serve new load? Where is the new load located?
  - Does it need to be built to take load off a second circuit so the second circuit can serve new load?
  - Does it need to tie to other circuits to provide operational capacity and prevent a large number of customers or a large amount of load from experiencing extended outages?
- Identifying sections of existing circuits that should be incorporated into the new circuit;
- Accounting for any high fire threat areas;
- Ensuring as much conductor as possible is safely accessible by utility workers;

- Identifying routes that can utilize existing franchise rights;
- Accounting for any new facilities on private property;
- Accounting for any double-circuit overhead construction where new line is to be built under existing transmission and/or distribution lines;
- Accounting for routes that require significant permitting;
- Identifying existing freeway or railroad crossings that can be used rather than installing new crossings;
- Identifying sensitive habitat areas;
- Identifying areas that have rules against the installation of new distribution poles; and,
- Identifying areas that require new utilities to be built underground and designing accordingly.

4) Replacing Substation Transformers

If an existing substation transformer does not have sufficient capacity to serve new load, then reconfiguration is studied. Prior to proposing substation upgrades, to the extent possible, capacity deficiencies are mitigated through available substation reconfiguration, such as swapping circuits between substation transformers. Occasionally a substation upgrade can be avoided by moving a circuit from a heavily loaded substation transformer to a more lightly-loaded substation transformer within the same substation. This transfer often requires either a substation bus reconfiguration or the reconfiguration of circuit outlets just inside or outside the substation.

After available substation reconfigurations are exhausted or if they cannot mitigate a forecasted overload, Distribution Planning Engineers look at creating additional capacity by replacing existing substation transformers with a larger size unit. This larger size transformer may require a neutral reactor and may result in the upgrade or replacement of the existing substation control building, expansion of the substation Spill Prevention Containment and Countermeasure (SPCC) oil retention system, and upgrades to the substation ground grid. If the substation transformer is already as

large as possible, an additional (new) substation transformer would be installed.

5) Installing New Substation Transformers

If existing substation transformers are already as large as possible, a new substation transformer would be installed. The addition of the new transformer will require a low voltage distribution bus and new distribution circuit breakers and may result in the upgrade or replacement of the existing substation control building, expansion of the substation Spill Prevention Containment and Countermeasure (SPCC) oil retention system, upgrades to the substation ground grid, and expansion of the substation yard area and perimeter fence.

Some substation upgrades related to the installation of new substation transformers belong to the transmission system and are not CPUC-jurisdictional. As such, these costs are not part of this GRC filing. When a new substation transformer is installed at a substation, a new transmission protection element or elements may be required, depending on the existing configuration of the transmission bus. If the number of transmission lines and transformers exceeds certain criteria then the transmission bus will require upgrade to a different, more reliable, configuration. These types of upgrades are beyond the GRC.

6) Creating New Substations

If existing transformers in the area of concern are at maximum size and no new transformers can be added, then the addition of a new substation to the system is studied. Design decisions that affect the siting of new substations include:

- Size of site: 5 to 10 acres is the typical minimum size requirement, depending on transmission supply voltage and the number of transmission lines that will eventually connect to the substation;
- Proximity of site to existing transmission lines;
- Proximity of site to new loads;

- Identifying locations that will require freeway or railroad crossings for majority of new distribution circuits;
- Identifying projects where the larger project undergoing California Environmental Quality Act (CEQA) review requires a proposed substation to serve the site;[13]
- Identifying environmentally sensitive areas; and,
- Identifying areas where transmission capacity is limited.

7) Other Solutions

Other feasible solutions that meet voltage, operational and capacity needs may also be studied. This can include energy storage, DERs, and dynamic and demand flexibility rates.

For the 2023-2024 planning cycle, Planned Investments were provided as Appendix A.1 of the 2024 DDOR report.[14] Planned Solutions were provided as Appendix A.2 of the 2024 DDOR report.[15] "Planned Investments" include all proposed distribution planning solutions that are currently funded within the 5-year planning horizon, including projects funded through interim rate recovery in the Energization Capacity New Business Interim Memorandum Account, authorized in D.24-07-008. "Planned Solutions" are proposed distribution planning solutions for which funding within the current planning horizon is not currently available.

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[13] Projects are required by the California Environmental Quality Act (CEQA) to include offsite utility improvements in their environmental review if they constitute "the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment." California Code of Regulations, title 14, § 15378(a).

[14] PG&E 2024 Distribution Deferral Opportunity Report (DDOR), Appendix A.1: Planned Investments (Sept. 9, 2024), available at: <http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=806448> (accessed April 8, 2025).

[15] PG&E 2024 Distribution Deferral Opportunity Report (DDOR), Appendix A.2: Planned Solutions (Sept. 9, 2024), available at: <http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=806449> (accessed April 8, 2025).

e. Identify Applicable Bridging (Interim) Solutions for Customer Energization

Bridging solutions are temporary measures that allow a customer full or partial energization of new load earlier than otherwise would be possible because of capacity limitations and timelines for infrastructure upgrades.

During the customer load application process, Distribution Planning Engineers review the customer-requested load, align the load magnitude and hourly load profile with typical demand for similar facilities, and compare the load against available substation and distribution line capacity. In cases where the new load exceeds grid capacity and the grid need cannot be addressed prior to the customer's requested in-service date, discussions are initiated with the customer regarding load needs and flexibility. As appropriate, a staged energization is discussed with the customer and/or flexible service connections are considered. As part of reviewing the customer's application for service, Distribution Planning Engineers also study and identify the infrastructure upgrades that will allow the customer to be fully energized. These upgrades then go through a scoping and prioritization process.

PG&E currently has two primary standard bridging solutions: (1) load limit letters and (2) flexible service connections. Load limit letters are provided to customers when temporary load limits are a condition of initial energization. The limits can be static, seasonal, or based on time of day. Flexible service connections (FlexConnect) provide customers with day-ahead hourly load limits that use PG&E's Distributed Energy Resources Management System (DERMS) to connect to the customer's energy management system. These limits apply until capacity upgrades are completed. One example of FlexConnect in use is EV charging for a commercial semi-truck fleet in Fresno. Implemented in November 2024, the use of FlexConnect has been able to broaden the winter nighttime charging window for the trucks beyond that which could have been stated in a load limit letter. For a full discussion of Bridging Solutions, please see PG&E's Bridging

Strategies Compliance Report.[16] For more information on PG&E's FlexConnect experience, please see PG&E's OpFlex Pilot Report.[17]

f. Estimate Costs

Based on project alternatives being evaluated, the area planning groups then develop high-level project cost estimates. For most projects, Distribution Planning Engineers develop costs using either estimates of specific equipment and unit costs for work required, or historical costs from completed projects. Unit costs are presented in the workpapers supporting this chapter.[18]

g. Project Approval and Prioritization

After a Distribution Planning Engineer proposes a project, supervisor approval is required to proceed with the project. The supervisor reviews the project with the engineer to be sure that forecast updates have been made and that no relevant project alternatives have been missed.

Currently, distribution capacity is prioritized by PG&E's Electric System Planning & Reliability team, with projects falling into three priorities:[19]

- Priority 1: Top priority is given to capacity projects that are: (1) being done in conjunction with emergency or asset health projects, (2) near-completion, (3) public safety-related, or (4) addressing heightened outage or safety risk.
- Priority 2: Second priority is given to projects that connect waiting customers. These projects are scored against each other based on the customer requested in-service date, whether this project serves emergency or critical services in the community, and any

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16 See PG&E's Bridging Solutions Strategies Compliance Report (Dec. 16, 2024), pursuant to R.21-06-017 and R.24-01-018 (not consolidated).

17 See PG&E's OpFlex Pilot Report (Feb. 28, 2025), pursuant to D.21-06-002 and Resolution E-5260 as part of R.17-07-007.

18 Exhibit (PG&E-4), WP 9-72, Workpaper Table 9-18.

19 R.21-06-017_PG&E Responses to Amended Scoping Memo Appendix A, p. 16.

commitments made to these communities, elected officials, or the CPUC.

- Priority 3: Third priority is given to projects that address actual and forecasted overloads but that do not currently have waiting customers. In this case, assets may be loaded beyond their capacity due to increased load demands from existing customers, or assets may be forecast to be loaded beyond their capacity based on organic load growth. These projects benefit customers by creating capacity in areas of growth so that the next customer that provides an application for service can be energized without the delays associated with capacity upgrades. In the case of assets that are presently loaded beyond their capacity, no new loads that exacerbate the existing overload can be served until capacity investments are completed. Priority 3 projects may be pushed into Priority 2 if loading above capacity is expected to be severe, or if a new business application is received which cannot be served due to existing asset loading.

h. Identify LCFS-Funded Projects

The Low Carbon Fuel Standard (LCFS) Capacity Pilot[20] provides $20 million in 2025 to fund distribution capacity projects that support EV charging, in lieu of recording those costs to traditional ratemaking mechanisms such as the GRC and the Electric Capacity New Business Interim Memorandum Account (ECNBIMA) authorized in D.24-07-008. This pilot, implemented in 2025, will select projects using CARB and CPUC-defined criteria (such as projects that support energization of medium- and heavy-duty EV charging stations and benefit a Priority Community) and the costs for those projects will not be recorded for recovery in this GRC or the ECNBIMA. As work progresses on eligible capacity projects and capital costs are incurred, LCFS funding will be transferred from the LCFS subaccount within the Greenhouse Gas Revenue Balancing Account (GHGRBA), to offset capital costs and the

20 CPUC Resolution E-5361 (January 30, 2025), p. 6 and Advice Letter (AL) 7071-E and AL 7071-E-A.

future book value (and rate base) of the asset. Per Resolution E-5361, PG&E will work with Energy Division and the CPUC-approved auditor, Ernst and Young, to undertake any reporting modifications needed to ensure the pilot activities and impacts are tracked in a detailed manner and reported clearly and transparently.[21]

i. Report Results

To provide transparency into the assumptions and results of PG&E's annual DPP, several public reports are published each year. Grid needs from distribution load forecasts are reported in the Grid Needs Assessment (GNA) report for the following four types of needs: distribution capacity, voltage support, reliability (back-tie), and resiliency (microgrid). Planned Investments and Planned Solutions are identified in the Distribution Deferral Opportunity Report (DDOR), replaced by the Distribution Upgrade Project Report (DUPR) starting with the 2025 report.

GNA and DUPR reports are updated each year based on changes from updated inputs and new regulatory requirements. Capacity deficiencies and projects in the 2027 GRC were identified during the 2023-2024 forecasting process, which used the 2022 CEC IEPR system forecast. These deficiencies and projects were the basis for the 2024 GNA and DDOR reports published by PG&E on September 5, 2024.

