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Date: November 25, 2021  
Witness(es): Various

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**PACIFIC GAS AND ELECTRIC COMPANY**

**2023 GENERAL RATE CASE**

**EXHIBIT (PG&E-4)**

**ELECTRIC DISTRIBUTION**

**CHAPTERS 16-APPENDIX B**

**[INCLUDES ERRATA THROUGH FEBRUARY 25, 2022 AND  
FEBRUARY 25, 2022 SUPPLEMENTAL TESTIMONY]**

**VOLUME 3 OF 3**

**(PUBLIC VERSION)**

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2023 GENERAL RATE CASE  
EXHIBIT (PG&E-4)  
ELECTRIC DISTRIBUTION

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<sup>1</sup> New witness from the June 30, 2021 submission.

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**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 16**  
**DISTRIBUTION SYSTEM AUTOMATION AND PROTECTION**  
**[INCLUDES NOVEMBER 5, 2021 ERRATA]**

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1                                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                                   **CHAPTER 16**  
3                                   **DISTRIBUTION SYSTEM AUTOMATION AND PROTECTION**

4   **A. Introduction**

5       **1. Scope and Purpose**

6                   The purpose of this chapter is to demonstrate that Pacific Gas and  
7                   Electric Company's (PG&E or the Company) expense and capital  
8                   expenditure forecasts for its Electric Distribution (ED) System Automation  
9                   and Protection (DSAP or ED SAP) Program activities are reasonable and  
10                  should be adopted by the California Public Utilities Commission  
11                  (Commission).

12       **2. Summary of Request**

13                  PG&E requests that the Commission adopt its 2023 expense forecast  
14                  for the DSAP Program of \$3.0 million which is \$0.7 million more than  
15                  recorded 2020 expenses of \$2.3 million.<sup>1</sup>

16                  PG&E further requests that the Commission adopt its capital  
17                  expenditure forecasts for the DSAP Program of \$25.5 million for 2021,  
18                  \$26.4 million for 2022, \$27.0 million for 2023, \$27.8 million for 2024,  
19                  \$28.5 million for 2025, and \$29.3 million for 2026.<sup>2</sup> The 2023 capital  
20                  forecast is \$10.4 million, or 28 percent, lower than the 2020 recorded costs  
21                  of \$37.4 million.<sup>3</sup>

22                  Forecasts in this chapter are shown with escalation at the Major Work  
23                  Category (MWC) level and included in all expense and capital totals. For  
24                  more information on escalation, please refer to Chapter 2 of this exhibit.

25       **3. Overview of Recorded and Forecast Costs**

26                  PG&E records and forecasts capital and expense DSAP Program  
27                  activities in the MWCs shown in Table 16-1.

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1   Exhibit (PG&E-4), WP 16-5, line 5.

2   Exhibit (PG&E-4), WP 16-6, line 2.

3   Exhibit (PG&E-4), WP 16-6, line 2.

**TABLE 16-1**  
**DSAP**  
**MAJOR WORK CATEGORIES**

Line No.	MWCs	Description
1	Expense MWC	
2	HX	DSAP Support
3	Capital MWC	
4	09	ED SAP

1 Work in MWC 09 is further broken down into Maintenance Activity Type  
2 (MAT) codes, as described in Section C.2. MWC HX does not use MAT  
3 codes, but uses planning orders to further itemize expenditures as described  
4 in Section C.1.<sup>4</sup>

5 **a. Expense**

6 Figure 16-1 shows the walk from 2020 recorded expenses in  
7 MWC HX to the 2023 expense forecast. The forecast expenses will  
8 provide engineering support for automation and protection equipment.  
9 The 2023 forecast of \$3.0 million for MWC HX is \$0.7 million higher than  
10 the 2020 recorded expenses of \$2.3 million.<sup>5</sup> The variance reflects an  
11 increase to review protective relay settings for distribution feeder circuits  
12 in support of Public Safety Power Shutoff (PSPS), outage reviews,  
13 standards development, Rule 21 compliance, Distributed Generation  
14 (DG) support, mobile generators and islanding initiative. Supervisory  
15 Control and Data Acquisition (SCADA) software license fees previously  
16 recorded in MWC HX will be recorded in MWC HG beginning in 2021.<sup>6</sup>