Each new year brings a new forecast cycle and new information to the forecast. Since the time of the 2023-2024 DPP forecasts, additional applications for service were received, new AMI meter data was uploaded, the 2023 IEPR was adopted, and new projects are being identified as part of the 2024-2025 forecasting process. These newly-identified projects will be listed in the 2025 GNA report to be issued by PG&E on August 15, 2025.

The year following the 2024-2025 cycle is expected to provide even greater changes to the DPP. The evolution of "Pending Loads" is expected to occur within Rulemaking 21-06-017 (High DER) which will

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21 *Id.*, at p. 25, Ordering Paragraph (OP) 5.

define and formalize new categories and treatments of pending loads in the 2025-2026 planning cycle. In addition, the 2024 IEPR will be approved and available for use in the 2025-2026 planning cycle. Preliminary versions of this IEPR forecast show increased transportation electrification, building electrification, indoor cultivation, and data center loads, and decreased PV growth forecasts.

2. Changes Since the 2023 GRC

Since the 2023 GRC, California legislation and CPUC regulatory mandates have been enacted that impact the planning and engineering of the electric system; change how future electric distribution system forecasts are derived; and increase the number and timing of new electric distribution capacity projects needed each year. High-level changes include the following:

a. Powering Up Californians Act

The Powering Up Californians Act was enacted in 2023. It finds that to:

> …meet these decarbonization goals and federal, state, regional, and local air quality and decarbonization standards, plans, and regulations, the state's electrical distribution systems must be substantially upgraded, new customers must promptly connect to the electrical distribution system, and existing customers must have their service level promptly upgraded.[22]

The Act requires the Commission to establish criteria for timely energization service along with minimum and maximum energization timelines for utilities[23] and correspondingly authorizes electrical corporations to request a ratemaking mechanism to fund energization work that exceeds imputed funding authorized in its general rate case subject to an annual cost cap.[24] The Act also made explicit requirements for distribution planning forecasting that directly impact PG&E's request for its Capacity Program in this GRC. The Act requires utilities to include the following in its distribution load forecasts:

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[22] Pub. Util. Code § 932(a)(2).

[23] Pub. Util. Code § 933 and 934.

[24] Pub. Util. Code § 937.

a) Federal, state, regional, and local air quality and decarbonization standards, plans, and regulations.
b) The transportation and building electrification policies of state law.
c) State agency, local agency, and local government plans and requirements related to housing, economic development, critical facilities, transportation, and building electrification.
d) Projections of load that exceed forecasts provided by the California Energy Commission.[25]

b. Energization Timelines OIR (R.24-01-018)

Pursuant to the Powering Up Californians Act described above, the Commission established average and maximum energization timelines. In Decision 24-09-020, the Commission sets the following reporting requirements for capacity project maximum timelines:

1) 1.9 years for New Circuits and Distribution Line Upgrades;
2) 2.8 years for Substation Upgrades; and
3) 8.9 years for New Substations.[26]

The above timelines assume that capacity projects will be funded as soon as they are identified. This requires that sufficient emergent funding be made available to begin projects as soon as future customer applications are received, across all the years of the GRC.

c. High DER Future Proceeding and Improvements to Distribution Planning

In the High DER Future Proceeding (R.21-06-017), the Commission adopted requirements that will change future DPP forecasts and how the forecasts are derived, including forecasts for years covered by the 2027 GRC. These changes will likely create additional capacity projects because future forecasts will be informed by new sources of information about customer growth. Some of these changes include:

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25 Pub. Util. Code § 936.

26 D.24-09-020 (September 17, 2024) p. 47, Table 5: "Large Electric IOU Maximum Timelines for Upstream Capacity Upgrade Projects."

1) The inclusion of pending loads in distribution forecasts, beginning in the 2026-2027 forecast cycle;[27]
2) The use of scenario planning, beginning in the 2025-2026 forecast cycle;[28]
3) Expansion of the planning horizon to 10 years;[29]
4) The use of bridging (interim) strategies to better accommodate energization requests that require system upgrades;[30] and
5) Allowing utilities to update GRC testimony due to emergent needs or changing forecasts. Later year forecasts may be submitted as testimony or supplemental testimony in a manner that does not ultimately delay the proceeding.[31]

The changes above will help solve a key gap in proactive planning by providing better visibility into location, timing, and magnitude of customer growth. Identification of where loads will likely materialize will help develop emergent capacity forecasts.

d. Authorization of Energization Ratemaking Mechanism in D.24-07-008

Pursuant to the Powering Up Californians Act, PG&E requested authorization for a ratemaking mechanism for energization investments above GRC adopted amounts. In D.24-07-008, the Commission adopted the Energization Capacity New Business Interim Memorandum Account (ECNBIMA) which provides interim rate relief for projects placed in service between January 1, 2024 and December 31, 2026 that exceed imputed GRC amounts, subject to annual caps and reasonableness review.[32]

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27 D.24-10-030, p..73.

28 *Id*., at p. 58.

29 *Id*., at p. 53.

30 *Id*., at p. 92.

31 *Id*., at p. 103.

32 D.24-07-008, pp. 95-96, Ordering Paragraph 24 and 25 also requires PG&E to report on its Distributed Energy Resources Management System (DERMS), flexible service connection pilot, and demand and dynamic flexibility rates. This is provided in Exhibit (PG&E-4), Ch. 22.

PG&E has been able to execute work above 2023 GRC imputed adopted amounts due to D.24-07-008 and the creation of a new memorandum account (ECNBIMA) to track such costs.

e. Electric Vehicle Policy

As discussed further in Chapter 10 (Section B), California policy is accelerating transportation electrification, not only for light duty EVs but also non-residential fleet and medium and heavy-duty vehicles where loads can be larger and energization timelines longer. Grid infrastructure needed to support vehicle electrification is a prerequisite to the realization of these policy goals. Significant work will be required to reach the state's build-out of charging infrastructure over the next several years. Without adequate and timely availability of new grid capacity, building the infrastructure to meet these transportation electrification policies will not be possible.

C. Electric Distribution Capacity, Engineering and Planning Forecast

1. Distribution Substation Capacity Program (Capital MWC 46)

a. Overview

The Distribution Substation Capacity program consists of upgrades to various pieces of distribution substation equipment that are forecast to have a capacity deficiency that cannot be mitigated by load transfers and substation reconfigurations.

Normal Capacity Deficiencies (MAT 46A) include projects inside a substation that address deficiencies caused by organic load growth (see Section B.1). Normal capacity deficiencies are identified based on peak load forecasts compared to normal capacity ratings of the various pieces of substation equipment. Addressing existing and forecasted overloads caused by organic load growth is critical to prevent equipment damage and customer outages. Overloaded substation transformers have a higher risk of failure than normally loaded transformers due to heating of the internal transformer components. Overheating is especially problematic for transformer insulation and oil. Overheating of silicone

oils causes degradation of fluid and generation of gases.[33] Excessive heating caused by sustained overloads or loss of cooling…degrade[s] insulation.[34] Substation transformer failures can result in lengthy outages for a large number of customers, decreasing customer productivity, impeding customer ability to charge vehicles, and possibly affecting public safety due to traffic signal outages and absence of streetlights. Normal Capacity Deficiency projects also benefit customers by creating capacity in areas of growth so that the next customer that provides an application for service can be energized without the delays associated with capacity upgrades.

Emergency and Operational Capacity (MAT 46F) includes distribution substation work to address substation emergency capacity deficiencies and work that reduces the number of customers on a circuit to no more than 6,000 and circuit loading to a maximum of 600 amperes (amps). Circuits without sufficient ties to other circuits, with 6,000 or more customers per circuit, or with a load of more than 600 amps, pose two issues: (1) a large number of customers are affected when an outage occurs due to a circuit breaker opening; and (2) typical loading limits on adjacent circuits could hinder the ability to reconfigure highly-loaded circuits. These issues negatively affect service reliability in both customer outage frequency and duration. Projects that create emergency capacity at substations can reduce outage durations by increasing the ways that unserved load can be moved from de-energized substation transformers and distribution circuits to energized ones.

New Business-Related Capacity (MAT 46H) includes projects which address capacity deficiencies for customer load increases. Customers submit Applications for Service for new facilities as well load increases at existing facilities. PG&E's local area planners forecast the need for these projects, based on these requests for service. Completion of

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33 U.S. Department of the Interior, *Transformers: Basics, Maintenance, and Diagnostics* (April 2005) p. 168.

34 U.S. Department of the Interior, *Transformers: Basics, Maintenance, and Diagnostics* (April 2005) p. 200.

these projects is important to customers who require service so that they can open their establishments, move into their homes, or begin their manufacturing. Energization delays can result in loss of customer productivity, inconvenience, and possible loss of income. Delays can also make it challenging for customers and local governments to meet the state's building electrification and transportation electrification goals, and lack of funding for these activities especially challenges PG&E's ability to meet its energization timeline requirements established in D.24-09-020.

Land Purchases for New Distribution Substations (MAT 46N) consists of land purchases in support of building new substations that are needed to increase distribution system capacity. Larger projects are required by the California Environmental Quality Act (CEQA) to include offsite utility improvements in their environmental review if they constitute "the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment."[35] These land purchases constitute the first step in creating capacity in areas where forecasted growth exceeds the ability of existing substations to serve new customers or increased load to existing customers. These new substations are often a critical component of electrical supply to larger industrial customers and/or mixed developments. As such, funding for land acquisition to start the process based on best-available forecasts can avoid energization delays. Energization delays can result in loss of customer productivity, inconvenience, possible loss of income, and challenges in meeting the state's building electrification and transportation electrification goals.

b. Forecast

Table 9-5 shows recorded and forecast spend for the types of substation capacity work described in the previous section. The table does not include emergent capacity work or 4 kV conversion work forecasts which are provided in Sections C.3 and C.4.

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35 Cal. Code of Regs., tit. 14, § 15378(a).

TABLE 9-5
DISTRIBUTION SUBSTATION CAPACITY (MAT 46A, 46F, 46H, 46N)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted					Forecast					
			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	46A	Normal Capacity Deficiencies(a)	$6,359	$9,128	$18,170	$18,204	$20,546	$19,722	$42,110	$41,133	$34,290	$28,840	$5,910
2	46F	Emergency and Operational Capacity	11,942	17,399	9,634	2,547	2,930	14,200	9,438	11,752	16,500	9,910	4,320
3	46H	New Business-Related Capacity(b)	17,226	27,208	32,493	46,817	76,589	154,877	186,963	152,954	88,670	61,750	54,440
4	46N	Land Purchases for New Distribution Substations	46	7	120	(286)	173	–	–	4,602	8,700	7,550	9,975
5		Total	$35,574	$53,741	$60,417	$67,283	$100,240	$188,799	$238,511	$210,441	$148,160	$108,050	$74,645

(a) Does not include 46A forecast for 4 kV Conversion Program (Section C.4).

(b) Includes only identified 46H projects. Does not include 46H forecast for Emergent Capacity (Section C.3).

The forecast for Normal Capacity Deficiencies (46A), Emergency and Operational Capacity (46F), New Business-Related Capacity (MAT 46H), and Land Purchases for New Substations (46N) is based on identified projects developed as part of the annual DPP described in Section B.1. These projects are individually listed in this chapter's workpapers.[36] Project costs for more mature projects come from actual designs and cost estimates. For newly-identified projects, standard unit costs[37] were used to establish the rough project costs shown in workpapers. Identified projects required to mitigate capacity deficiencies were reported in the 2024 DDOR reports. Any 2027 forecast increases compared to 2024 recorded are primarily driven by new projects required to mitigate forecasted overloads and to energize new customers.

PG&E is projecting a year-over-year decrease after 2027 for the Distribution Substation Capacity Program, shown in Table 9-5 above. As such, simple escalation described in Exhibit (PG&E-11) for the attrition years (2028-2030) is not appropriate. PG&E requests that each attrition year for this program be separately authorized in the GRC as presented in Table 9-5.[38]

2. Distribution Line Capacity Program (Capital MWC 06)

a. Overview

The Distribution Line Capacity Program includes capacity expansion work outside the substation fence. These projects provide capacity to energize customers or to address specific capacity deficiencies or overload conditions. Some projects address voltage conditions outside of Electric Rule 2 criteria on distribution lines and equipment. PG&E performs this work to prevent overloads and avoid equipment damage and/or customer outages when mainline protective equipment de-energizes overloaded primary distribution lines. Equipment damage

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36 Exhibit (PG&E-4), WP 9-19, Workpaper Table 9-12.

37 Exhibit (PG&E-4), WP 9-72, Workpaper Table 9-18.

38 Attrition adjustment policies and mechanics, including discrete expense and capital programs, are addressed in Exhibit (PG&E 11), Chs. 1, 2, and 3.

and failure can result in lengthy outages for customers, decreasing customer productivity, preventing customers from charging electric vehicles, causing inconvenience and possible loss of income.

Circuit Projects Associated with Substation Work (MAT 06A) encompasses installing and/or replacing overhead conductor and underground cable associated with new substation transformers and circuits. These projects address existing and forecasted overloads caused by normal load growth and are critical in preventing equipment damage and customer outages. These projects also benefit customers by creating capacity in areas of growth so that the next customer that provides an application for service can be energized without the delays associated with distribution line upgrades. The substation work associated with these line work projects is described in Section C.1.a and includes Normal Capacity Deficiencies (46A) and Emergency and Operational Capacity (MAT 46F).

Overloaded Line Transformers (MAT 06B) corrects capacity deficiencies on distribution line transformers (also called service transformers), either by replacing the overloaded line transformer with a larger transformer, or by adding an additional transformer and transferring load. PG&E identifies line transformer projects by overload reports using SmartMeter™ data.

Replacing overloaded service transformers prior to failure is important because overloaded transformers have a higher risk of failure than normally loaded transformers due to heating of the internal transformer components. Overheating is especially problematic to transformer insulation and oil. Overheating silicone oils cause [fluid] degradation and generation of gasses[39] and excessive heating caused by sustained overloads or loss of cooling degrade[s] insulation.[40] Transformer failures can result in lengthy outages for customers, decreasing customer productivity, impeding customer ability to charge

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39 U.S. Department of the Interior, *Transformers: Basics, Maintenance, and Diagnostics* (April 2005) p. 168.

40 U.S. Department of the Interior, *Transformers: Basics, Maintenance, and Diagnostics* (April 2005) p. 200.

vehicles, causing inconvenience, and resulting in possible loss of income. In addition, overloaded transformer replacements benefit customers by creating additional capacity so that the next customer that provides an application for service on that service transformer can be energized without the delay associated with service transformer replacement.

Replacing overloaded service transformers prior to failure is a control to the Failure of Electric Distribution Overhead Assets (DOVHD) and Wildfire (WLDFR) risks.[41] As described above, overloaded transformers cause overheating within the transformer equipment, which may also lead to equipment failure and customer outages. It some circumstances, the overheating may cause an ignition. Accordingly, proactive replacement of overloaded transformers prior to failure controls these risks. PG&E is currently tracking over 67,000 overloaded service transformers in the system,[42] but because the CBR for this activity is low, PG&E is limiting transformer replacements to between 400 and 488 transformers per year. Overloaded transformer replacements are prioritized on a system-wide basis, based on the percentage (%) of overloading.

Circuit Reinforcement (MAT 06D and MAT 06E) encompasses installing and/or replacing underground cables, overhead conductors, line switches, protective devices, voltage regulating devices, energy storage, and other feasible solutions to meet voltage, operational and capacity needs. MAT 06D is for smaller projects, typically for those that cost less than $100,000. MAT 06E involves the same type of work as MAT 06D but generally has a larger scope. Both 06D and 06E projects address existing and forecasted overloads and voltages outside limits that are caused by normal load growth. This work is critical to prevent equipment damage and customer outages. It also has the benefit of creating capacity in areas of growth so that the next customer seeking service can be energized without the need for capacity upgrades.

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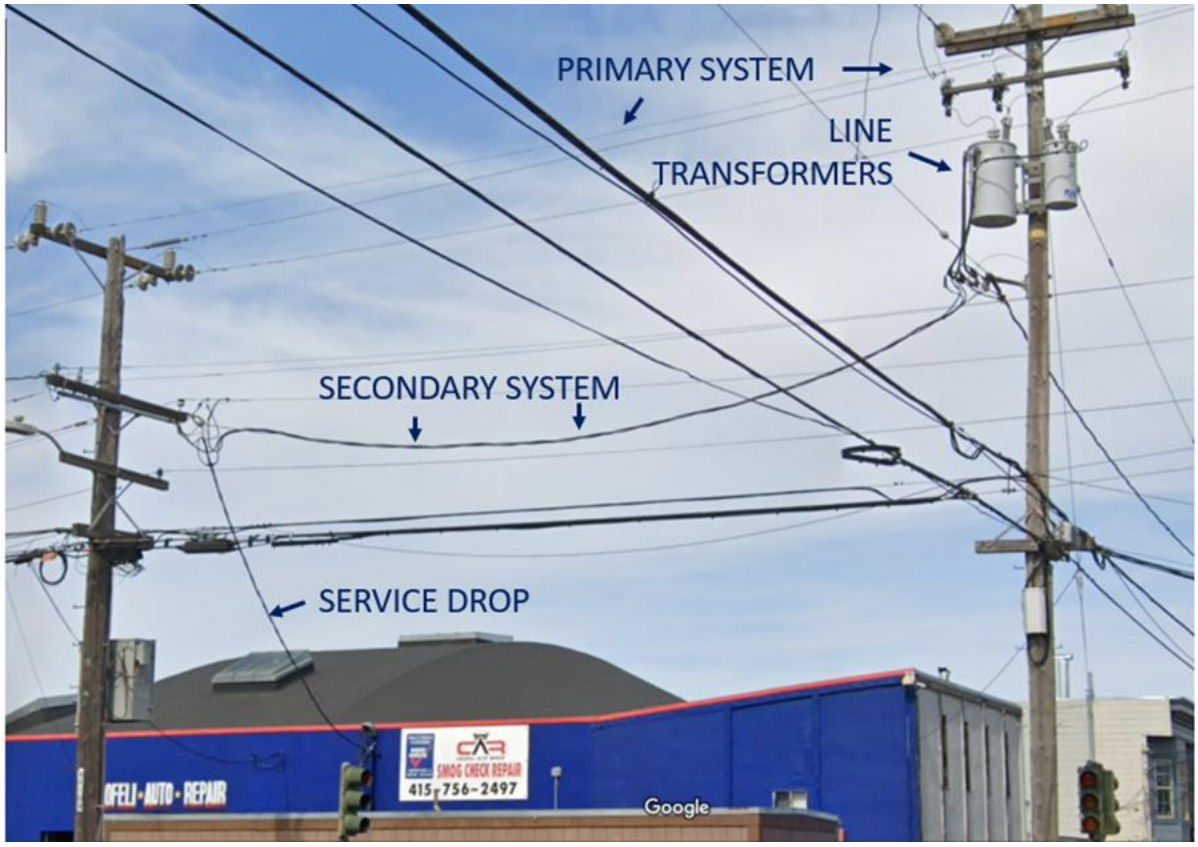
41 For definitions of these risks, see Table 9-3.

42 Exhibit (PG&E-4), WP 9-71, Workpaper Table 9-17, line 20.

Voltage Complaint Projects Involving Secondary Distribution (MAT 06G) typically consists of adding or upgrading : (1) existing service transformers; (2) secondary distribution conductors; and/or (3) secondary service wires, also known as “service drops.” PG&E conducts this work to comply with the voltage requirements of Electric Rule 2. PG&E typically identifies this work from customer complaints. PG&E then sets a recording voltmeter at the service delivery point to confirm the problem. If a voltage problem is identified, PG&E personnel evaluate potential solutions and determine a cost-effective remedy. The work to ensure proper voltage at the customer meter is essential to the operation of customer equipment. Motors will experience burnout if voltages are beyond design tolerances and many motor controllers will not allow motors to function unless voltage is within these tolerances. Solar-electric generation systems will not generate power if voltages are above certain pre-set inverter thresholds.

FIGURE 9-4
EXAMPLE OF TYPICAL EQUIPMENT INVOLVED WITH MAT 06G – OVERHEAD SECONDARY SYSTEM WITH SERVICE DROP



New Business (NB)-related Capacity Work (MAT 06H) is for capacity reinforcement projects that allow the energization of new customer load associated with an application for service. Customers submit applications for service for new facilities and load increases at existing facilities. PG&E's Distribution Planning Engineers forecast the need for these projects, based on these applications for service (see Section B.1). Completion of these projects is important to customers who require service so that they can open their establishments, move into their homes, begin their manufacturing, or charge and operate their vehicles. Energization delays can result in loss of customer productivity, inconvenience, and possible loss of income. Delays can also make it challenging for customers and local governments to meet the state's building electrification and transportation electrification goals, and lack of funding for these activities especially challenges PG&E's ability to meet its energization timeline requirements established in D.24-09-020.