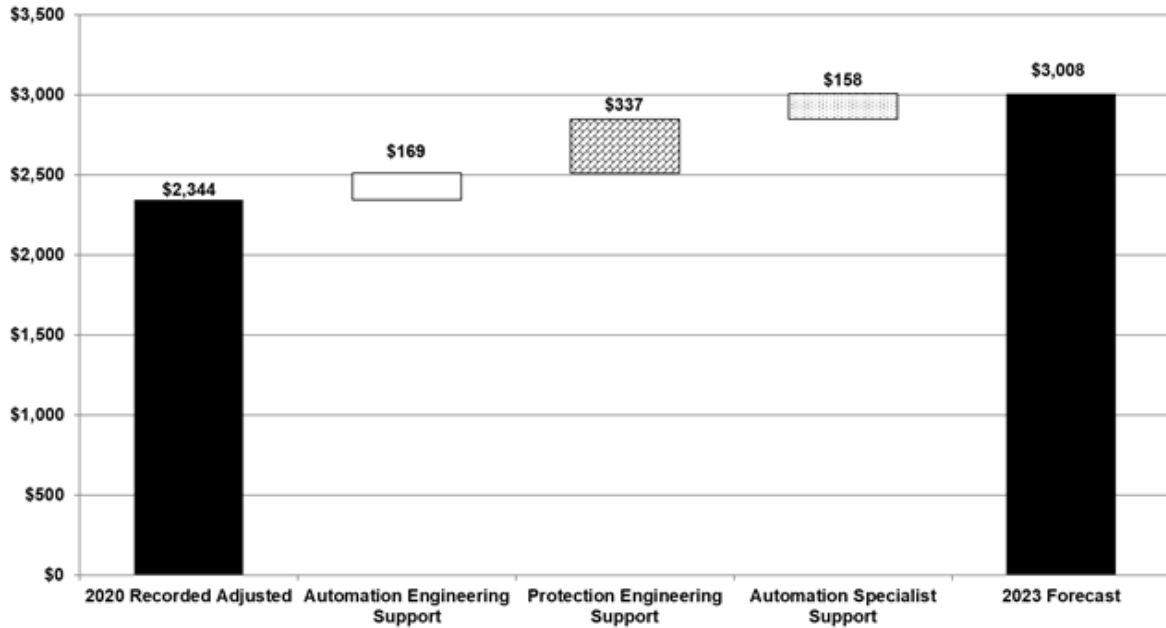
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**4** PG&E used MAT HXA solely for the purpose of running risk model as noted in Tables 16-2 and 16-3.