Operational Capacity Projects (MAT 06I) generally include two distinct types of distribution line work: (1) completing mainline loops or installing mainline back-ties; and (2) operational capacity projects to reduce the number of customers or the load on certain heavily loaded circuits. Additionally, there are some projects in MAT 06I that install switches or reconductor existing distribution line to increase local operational capacity, based on input from field personnel or engineers who operate the system.

Circuits without sufficient ties to other circuits, with 6,000 or more customers per circuit, or with a load of more than 600 amps, pose two issues: (1) a large number of customers are affected when an outage occurs due to a circuit breaker opening; and (2) typical loading limits on adjacent circuits could hinder the ability to reconfigure highly-loaded circuits. These issues negatively affect service reliability in both customer outage frequency and duration. Mainline tie projects typically allow for improved ability to reconfigure circuits in emergencies and for planned clearances. Projects in this category can reduce outage durations by increasing the ways that unserved load can be moved from de-energized circuits and circuit sections to energized ones.

b. Forecast

Table 9-6 shows recorded and forecast spend for the types of distribution line work described in the previous section. The table does not include emergent capacity work, 4 kV conversion work, or capacity bridging solution forecasts which are provided in Sections C.3, C.4, and C.5.

TABLE 9-6
DISTRIBUTION CAPACITY (MWC 06)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027	2028	2029	2030
1	06A	Circuit Projects Associated with Sub Work	$11,131	$35,919	$20,161	$24,314	$38,338	$30,681	$13,800	$22,273	$28,937	$24,388	$15,887
2	06B	Overloaded Line Transformers	859	1,526	4,359	1,383	9,863	11,321	11,729	18,256	18,852	19,474	20,118
3	06D	Circuit Reinforcement – Small	2,014	2,472	2,293	488	858	55	639	389	489	575	–
4	06E	Circuit Reinforcement – Large(a)	20,982	21,405	14,819	12,510	23,913	19,875	36,283	44,020	101,443	59,771	44,096
5	06G	Secondary Voltage Complaints	2,185	4,149	4,420	4,023	4,441	4,531	4,694	4,863	5,038	5,219	5,407
6	06H	New Business Capacity(b)	53,899	74,413	96,814	103,050	136,823	212,745	221,558	109,867	75,640	14,942	6,498
7	06I	Operational Capacity	4,511	5,973	3,658	1,976	2,322	1,206	3,126	11,966	12,604	11,142	11,867
8	06#	Line Voltage Regulator Revolving Stock	10,713	10,434	7,557	7,246	706	10,000	10,650	100	100	100	100
9	06M	Cornerstone Capacity Automation	–	–	(11)	–	–	–	–	–	–	–	–
10	06K	Capacitor and Capacitor Control	43	281	464	162	(7)	–	–	–	–	–	–
11	06P	Regulator and Regulator Control	930	475	506	109	–	–	–	–	–	–	–
12		Total	$107,267	$157,046	$155,039	$155,262	$217,258	$290,414	$302,479	$211,733	$243,103	$135,611	$103,973

		Risk Mitigation and Control Programs		
	MAT	Risk ID	Risk Program Name	CBR
13	06B	DOVHD-C009WLDFR-C009	Overloaded Transformers Replacement	0.3

(a) Does not include MAT 06E forecast for 4 kV Conversion Program (Section C.4).

(b) Includes only identified 06H projects. Does not include MAT 06H forecast for Emergent Capacity (Section C.3); or MAT 06H forecast for Capacity Bridging Solutions (Section C.5).

Forecasts for 06A, 06D, 06E, 06H, and 06I[43] are based on identified projects developed as part of the annual DPP described in Section B.1. These projects are individually listed in this chapter's workpapers.[44] Project costs for more mature projects come from actual designs and cost estimates. For newly-identified projects, standard unit costs[45] were used to establish the rough project costs shown in workpapers. Identified projects required to mitigate capacity deficiencies were reported in the 2024 DDOR reports.

The 2027 forecast increases compared to 2024 recorded are primarily driven by new projects required to mitigate forecasted overloads and to energize new customers.

Capacity Work funding forecast in MWC 06H for identified projects is larger in the near-term, and decreases in later years, because most customers requesting new service for single, large-demand locations historically submit applications 1-3 years prior to their anticipated in-service date. The longer-term forecast for line work associated with future New Business Applications can be found in the emergent work forecast, Section C.3.

Cost increases for Overloaded Line Transformers (MAT 06B)[46] in 2027-2030 are mostly due to inclusion of Transformer Purchases in the forecast and, to a lesser extent, to a small increase in the number of planned replacements each year. Transformer Purchases were previously forecasted within the New Business program (MWC 16) in prior GRCs. Starting in the 2027 GRC, PG&E forecasts Transformer Purchases at the program level.[47]

PG&E is projecting a year-over-year decrease after 2027 for the Distribution Line Capacity Program shown in Table 9-6 above. As such, the simple escalation described in Exhibit (PG&E-11) for the attrition years (2028-2030) is

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43 Historical costs for obsolete programs such as Power Factor Management (MAT 06K) and Enable Distributed Generation (06P) are included in Exhibit (PG&E-4) WP 9-17, WP Table 9-10, lines 13 and 14.

44 Exhibit (PG&E-4), WP 9-19, Workpaper Table 9-12.

45 Exhibit (PG&E-4), WP 9-72, Workpaper Table 9-18.

46 Exhibit (PG&E-4), WP 9-71, Workpaper Table 9-17.

47 Exhibit (PG&E-4), Ch. 10.

not appropriate. PG&E requests that each attrition year for this program be separately authorized in the GRC as presented in Table 9-6.[48]

3. Emergent New Business Capacity (Capital MAT 46H, 06H)

a. Overview

The Emergent New Business-related Capacity Work (MAT 46H and 06H, Emergent) forecast is different from the identified new business work under 46H and 06H. The primary driver of emergent capacity work is customer load growth and future applications for service that require specific capacity projects for energization. These capacity needs will be identified when a formal customer application for service is received, as well as annually through the DPP forecast. Absent emergent capacity funding, new projects identified in the next five planning cycles will remain unfunded. And new applications for service that require capacity work would risk remaining unenergized.

To illustrate the impact of load applications on emergent work, 6,170 new applications for service for loads less than 2 MW have been received with a combined load of 568 MW since the 2023-2024 forecast cycle and the 2024 DDOR report of “Known Load Data” (DDOR Appendix G.1). Some of these applications will require capacity projects to support customer energization and these new loads and projects will be reported in August 2025 as part of the 2025 DDOR. At this time, however, the specific distribution capacity projects associated with these new applications for service have not yet been identified through the annual DPP and are thus considered emergent capacity work.

The importance of emergent funding for capacity work is that it allows new projects to start as soon as they are identified without waiting for funding in a subsequent GRC. Such a wait would be contrary to energization timeline requirements set by D.24-09-020[49] and contrary to customer expectations and PG&E’s obligation to serve. Completion of these projects is important to customers who require service to open their restaurants and shops, move into their homes, charge their electric vehicles and fleets, or begin their manufacturing. Energization delays could result in loss of customer productivity,

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48 Attrition adjustment policies and mechanics, including discrete expense and capital programs, are addressed in Exhibit (PG&E 11), Ch. 1, 2 and 3.

49 D.24-09-020, p. 47, Table 5.

inconvenience, and possible loss of income. Delays can also make it challenging for customers and local governments to support or meet their obligations under the state's building and transportation electrification goals (see Chapter 10, Section B for further discussion of the electrification policies driving this demand).

b. Forecast

Table 9-7 provides the forecast for emergent line capacity and substation capacity.

TABLE 9-7
EMERGENT NEW BUSINESS CAPACITY (MAT 06H, 46H)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted					Forecast					
			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	06H	Emergent New Business Capacity – Line Work	–	–	–	–	–	–	$46,661	$47,593	$59,326	$150,063	$236,696
2	46H	Emergent New Business Capacity – Sub Work	–	–	–	–	–	–	23,983	30,000	71,613	191,057	212,897
3		Total	–	–	–	–	–	–	$70,644	$77,593	$130,938	$341,120	$449,593

PG&E's forecast for emergent new business work is based on observed emergent work since the 2023 GRC filing.[50] This observed emergent work is calculated as the difference between identified or project-specific work in the 2023 GRC for years 2023-2026 (submitted in June 2021) and the work that has since emerged for each year (actual work for 2023 and 2024; and updated identified work forecasts for 2025 and 2026). Table 9-8 below shows the observed emergent work for MWC 06 and MWC 46 since the 2023 GRC filing. This forecast methodology is reasonable because it uses updated actual and forecast data to show the volume of work that emerges and is incremental to the known work at the time of filing a GRC. As illustrated in Table 9-8, later years of the GRC period have increasing amounts of emergent work. This is because the later years have greater separation from the time of the GRC forecast creation when fewer outer year projects were identified.

Given PG&E is forecasting a significant increase of emergent work for the post Test-Year periods (2028-2030), the simple escalation methodology described in Exhibit (PG&E-11)[51] for the attrition years (2028-2030) is not appropriate for this program. PG&E requests that each attrition year for this program be separately authorized in the GRC as presented in Table 9-7.

50 Exhibit (PG&E-4), WP 9-55, Workpaper Table 9-14.

51 Attrition adjustment policies and mechanics, including discrete expense and capital programs, are addressed in Exhibit (PG&E 11), Chs. 1, 2, and 3.

TABLE 9-8
2023 GRC OBSERVED EMERGENT NEW BUSINESS CAPACITY NEEDS AND 2027 GRC EMERGENT WORK REQUEST (THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2023	2024	2025	2026	Total
1	Identified Work in 2023 GRC	$131,746	$150,103	$99,027	$91,416	$472,293
2	Updated Identified Work Since 2023 GRC	$222,544	$317,497	$479,213	$540,990	$1,560,245
3	Observed Emergent Work (line 2-line 1)	$90,799	$167,394	$380,186	$449,574	$1,087,952
		2027	2028	2029	2030	Total
4	2027 Emergent Work Forecast (Table 9-7)	$77,593	$130,938	$341,120	$449,593	$999,245

As shown in Table 9-8, PG&E's 2027 emergent work forecast is less in 2027-2029 and consistent with 2030, compared to the observed emergent work. This request aims to meet overall affordability targets for each year, while still securing adequate funding during the 2027 GRC cycle to meet the expected emergent work.

Additionally, to further inform and validate the magnitude of funding necessary to address emergent work, PG&E conducted a survey of EV fast charging developers and fleet charging customers about future requests for service (EV Survey) and incorporated data from Large Load Studies[52] to forecast future investment needs.[53]

PG&E obtained a non-comprehensive list of planned, but not-yet-submitted, applications for service from EV charging station providers, EV charging grant funding recipients, Transit Agencies subject to the California Air Resources Board's Advanced Clean Truck rules, as well as discussions with online retail and logistics companies intending to begin electrification of their vehicle fleets. The results of the EV survey represent targeted sites that are highly desirable to multiple EV developers. PG&E believes that the 379 customer-identified sites

52 The Large Load Study Process performs a formal load interconnection study for larger loads and provides a completed report to the customer for signature.

53 PG&E also proactively surveys customers, local agencies, and tribal governments through the Community Engagement Survey. This process is still in its infancy and PG&E does not have sufficient confidence in the initial results of the survey to add these loads to the distribution planning forecast. The survey is still being refined to get clearer, more targeted responses and actionable information.

have a high likelihood of developing associated applications for service, due to existing transit or fleet locations, secured grant funding, and company climate goals. Many of the identified locations are in proximity to the intersection of major travel corridors and may see additional growth beyond projections received, as other EV developers look to develop additional sites in their vicinity. The cumulative load results by PG&E geographic planning division from EV charging station plans for 379 customer sites as provided by this EV Survey are provided in Table 9-9 below.[54]

TABLE 9-9
EV SURVEY, CUMULATIVE ADDED LOAD BY DIVISION

		CUMULATIVE LOAD KW										
Division	Number of Customers	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Central Coast	21	9,252	21,762	35,702	58,949	59,289	59,855	59,855	59,855	59,855	59,855	59,855
De Anza	17	12,060	22,230	35,460	55,800	55,800	55,800	55,800	55,800	55,800	55,800	55,800
Diablo	24	8,545	15,759	31,085	47,119	47,943	49,247	49,351	49,455	49,559	49,663	49,767
East Bay	11	6,660	16,338	25,552	37,537	37,777	38,177	38,177	38,177	38,177	38,177	38,177
Fresno	20	22,751	44,741	70,231	104,984	105,324	105,890	105,890	105,890	105,890	105,890	105,890
Humboldt	11	2,080	8,476	11,262	16,884	18,478	17,568	19,785	17,652	20,194	20,236	20,278
Kern	19	21,253	55,453	75,613	110,475	110,475	110,475	110,475	110,475	110,475	110,475	110,475
Los Padres	18	5,400	14,275	26,451	41,624	42,100	42,803	43,024	43,245	43,466	43,687	43,908
Mission	29	22,415	59,556	112,594	146,449	146,789	147,355	147,355	147,355	147,355	147,355	147,355
North Bay	18	10,588	17,785	26,792	39,857	40,396	41,161	41,360	41,559	41,758	41,957	42,156
North Valley	15	1,260	8,696	13,812	21,768	22,424	23,400	23,576	23,752	23,928	24,104	24,280
Peninsula	12	13,052	26,178	43,318	67,875	67,975	68,141	68,141	68,141	68,141	68,141	68,141
Sacramento	26	9,270	24,033	46,200	66,982	67,475	68,194	68,347	68,500	68,653	68,806	68,959
San Francisco	3	3,960	7,200	11,160	17,190	17,190	17,190	17,190	17,190	17,190	17,190	17,190
San Jose	54	13,860	29,582	45,512	71,355	71,355	71,355	71,355	71,355	71,355	71,355	71,355
Sierra	18	5,490	16,350	25,200	40,499	40,969	41,665	41,795	41,925	42,055	42,185	42,315
Sonoma	25	4,320	7,710	12,070	19,298	19,538	31,625	31,625	31,625	31,625	31,625	31,625
Stockton	22	10,200	20,460	59,165	72,363	72,742	73,347	73,386	73,425	73,464	73,503	73,542
Yosemite	16	10,350	22,447	35,184	53,730	53,777	53,950	53,957	53,964	53,971	53,978	53,985
TOTAL	379	192,766	439,031	742,363	1,090,738	1,097,816	1,117,198	1,120,444	1,119,340	1,122,911	1,123,982	1,125,053

54 This data is also available at the substation-level for each of the 379 customer sites in Exhibit (PG&E-4), WP 9-66, Workpaper Table 9-16.

These loads were added to the 2022 IEPR forecast to obtain a set of projects that represent a possible scenario for emergent work. This growth does not represent a double counting of the IEPR EV fast charging forecast due to the nature of light duty EV forecast in the IEPR. System-level IEPR light duty EV forecasts are dominated by nighttime home charging and do not adequately represent local impacts of fast charging and fleet charging loads for the following reasons: (1) the peak of light duty EV growth in the IEPR is midnight while actual EV fast charging sites peak during daylight driving hours on travel weekends, (2) the IEPR profile has a lower ratio of maximum load to average load than observed at actual EV fast charging sites,[55] and (3) EVs, unlike homes, schools, or stores, move on a daily basis, potentially impacting multiple locations of the grid, a duplication that is lost when loads are summed to the system-level (i.e.: the same vehicle is likely to charge at various locations and different distribution circuits throughout its use but this all occurs on the same PG&E system).

The loads provided in the EV Survey were added to the existing 2023-2024 substation transformer and distribution circuit forecasts.[56] These forecasts use the 2022 IEPR to assess where substation bank and circuit overloads would occur.[57] The inclusion of the EV Survey loads resulted in 62 potential substation and new circuit capacity projects.[58] The inclusion of large load study data resulted in the

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55 As an example of the impact of this lower demand assumption, a study of a 32-charger interconnection in Mountain View, California showed that the IEPR equivalent demand from 138 chargers was required to cover the new load.

56 Substation-level details for the sites from the EV Survey can be found in Exhibit (PG&E-4), Ch. 9, WP 9-66, Table 9-16. Data at a more granular level is not provided so that customer confidentiality is preserved.

57 See Exhibit (PG&E-4), Ch. 9, WP 9-78, Project Summary – New Business Related Capacity – Emergent Work for the process map for estimating capacity projects using EV Survey results.

58 Exhibit (PG&E-4), WP 9-57, Workpaper Table 9-15.

identification of 8 additional projects. PG&E then used standard unit cost information to calculate an emergent forecast.[59]

In Figure 9-5, the 62 potential substation locations are superimposed on the Electric Power Research Institute (EPRI) eRoadMap data of light-, medium- and heavy-duty transportation electrification energy needs across PG&E's service area in 2030.[60] In developing eRoadMap, EPRI gathered data from travel models, vehicle manufacturers, vehicle registrations, and other sources to document local daily miles traveled and the primary locations where vehicles are stationed.[61] This data is then translated to daily energy and power needs for the period of 2024-2030. This dataset illustrates demand signals around the timing and pace of EV adoption and provides a view of corresponding electrification needs across the US, inclusive of PG&E's service territory. As can be seen in Figure 9-5, there is notable alignment between the results of the EV Survey and where eRoadMap shows there to be significant anticipated energy demand. This is true even with the lack of local data, such as transit agency needs, which PG&E's EV Survey includes, but eRoadMap does not.[62] This corroborates and further validates the analysis and forecasts presented.

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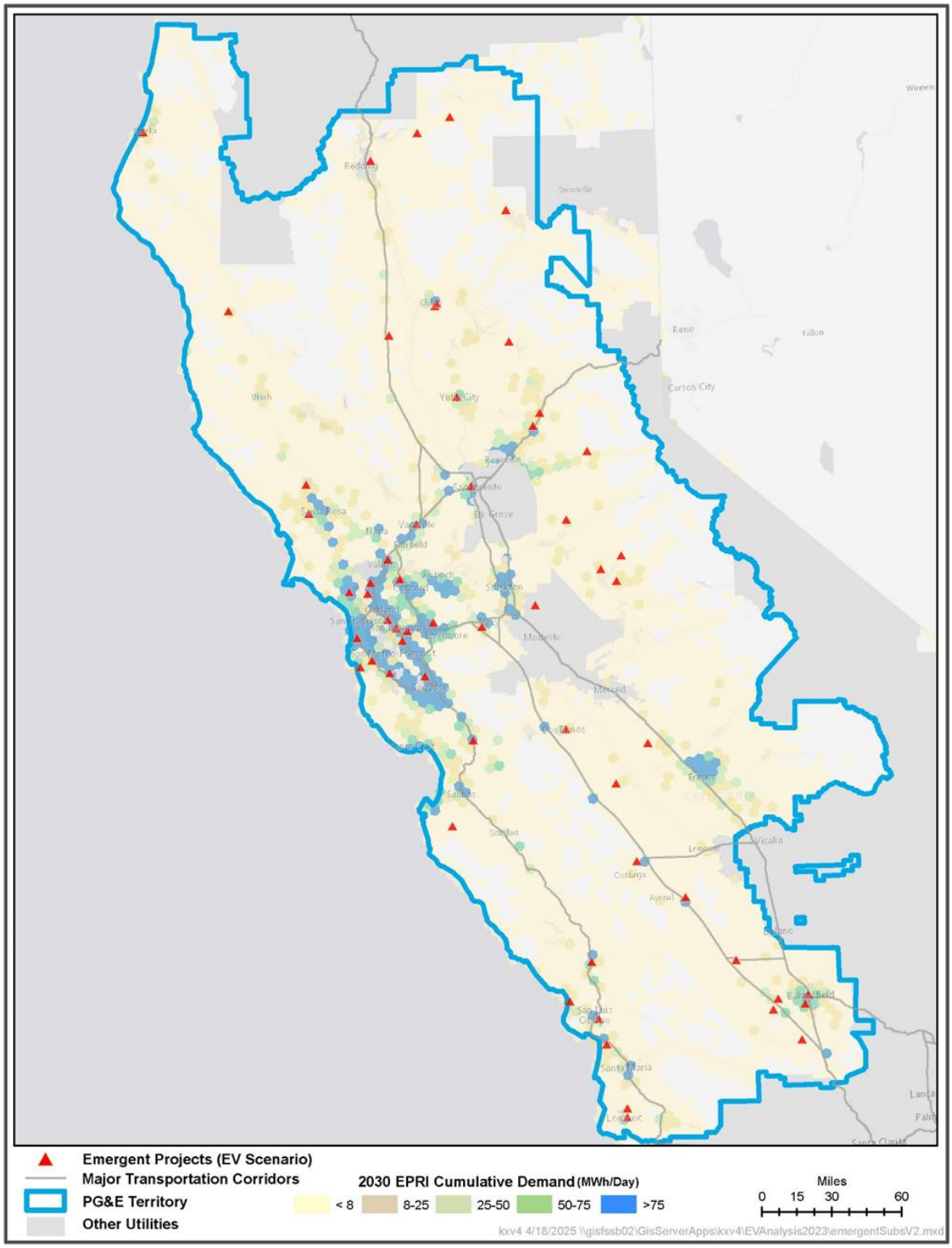
59 While PG&E uses the EV Survey to understand investment needs for emergent substation work related to EVs, these 62 potential substation projects are not listed among the identified projects in WP Table 9-12. The potential substation projects, listed in WP Table 9-15, are not actionable at this time for the following reasons: (1) no formal application for service has been provided, (2) the process for using pending loads such as those obtained by means of the EV Survey is still being formalized, and (3) an actual engineering analysis was not performed on these overloads which would provide and review multiple options to determine the most cost effective mitigation.