**5** Exhibit (PG&E-4), WP 16-5, line 5.

**6** Exhibit (PG&E-4), Ch. 7, Section C.1.c.

**FIGURE 16-1**  
**MWC HX EXPENSE WALK 2020-2023**  
**(THOUSANDS OF NOMINAL DOLLARS)**



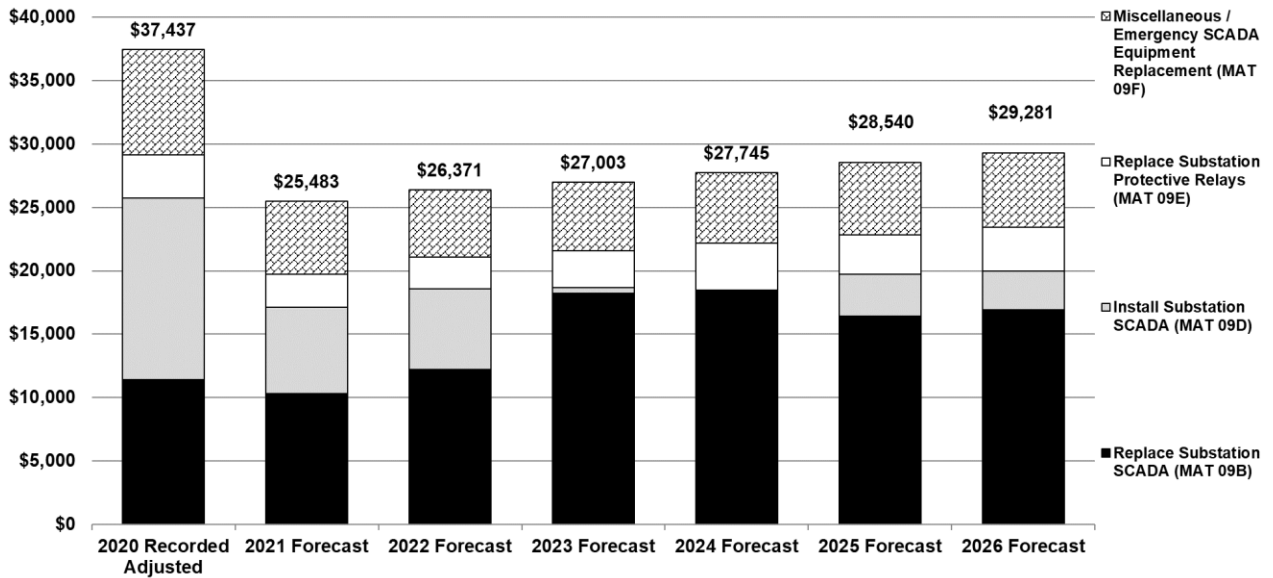
1           **b. Capital**

2           The capital expenditures PG&E forecasts in MWC 09 in this chapter  
3 will be used to: (1) install substation SCADA (MAT 09D); (2) replace  
4 substation SCADA (MAT 09B); (3) replace substation protective relays  
5 (MAT 09E); and (4) perform miscellaneous and emergency SCADA  
6 equipment replacements (MAT 09F). The install and replace distribution  
7 line SCADA program formerly forecast and recorded in MAT 09A has  
8 been moved to MAT 49A for this (GRC).<sup>7</sup> Figure 16-2 shows the  
9 2020-2026 DSAP Program capital forecast as compared to recorded  
10 expenditures. PG&E forecasts increases in the replacement of  
11 substation SCADA (MAT 09B) to address aging legacy devices, and  
12 decreases in installation of substation SCADA (MAT 09D) beginning in  
13 2020 as PG&E completes installation of SCADA in most distribution  
14 substations by the end of 2019.

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<sup>7</sup> Exhibit (PG&E-4), Ch. 4.3, Section C.3.a and Ch. 13, Section C.3.a.

**FIGURE 16-2**  
**DSAP**  
**MWC 09 CAPITAL RECORDED AND FORECAST BY SUBPROGRAM 2020-2026**  
**(THOUSANDS OF NOMINAL DOLLARS)**



1        **4. Support for Request**

2            Work in the DSAP Program supports the safe, reliable, efficient  
3            operation of ED substations. PG&E's capital and expense expenditure  
4            forecasts for the DSAP Program are reasonable because the Company:

- 5            • Manages its automation and protection equipment assets effectively to  
6            maintain safe and reliable service for PG&E customers;  
7            • Forecasts expenditures to replace aging and obsolete assets;  
8            • Provides efficiency and flexibility for electric operations (EO) by using  
9            SCADA;  
10            • Provides engineering support for the maintenance and operation of  
11            automation and protection equipment; and  
12            • Controls Risk Assessment and Mitigation Phase (RAMP) risk Failure of  
13            ED Overhead Assets.

14        **5. Organization of the Remainder of This Chapter**

15            This chapter will discuss the expense and capital program activities and  
16            costs associated with the DSAP program including estimating methods and  
17            costs. The remainder of this chapter is organized as follows:

- 18            • Section B – Program and Risk Overview;

- 1 • Section C – Activities, Costs, and Forecast Drivers by MWC;
- 2 • Section D – Compliance with Section 5.2 of the 2020 GRC Settlement
- 3 Agreement (“Deferred Work Principles”); and
- 4 • Section E – Cost Tables.

## 5 **B. Program and Risk Overview**

### 6 **1. Program Description**

#### 7 **a. Program Overview**

8 The DSAP Program covers the installation, upgrade, and  
9 replacement of remotely controlled automation and protection  
10 equipment in distribution substations. As PG&E has reached near  
11 100 percent substation SCADA penetration in 2019, the DSAP  
12 Program’s primary focus will shift to replacing obsolete SCADA and  
13 protection equipment. This work will improve operating efficiency,  
14 enable better outage response and diagnosis, improve system  
15 protection, and improve employee and public safety by enabling PG&E  
16 to automatically and remotely shut off electricity during emergencies as  
17 well as disabling circuit breaker reclosing during periods of high fire risk.

#### 18 **b. Management Structure**

19 PG&E’s Vice President (VP) of Asset Risk Management leads an  
20 organization responsible for the activities discussed in this chapter.  
21 A Senior Director of Electric Asset Strategy reports to the VP of Asset  
22 Risk Management. The Senior Director of Electric Asset Strategy  
23 oversees a team of Directors and Managers who lead the development  
24 of PG&E’s ED substation and storage strategies. These groups’ roles  
25 are to manage and improve the safety and reliability of PG&E’s electric  
26 assets. They partner with other PG&E departments and  
27 cross-functional teams to address electric infrastructure system needs,  
28 including system protection and automation.

29 The System Automation department, led by a Senior Manager,  
30 manages and executes the substation automation and protection  
31 programs covered in this chapter. Members of this group work with  
32 various PG&E groups to refine specific projects. Execution of the work

1 is coordinated by project managers and performed by PG&E employees  
2 and contract personnel.

### 3 **c. Key Metrics and Other Performance Measures**

4 Key metrics by which the various subprograms are measured within  
5 this chapter are categorized by completed and forecasted units. These  
6 unit measures are specific to each subprogram and are defined as  
7 follows:

- 8 • Replace Substation SCADA (MAT 09B) – The number of distribution  
9 Remote Terminal Units (RTU), Human Machine Interface (HMI) and  
10 circuit breaker intelligent electronic devices in which SCADA  
11 functionality is replaced;
- 12 • Install Substation SCADA (MAT 09D) – The number of distribution  
13 circuit breakers for which SCADA functionality is installed;
- 14 • Replace Substation Protective Relays (MAT 09E) – The number of  
15 distribution transformer protective packages replaced; and
- 16 • Miscellaneous/Emergency SCADA Equipment Replacement  
17 (MAT 09F) – No units are tracked because this subprogram  
18 represents unplanned emergency replacement work which varies  
19 significantly in scope.

## 20 **2. Risk Integration**

21 Chapter 3 of this exhibit describes how EO uses the Enterprise and  
22 Operational Risk Management program to manage electric system risks.  
23 Table 16-2 below shows the EO risk associated with the forecasts discussed  
24 in this chapter.

**TABLE 16-2  
RISKS DISCUSSED IN THIS CHAPTER**

Line No.	Risk Name	Risk ID	Type of Risk	MAT
1	Failure of ED Overhead Assets	DOVHD	RAMP	09B, 09D, 09E, 09F, HXA, HX#

1           **a. RAMP Risk – Failure of ED Overhead (OH) Assets**

2                   **1) Risk Overview**

3                   The Failure of ED OH Assets risk is defined as the failure of  
4                   distribution OH assets or lack of remote operation functionality that  
5                   may result in public or employee safety issues, property damage,  
6                   environmental damage, or inability to deliver energy. Failure of ED  
7                   OH Assets was one of PG&E’s 2020 RAMP risks.<sup>8</sup>

8                   In Chapter 3 of this Exhibit, PG&E described how management  
9                   of the Failure of ED OH Assets risk has changed since the filing of  
10                  the 2020 RAMP Report, listed each EO mitigation and control and  
11                  indicated if it has changed since the 2020 RAMP Report filing, and  
12                  provided updated Risk Spend Efficiency scores. In this chapter  
13                  PG&E provides more information about the control and the work  
14                  forecast in this chapter needed for implementation.