60 EPRI eRoadMAP, available at: <https//eroadmap.epri.com> (accessed April 24, 2025).

61 EPRI eRoadMAP fact sheet, available at: <https://eroadmap.epri.com/docs/eRoadMAP_fact_sheet.pdf> (accessed April 24, 2025).

62 eRoadMap does not include specific local information around the electrification needs of the California Transit Agencies subject to the Advanced Clean Trucks rule, which PG&E's EV Survey does include.

FIGURE 9-5
POTENTIAL CAPACITY PROJECTS FROM EV SURVEY SUPERIMPOSED ON EPRI eRoadmap DATA OF TRANSPORTATION ELECTRICITY CONSUMPTION IN 2030



Since the 62 EV Survey projects above do not take into account any line-section capacity investments, PG&E estimated stand-alone line

section capacity (MWC 06H) investment needed based on the following two assumptions: (1) 50 percent of the total annual new business line work expenditures (06H) are associated with substation work (46H), and 50 percent are stand-alone distribution line section upgrades;[63] and (2) projects that install substation transformers without the need for new circuits will require line work in order to move load between existing and new transformers to achieve full transformer utilization across all transformers in a substation.

Table 9-10 shows the results of PG&E's analysis of investment needs to meet the EV load survey and large load studies. The analysis shows that PG&E's observed emergent work forecast methodology (Table 9-8) is consistent with the magnitude of forward-looking data on total investment needs. Note that this analysis only includes projects driven by the EV Survey and in-flight Large Load Studies. The actual work that emerges over the period of the 2027 GRC could be significantly higher due to other types of customer loads.

TABLE 9-10
EV SURVEY AND LARGE LOAD STUDY EMERGENT NEW BUSINESS CAPACITY NEEDS
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	2027	2028	2029	2030	Total
1	Projects from EV Survey[(a)]	$131,785	$259,603	$479,650	$203,018	$1,074,055
2	Large Load Study Projects[(b)]	30,946	36,070	17,034	22,257	106,307
3	Total Emergent Work (line 1+line 2)	$162,731	$295,673	$496,684	$225,274	$1,180,362

(a) Exhibit (PG&E-4), WP 9-70, Workpaper Table 9-15, line 65.
(b) Exhibit (PG&E-4), WP 9-73, Workpaper Table 9-15, line 74.

4. 4 KV Voltage Conversion Program (Capital MAT 46A, 06E)

a. Overview

Most of PG&E's distribution system is operated at 12,000 or 20,800 volts. However, PG&E's distribution system also includes 4,160 volt, or 4 kV distribution systems, which operate at a lower

[63] In 2024, the historical split was 49 percent for stand-alone line upgrades.

nominal voltage. These systems have been a part of PG&E's distribution network from at least the 1930s. These systems can be found across the PG&E territory, especially in California's oldest downtown areas, such as San Francisco, Oakland, Berkeley, San Jose, Stockton, Santa Cruz, and Monterey. As can be seen in Figure 9-6, two areas with large, interconnected groups of 4 kV circuits are the East Bay, from Richmond to Hayward and the San Francisco Peninsula, from San Francisco to Palo Alto. Figure 9-7 shows the locations of non-Bay Area 4 kV systems which are located in San Jose, Santa Cruz, Capitola, Scotts Valley, Watsonville, Carmel, Pacific Grove, and Monterey. In total, over 350,000 customers are served at 4 kV.

FIGURE 9-6
4 KV SYSTEMS OF THE GREATER BAY AREA

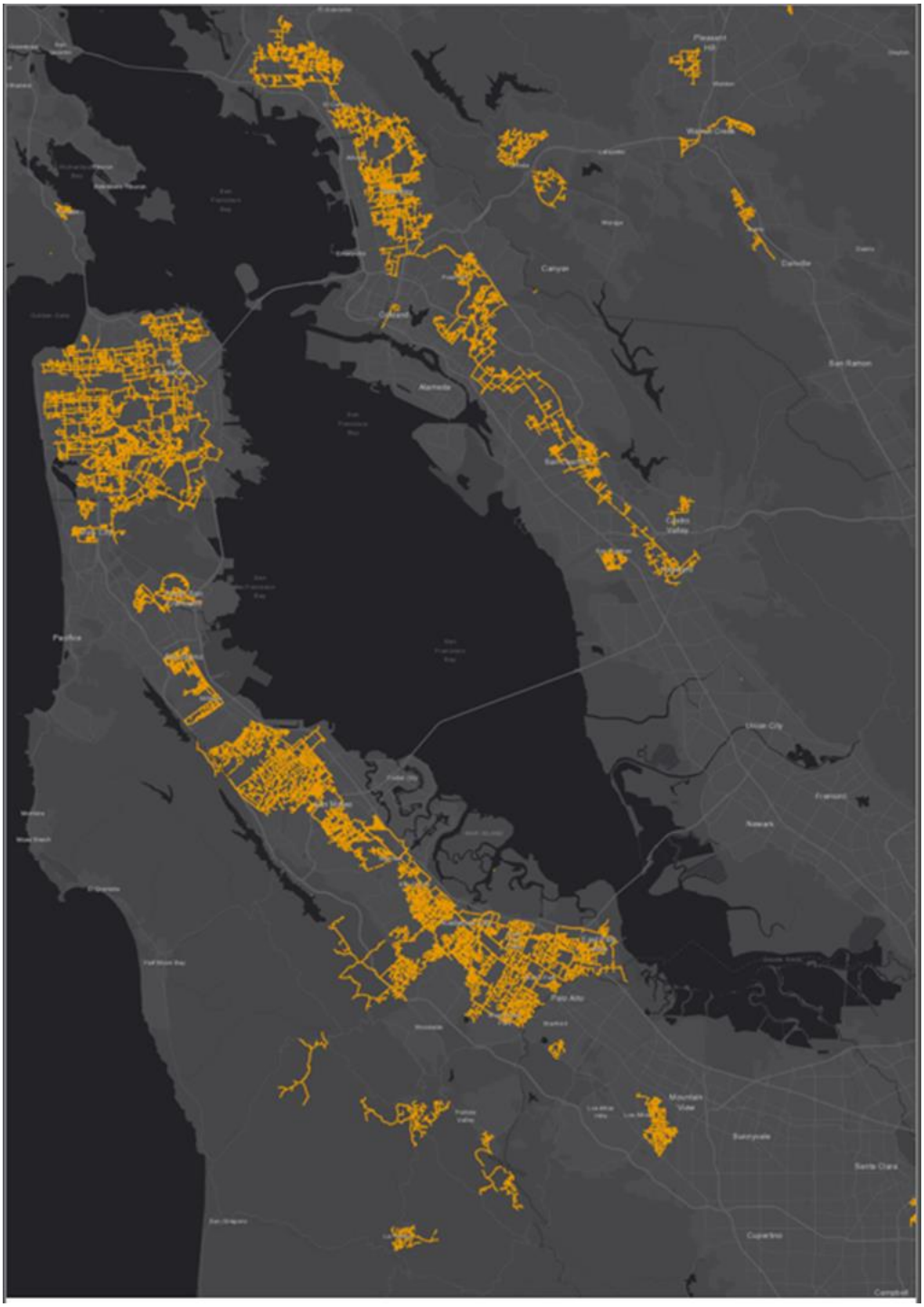
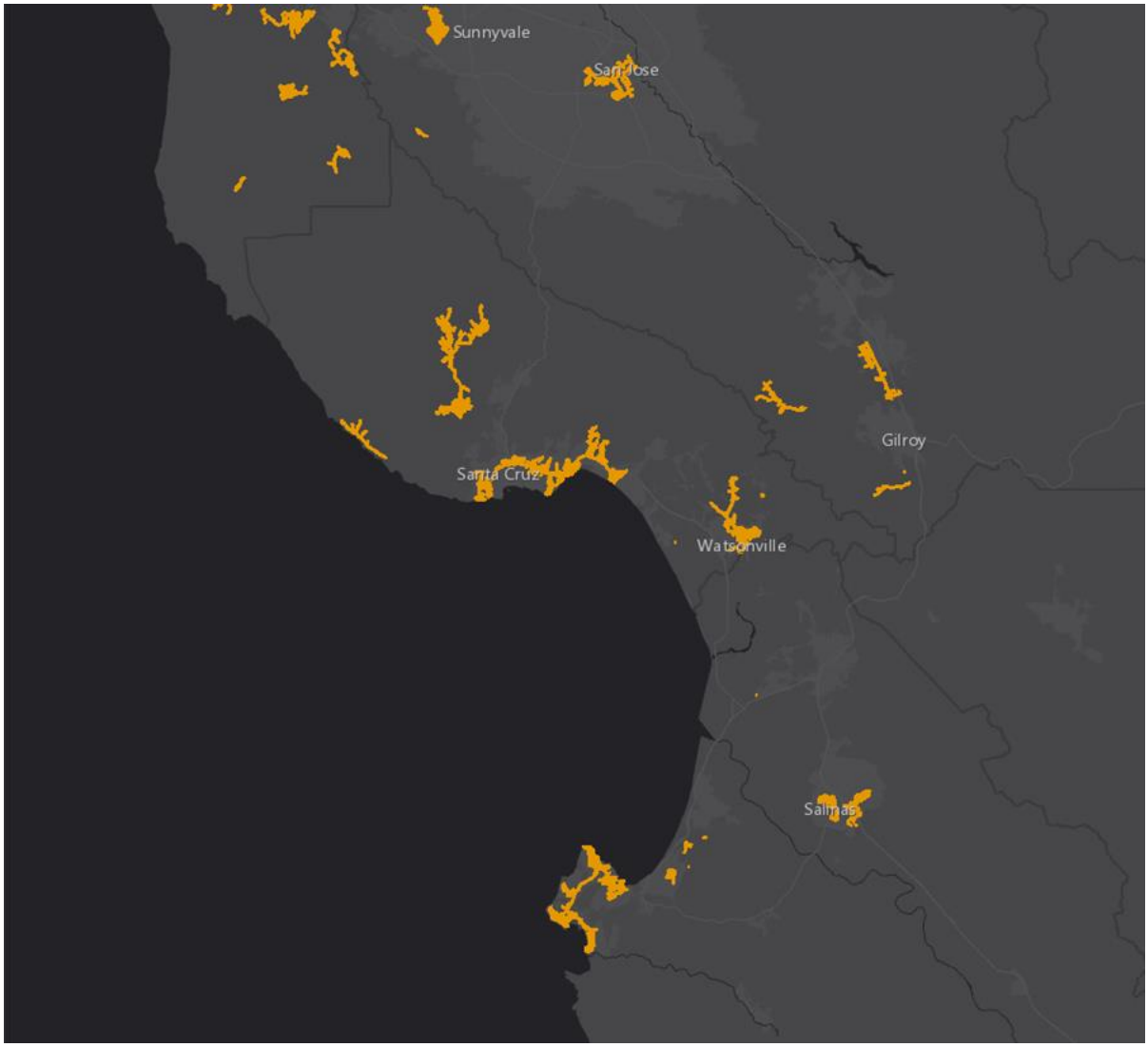


FIGURE 9-7
4 KV SYSTEMS OF SAN JOSE AND THE MONTEREY BAY AREA



Over time, 4 kV systems were superseded by more efficient voltages. As can be seen from Table 9-11, circuits with higher operating voltages are capable of serving more load and more customers than circuits with lower operating voltages.

TABLE 9-11
IMPACT OF NEW LOAD AT DIFFERENT SYSTEM OPERATING VOLTAGES

Line No.	Nominal Operating Voltage (Volts)	Colloquial Name for System	Assumed Maximum Circuit Capacity (Amps) of a Theoretical Circuit[a]	Maximum Circuit Capacity (kW)[b]	Maximum # of customers (@ 5 kW per customer)[c]	% of circuit capacity represented by 500 new heat pumps @ 5 kW each[d]
1	4,160	4 kV	570	4,107	821	61%
2	12,000	12 kV	570	11,847	2,369	21%
3	20,780	21 kV	570	20,515	4,103	12%

(a) Assumes a theoretical limiting factor of a 600 amp air switch de-rated by 5 percent for phase unbalance.

(b) Kilowatts (kW) equals amps times volts times square root of three divided by 1,000.

(c) Equals maximum circuit capacity in kW divided by 5 kW per customer.

(d) Equals 5 kW times 500 divided by maximum circuit capacity in kW.

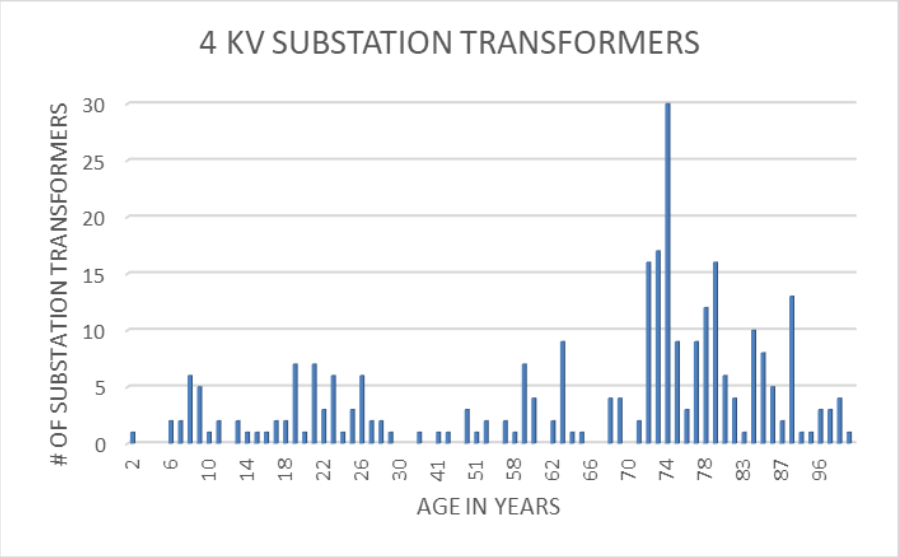
For decades, growth on 4 kV systems has been minimal due to three factors: a lack of new construction in older commercial and residential areas, little new air conditioning load, and PG&E's practice of serving any new load in 4 kV areas from adjacent 12 and 21 kV circuits whenever practicable. This means that the 4 kV system has not been expanded, but neither has any significant investment been made to convert these assets to a higher voltage.

Today the 4 kV system faces a series of unprecedented challenges. As commercial and residential customers transition to EVs and all-electric buildings, the 4 kV system will be unable to meet these growing needs. Without voltage conversion to higher voltages, existing 4 kV areas will remain islands where customer growth and expansion are limited and where each customer application for service requires extension of nearby, higher-voltage circuits, one customer at a time. Because of this, areas served by 4 kV circuits will find it challenging to meet the state's building electrification and transportation electrification goals. Customers will also be challenged when they seek to add behind-the-meter generation in these areas, because generation, like load, faces the same 4 kV circuit capacity limits as seen in Table 9-11 above.

In addition, many 4 kV substation assets are nearing or exceeding their useful lifespan of 40 years.[64] Figure 9-8 below shows the count, by age, of 4 kV substation transformers on the system. Note that other 4 kV substation elements, such as circuit breakers and switchgear, are also aging at the same rate. Maintenance has become difficult on these assets as replacement parts are no longer available and when failure occurs it leads to the replacement of all substation assets with whatever is readily available and whatever can be quickly installed. Because of the need to restore power quickly and because voltage conversion projects require detailed planning and design, it is rare that voltage conversion of the failed system is an option.

In summary, a planned program of 4 kV voltage conversion is needed to upgrade the grid to meet state decarbonization goals, meet customer demands, and to replace obsolete 4 kV equipment with more efficient voltages.

FIGURE 9-8
AGE OF 4 KV SUBSTATION TRANSFORMERS



64 "Although actual service life varies widely depending on the manufacturer's design, quality of assembly, materials used, operating history, current operating conditions, and maintenance history, the average expected life for an individual transformer is statistically about 40 years." U.S. Department of the Interior, *Transformers: Basics, Maintenance, and Diagnostics* (April 2005), p. 217.

FIGURE 9-9
THREE 4 KV TRANSFORMERS AT RIDGE SUBSTATION, BERKELEY, INSTALLED IN 1937



b. Forecast

Table 9-12 provides the forecast for the 4 kV conversion program.

TABLE 9-12
4 KV VOLTAGE CONVERSION PROGRAM (MAT 06E, 46A)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted					Forecast					
			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	06E	4 kV Voltage Conversion – Line Work	–	–	–	–	–	–	–	$23,750	$144,006	$144,005	$144,012
2	46A	4 kV Voltage Conversion – Sub Work	–	–	–	–	–	–	–	5,250	26,420	26,420	26,420
3		Total	–	–	–	–	–	–	–	$29,000	$170,427	$170,426	$170,433

PG&E's forecast is based on a 15 to 20-year timeframe for conversion of all 4 kV substation transformers and circuits. The projects that make up the 4 kV voltage conversion forecast are listed in this chapter's workpapers.[65] Standard unit costs[66] were used to establish the rough project costs. Some project costs were derived from 4 kV substation asset emergency projects that performed voltage conversions. Prioritization methodology[67] was based on forecasted loading, asset health, voltage violations, and outage history. 4 kV projects lower in prioritization may rise due to changes in asset health or changes in loading. Since this program is new, there are no recorded historical amounts from prior years.

The 4 kV conversion program is expected to grow from $29 million in 2027 to $170 million in 2028[68] due to the multi-year project lifecycle. Estimating and design typically occur in the first year of the project and results in lower expenditures than the construction and material purchases that occur in the second and later years of the project. As more mature projects move into construction, newer projects begin their lifecycle in estimating and design. To sufficiently fund the 4 kV projects in 2028-2030 (the attrition years), PG&E requests separate authorization for each attrition year for this program as presented in Table 9-12, which deviates from the simple escalation approach described in Exhibit (PG&E-11). See Exhibit (PG&E-11), Chapters 1, 2, and 3 for more discussion.

5. Capacity Bridging Solutions (Capital MWC 06H)

a. Overview

Capacity Bridging Solutions (MAT 06H) is a new program which aims to accelerate customer energization in light of state law and policy. In the Powering Up Californians Act, the state legislature calls for

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65 Exhibit (PG&E-4), WP 9-49, Workpaper Table 9-13.

66 Exhibit (PG&E-4), WP 9-72, Workpaper Table 9-18.

67 Exhibit (PG&E-4), WP 9-82, Project Summary – 4 kV Conversion Program

68 Exhibit (PG&E-4), WP 9-17, Workpaper Table 9-10, line 5 and WP 9-18, Workpaper Table 9-11, line 1.

prompt energization of customers to help support housing development, businesses, and meet decarbonization goals. In Decision 24-09-020, the Commission adopted average and maximum energization timelines to accelerate energization as part of California's path towards decarbonization. PG&E plans to use solutions such as re-deployable battery energy storage systems (BESS) to partially or fully energize customers on an interim basis while a permanent capacity solution is designed and built. This would allow customers to receive service sooner than the in-service date of a permanent solution while preventing overloads on existing infrastructure due to the new load.

PG&E's current standard bridging solutions (as described in Section B.1.e) include load limit letters and flexible service connections. These options do not meet the needs of customers with inflexible loads, or customers located in constrained areas with multiple new service applications or circuits where capacity constraints are due to voltage issues rather than thermal constraints. If a capacity-constrained circuit can accommodate BESS charging and discharging without introducing new constraints or unresolvable violations, and if the BESS capacity can in turn accommodate partial or full energization of customers awaiting a distribution capacity project, then PG&E can evaluate BESS as a bridging solution against, or in tandem with, other bridging solutions to meet customer needs while addressing system constraints. For circuits where BESS is a fit, PG&E will prioritize the BESS solution similar to existing distribution capacity projects. For such projects, prioritization is based on the technical feasibility, customer requested in-service date, whether the project serves emergency or critical services in the community, and any commitments made to these communities, elected officials, or the CPUC. To increase the value that the bridging solution delivers, PG&E may also prioritize circuits based on the lead time for the permanent distribution capacity project relative to the lead time for a BESS as a bridging solution. Once the permanent capacity project is completed, if the BESS functionality is no longer valuable on the original circuit then PG&E will re-deploy the BESS on a different circuit for the same bridging purpose.

b. Forecast

Table 9-13 provides the forecast for the capacity bridging solution program.