15                  **2) Risk Mitigations and Controls**

16                  As shown in the Table 16-3 below, PG&E has one control—  
17                  Supervisory Control and Data Acquisition—related to work forecast  
18                  in this chapter. This program was determined to reduce the  
19                  frequency or consequence of risk of failure of distribution substation  
20                  assets. A brief description of the control is provided in the table  
21                  below. More detail is included in the 2020 RAMP Report.<sup>9</sup>

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<sup>8</sup> PG&E’s RAMP Report (June 30, 2020), Ch. 11.

<sup>9</sup> PG&E’s RAMP Report (June 30, 2020), Ch. 11, starting at p. 11-14.

**TABLE 16-3  
FAILURE OF ED OH ASSETS  
FORECAST CONTROL**

Line No.	Control Number	Control Name	Description	Risk Drivers Addressed	Additional Information	MAT Code
1	DOVHD-C007	SCADA	Replace outmoded SCADA/RTU in ED substations to provide visibility and remote controllability to Operations; engineering support for the maintenance and operation of automation and protection equipment; upgrade/replace banks, relays and associated equipment; ED Sub Emergency replacement work.	Foundational	See Section C.1 for information on expense activities and C.2 for information on capital activities	09B, 09D, 09E, 09F, HXA, HX#

1                   **3) Changes to Controls**

2                   PG&E has not modified its portfolio of controls related to work  
3                   forecast in this chapter since filing the RAMP Report.

4                   In RAMP, PG&E described this control as including the  
5                   installation, upgrade and replacement of remotely controlled  
6                   automation and protection equipment in distribution substations and  
7                   on feeder circuits. PG&E has updated the definition to include  
8                   “circuit breakers” as part of the program to provide clarity.

9                   **4) Cost Tables**

10                  Forecast costs for the SCADA control are shown in  
11                  workpapers.<sup>10</sup>

12                  **C. Activities, Costs, and Forecast Drivers by MWC**

13                  **1. Expense – MWC HX**

14                  PG&E describes below the major expense drivers to the forecast shown  
15                  in Figure 16-1. Work in MWC HX includes engineering and technical  
16                  support for PG&E’s automation and protection equipment. In addition, it  
17                  includes the service and software costs associated with distribution  
18                  automation equipment. The engineering support consists of three key

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<sup>10</sup> Exhibit (PG&E-4), WP 3-9, line 32.

1 components: (1) Automation Engineering support; (2) Protection  
2 Engineering support; and (3) Automation Specialist support, which includes  
3 the wildfire risk mitigation including PSPS.

4 **a. Automation Engineering Support**

5 PG&E's 2023 forecast for Automation Engineering Support  
6 is \$0.8 million, which is \$0.2 million higher than 2020 recorded costs of  
7 \$0.6 million.<sup>11</sup> This minor increase is associated with a headcount  
8 increase to support PSPS and other emergent technology driven  
9 programs.

10 The Automation Engineering Support group assists operations and  
11 maintenance (O&M) teams with the implementation of substation  
12 automation equipment. This group works with engineering and  
13 construction groups to oversee substation automation projects and  
14 perform functions such as specifying RTU configurations and  
15 telecommunications requirements.

16 **b. Protection Engineering Support**

17 PG&E's 2023 forecast for Protection Engineering Support  
18 is \$1.6 million, which is \$0.3 million higher than 2020 recorded costs of  
19 \$1.2 million.<sup>12</sup> The increase is to review protective relay settings for  
20 distribution feeder circuits in support of PSPS, and provide support to  
21 perform annual audits on distribution feeders in order to capture  
22 efficiency and improve system reliability, annual training for distribution  
23 planners/operations, outage reviews, standards development, Rule 21  
24 compliance, DG support, mobile generators and islanding initiative.

25 The Protection Engineering Support group helps the O&M teams  
26 with the implementation of substation protection equipment. This group  
27 is responsible for relaying and protecting all distribution substation  
28 assets, including providing protection requirements for distribution  
29 automation projects, participating in substation project related on-site  
30 meetings, reviewing engineering drawings, and providing day-to-day  
31 support of protective systems, including PSPS.

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<sup>11</sup> Exhibit (PG&E-4), WP 16-5, line 1.

<sup>12</sup> Exhibit (PG&E-4), WP 16-5, line 2.

1           **c. Automation Specialist Support**

2           The Automation Specialist support group assists with the  
3           deployment, operation, and maintenance of distribution automation  
4           systems associated with the implementation of substation automation  
5           appliances including but not limited to HMIs.

6           Prior to 2020, PG&E recorded costs in MWC HX for SCADA  
7           Specialists. These SCADA Specialists programmed both SCADA and  
8           substation HMI. In 2020, the SCADA Specialists who work on SCADA  
9           were moved to the Business Applications department. Labor costs  
10          associated with their work are being recorded in MWC HG as of 2020  
11          and the forecast for that work is discussed in Distribution System  
12          Operations chapter of this exhibit.<sup>13</sup> The remaining SCADA Specialists,  
13          who work on substation HMI, have been reclassified as Automation  
14          Specialists; costs for these Automation Specialists continue to be  
15          recorded and forecast in MWC HX. PG&E's 2020 recorded costs in  
16          MWC HX also include the 2020 license fee for the RT-SCADA  
17          application; future RT-SCADA license fees will be funded from  
18          MWC HG.

19          PG&E's 2023 forecast in this area is \$0.7 million, which is  
20          \$0.2 million higher than 2020 recorded costs of \$0.5 million.<sup>14</sup> The  
21          increase is due to a small increase in headcount.

22           **d. Estimating Method**

23          PG&E developed its expense expenditures forecast based on  
24          historical data and anticipated labor forecast adjustments.

25           **2. Capital – MWC 09**

26          MWC 09 includes capital expenditures for installing new and replacing  
27          obsolete substation automation equipment and deficient protective relays.<sup>15</sup>  
28          PG&E is nearing 100 percent SCADA penetration in substations. As a

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

14 Exhibit (PG&E-4), WP 16-5, line 3.

15 The installation/replacement of new line SCADA, which was historically forecasted and recorded in MAT 09A, is now part of MAT 49A, which is discussed in Exhibit (PG&E-4), Ch. 4.3 and 13.

1 result, PG&E's forecast for new substation SCADA installation in MAT 09D  
2 is lower than in the past. However, PG&E forecasts increased lifecycle  
3 replacements in MAT 09B for this GRC period. PG&E describes below the  
4 major capital drivers to the forecast shown in Figure 16-2.

5 **a. Replace Substation SCADA (MAT 09B)**

6 A substation RTU is a microprocessor controlled electronic device  
7 located in a substation that controls and collects equipment operating  
8 information from various sensors, and then transmits it to one of PG&E's  
9 distribution control centers. A substation may contain multiple RTUs  
10 depending on the original installation design requirements and  
11 operational needs.

12 Because PG&E reached near 100 percent substation SCADA  
13 penetration in 2019, the DSAP Program's primary focus has shifted to  
14 replacing obsolete SCADA equipment. PG&E's existing substation  
15 SCADA system is composed of equipment from several companies, and  
16 includes RTUs and electronic components of various vintages, some as  
17 old as 25 years. A growing number of existing substation RTUs are  
18 either obsolete, reaching the end of their operational lives, or are not  
19 functional and cannot be repaired due to the unavailability of spare  
20 parts. As technology advances, it is often not feasible to maintain  
21 compatibility with these legacy RTUs when installing required new  
22 instrumentation and software. When a component of the SCADA  
23 system fails, it often jeopardizes PG&E's ability to operate the electric  
24 facility remotely and properly gather data for system operators.