TABLE 9-13
CAPACITY BRIDGING SOLUTIONS (PORTION OF MAT 06H)
SUMMARY OF CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted					Forecast					
			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1	06H	Capacity Bridging Solutions	–	–	–	–	–	–	–	$6,000	$6,000	$12,000	$12,000

Capacity bridging solutions is a new program with no recorded costs. PG&E's forecast is based on a limited deployment of BESS as a bridging solution: one deployment in 2027, one deployment in 2028, two deployments and one re-deployment in 2029, and two deployments and one re-deployment in 2030. The capacity bridging project costs are based on actual BESS hardware costs in 2022 from a separate PG&E initiative for BESS assets enabled for re-deployment, with further assumptions about average project size and ratio of BESS hardware costs to other project costs.[69]

Given that PG&E is forecasting to double the BESS deployment in 2029 from 2028, the simple escalation methodology described in Exhibit (PG&E-11)[70] for the attrition years (2028-2030) is not appropriate for this program. PG&E requests that each attrition year for this program be separately authorized in the GRC as presented in Table 9-13 above.

69 Please see the Capacity Bridging Solutions project summary provided in Workpapers to this chapter for additional details. Exhibit (PG&E-4), Ch. 9, WP 9-85, Project Summary – Capacity Bridging Solutions.

70 Attrition adjustment policies and mechanics, including discrete expense and capital programs, are addressed in Exhibit (PG&E 11), Ch. 1, 2 and 3.

6. Electric Engineering and Planning Program (Expense MWC FZ)

a. Overview

All the expense work discussed in this chapter relates to the Engineering and Planning program and is tracked in five MATs within MWC FZ.[71]

General engineering work (MAT FZA) is labor required to support many types of work such as PG&E's annual Distribution Planning Process, New Business (NB), Work at the Request of Others (WRO), reliability, overhead asset management, underground asset management, grid modernization, generation interconnections, and community rebuild. This engineering labor also develops electronic control settings for protective and voltage support equipment, as well as responds to customer inquiries regarding electromagnetic field (EMF) and reliability concerns.

General Engineering work (MAT FZA) is a foundational mitigation to the Failure of Distribution Overhead Asset Risk (DOVHD). Foundational activities are initiatives that support or enable mitigation or control programs but do not directly reduce the consequences or reduce the likelihood of safety risk events. For example: the annual system planning protection review and engineering work forecast herein does not directly reduce risk; instead the risk is reduced when the reviews indicate a need for control work to be done in the following RAMP control activities identified in Exhibit (PG&E-)4, Chapter 15: Distribution Maintenance Replacements (MATs KAA, 2AA, and KAQ), Emergency Distribution Replacements (MAT 17B), and pole replacements (MATs 07D and 07L).

Voltage complaint investigation work (MAT FZB) involves investigating secondary voltage complaints that a Troubleshooter cannot resolve on the first visit. This involves setting recording voltage meters at customer sites to measure voltage, investigating the results,

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71 FZ work associated with Enhanced Powerline Safety Settings (EPSS) is found in Exhibit (PG&E-4), Ch. 6 "Wildfire Operational Mitigations". FZ work associated with the Asset Health and Performance Center can be found in Ch. 5 "Wildfire Situational Awareness and Forecasting."

developing a cost-effective solution to the issue, and communicating results and actions to the customer. Timely resolution of customer voltage complaints is critical to the productivity and satisfaction of PG&E customers. Proper voltage is essential to the operation of customer equipment. Motors will experience burnout if voltages are beyond design tolerances and many motor controllers will not allow motors to function unless voltage is within these tolerances. Solar-electric generating systems will not generate power if voltages are above certain thresholds and customers may suffer financial hardships as a result.

Transformer report management work (MAT FZC) involves investigating potentially overloaded distribution line transformers. Investigating overloaded transformers prior to failure is important because overloaded transformers have a higher risk of failure than normally-loaded transformers due to heating of internal transformer components. Transformer failures can result in lengthy outages for customers, decreasing customer productivity, preventing customers from charging electric vehicles, causing inconvenience and possible loss of income.

Field work plans (MAT FZD) involve supporting operational field work initiated by engineering personnel, such as phase balancing, and replacing fuses that are projected to be overloaded. This critical field work is necessary to make changes to the system to prevent overloads and voltage imbalance. For example, balancing load across the three-phase system can prevent one phase from becoming overloaded which avoids equipment damage and/or outages when protective devices detect the overload and de-energize the circuit. Increasing the size of tap line fuses can help avoid customer outages if fuses are undersized for present loading.

Distribution Line Tech and Troubleshooter field work (MAT FZE) includes implementing load transfers, control device setting changes/downloads, and other specific field investigations. This critical field work is necessary to reconfigure the system to prevent overloads optimize reliability, provide adequate protection, and avoid equipment

damage and/or customer outages when mainline protective equipment detects the overload and de-energizes primary distribution lines.

b. Forecast

Table 9-14 provides the expense forecast for the engineering and planning program.

TABLE 9-14
ELECTRIC ENGINEERING AND PLANNING PROGRAM (MAT FZA, FZB, FZC, FZD, FZE)
SUMMARY OF EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	MAT	Description	Recorded Adjusted 2020	2021	2022	2023	2024	Forecast 2025	2026	2027
1	FZA	General Engineering	$11,877	$11,240	$9,138	$12,145	$13,552	$12,086	$15,715	$16,145
2	FZB	Voltage complaint Investigation	1,127	1,611	1,490	1,762	1,652	1,549	1,381	1,231
3	FZC	Transformer Report Management	28	37	2	–	–	44	40	35
4	FZD	Field Work Plans	468	331	385	283	573	316	282	251
5	FZE	Distribution Line Tech and Troubleshooter	1,658	2,270	2,309	2,543	2,328	2,526	2,252	2,008
6		Total	$15,158	$15,488	$13,324	$16,733	$18,105	$16,522	$19,670	$19,670

Foundational Activities, Risk Controls and Risk Mitigation Programs

	MAT	Risk Program ID	Risk Program Name	CBR
7	FZA	DOVHD-C008	Annual Protection Reviews	Foundational

The General Engineering (FZA) forecast assumes increasing costs in 2026 and 2027 to account for increasing complexity of distribution planning tools with a commensurate increase in distribution engineer time spent learning and using the planning tools, time spent implementing changes to planning processes, and increasing complexity and time spent on generation interconnection studies. This includes scenario planning analyses, pending load survey implementation, and an increase in phase balancing studies to better utilize existing systems. The remaining program forecasts were developed using recorded historical averages for each MAT code (FZB, FZC, FZD, and FZE) and assuming decreasing costs each year due to a decrease in the number of requests for work.

D. Compliance

1. Deferred Work Analysis

The 2023 GRC Decision (OP 4) requires PG&E to continue following the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC.[72] The Deferred Work Settlement requires PG&E to include testimony on deferred work if the following criteria are met:

a) The work was requested and authorized based on representations that it was needed to provide safe and reliable service;

b) PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and

c) PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.

For work covered in this Chapter, PG&E applied these criteria as explained in Analysis of "Deferred Work" discussion set forth in the Electric Distribution Forecast Summary and Investment Planning chapter.[73] This analysis is presented in the workpapers supporting that chapter.[74]

Based on this analysis, no work included in this Chapter was identified as "deferred work" under the terms of the Deferred Work Settlement.

2. Decision 24-07-008 Reporting Requirements

The decision authorizing PG&E's request for a ratemaking mechanism pursuant to Pub. Util. Code Section 937 (D.24-07-008) requires PG&E to report in its general rate case: (a) Any spending recorded to the energization cost mechanism authorized in a granular enough manner to allow for the review of Maintenance Activity Types and specific line items within Major Work Categories 06, 10, 16, and 46; and (b) The project level accounting of equipment capacities before and after construction, estimated and actual costs, allowances under Rules 15 and 16, customer payments

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72 Pursuant to D.23-11-069, p. 900, OP 4, "Pacific Gas and Electric Company shall continue to follow the directives in the Deferred Work Settlement and submit the related data in its 2027 GRC, subject to the limitations of Public Utilities Code Section 8386.3, which restricts the diversion of revenues authorized for certain wildfire mitigation activities."

73 Exhibit (PG&E-4), Ch. 2, Section E.1.b.

74 Exhibit (PG&E-4), WP 2-19.

made in support of construction, and other relevant data served concurrently with each December annual electric true-up advice letter.[75] This report for MWCs 06 and 46 is provided in workpapers.[76]

E. Accounts

1. Energization Capacity New Business Interim Memorandum Account (ECNBIMA)

In D.24-07-008, the Commission authorized the Energization Capacity New Business Interim Memorandum Account (ECNBIMA) for interim cost recovery of energization costs, including MWC 06 and 46, pursuant to Public Utilities Code (PUC) Section 937. Only capital expenditures incurred for eligible energization projects placed in service after January 1, 2024, and by January 1, 2027, are eligible for recovery through the ECNBIMA.

PG&E proposes to conduct the reasonableness review of ECNBIMA in a subsequent track of this proceeding in 2027 when all entries into the account are complete. Upon completion of the reasonableness review of costs recorded to the account associated with capital additions through December 31, 2026, and incorporation of the ongoing revenue requirements beyond 2026 into a future GRC, PG&E plans to close the account. PG&E summarizes its request to retain, modify, or discontinue existing cost recovery mechanisms as described in this exhibit and associated revenue requirements in Exhibit (PG&E10), “Results of Operations,” Chapter 16 “Balancing Accounts.”

F. Conclusion

Based on the demonstration above and on the evidence presented in the associated attachments and workpapers to this chapter, PG&E respectfully requests that the Commission:

1) Adopt the expense forecasts in Section A.2, Table 9-1; and
2) Adopt the capital forecasts in Section A.2, Table 9-2.

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75 D.24-07-008, pp. 95-96, Ordering Paragraph 24 and 25 also requires PG&E to report on its Distributed Energy Resources Management System (DERMS), flexible service connection pilot, and demand and dynamic flexibility rates. This is provided in Exhibit (PG&E-4), Ch. 22.

76 Exhibit (PG&E-4), Ch. 9, WP 9-96 and WP 9-104, Workpaper Tables 9-27 and 9-28.

3) Adopt the specific post Test-Year attrition proposed for the Capacity Program capital forecasts as described in Section C.1, C.2, C.3, C.4, and C.5.