25 Work in MAT 09B targets the replacement of obsolete RTUs;  
26 associated peripheral devices and circuit breaker protective relays within  
27 distribution substations may also be replaced to ensure compatibility  
28 with new automation systems. PG&E replaced 133 units in 30 electric  
29 substations throughout its service territory between 2016 and 2020.  
30 PG&E forecasts replacement of 392 legacy SCADA systems from 2021

1 to 2026 with an estimated average cost of \$211,000 per unit.<sup>16</sup> This  
 2 unit cost is a significant increase over the unit cost forecast in 2020  
 3 GRC due to the increased complexity of the projects.<sup>17</sup>

4 PG&E's forecast for MAT 09B is \$10.3 million in 2021, \$12.2 million  
 5 in 2022, \$18.2 million in 2023, \$18.5 million in 2024, \$16.4 million in  
 6 2025, and \$16.9 million in 2026.<sup>18</sup> PG&E's 2023 forecast is \$6.8 million  
 7 more than 2020 recorded capital expenditures of \$11.4 million.<sup>19</sup> The  
 8 increase is due to the need to proactively replace legacy substation  
 9 RTUs and associated peripheral devices to maintain SCADA system  
 10 reliability and Fault Location, Isolation and Service Restoration (FLISR)  
 11 scheme operability. The subprogram is primarily composed of projects  
 12 less than \$3 million.

13 **b. Install Substation SCADA (MAT 09D)**

14 PG&E's forecast for MAT 09D is \$6.8 million in 2021, \$6.3 million in  
 15 2022, \$0.5 million in 2023, \$3.0 thousand in 2024, \$3.3 million in 2025,  
 16 and \$3.0 million in 2026.<sup>20</sup> The 2023 forecast is \$13.8 million less than  
 17 2020 recorded capital expenditures of \$14.3 million.<sup>21</sup> The variance is  
 18 primarily due to the fact that PG&E's multi-year substation SCADA  
 19 installation program achieved nearly 100 percent completion by the end  
 20 of 2019. PG&E's 2021 and 2022 forecasts reflect the cost of projects  
 21 scheduled to be completed by 2023.<sup>22</sup> The 2023 forecast reflects  
 22 close-out costs associated with projects which are forecasted to become  
 23 operational in 2022 and earlier. The 2024-2026 forecasts are primarily

---

<sup>16</sup> Units are defined as the replacement work necessary to remove existing SCADA equipment and design, purchase, install and release fully operational remote control over a distribution feeder's circuit breaker, motor operator air switches and transformers.

<sup>17</sup> Exhibit (PG&E-4), WP 16-15, line 29, WP 16-16, and WP 16-18.

<sup>18</sup> Exhibit (PG&E-4), WP 16-12, line 1.

<sup>19</sup> Exhibit (PG&E-4), WP 16-12, line 1.

<sup>20</sup> Exhibit (PG&E-4), WP 16-12, line 2.

<sup>21</sup> Exhibit (PG&E-4), WP 16-12, line 2.

<sup>22</sup> Exhibit (PG&E-4), WP 16-12, line 2.

1 focused on the installation of SCADA at Oakland L Substation, a  
2 substation that does not currently have SCADA installed.<sup>23</sup>

3 PG&E has deployed SCADA at most of its substations, and  
4 proposes to continue these installations to further capture benefits and  
5 address a number of important issues. First, addressing public and  
6 system safety risk is PG&E's highest priority, and SCADA technology  
7 provides the ability for remote distribution operators to operate relays  
8 and quickly de-energize downed lines and equipment in support of  
9 wildfire risk management. Second, operational improvements are  
10 gained through remotely switching substation equipment, obtaining  
11 real-time information about the condition of the system, and providing  
12 historical data to examine line loading trends, forecast future loading,  
13 and perform outage investigations. Finally, substation SCADA  
14 deployments are foundational to Smart Grid technologies such as the  
15 deployment of FLISR to quickly and automatically restore customers'  
16 service after an outage. In 2020, PG&E installed SCADA on 50 circuit  
17 breakers at 15 PG&E substations throughout its service territory,  
18 increasing the distribution SCADA circuit breaker penetration from  
19 97.9 percent to 99.5 percent. PG&E plans to complete the remaining  
20 0.5 percent of circuit breakers in conjunction with programs in other lines  
21 of business such as asset management circuit breaker and switchgear  
22 replacement programs. There will continue to be forecasts in this  
23 subprogram to coordinate the installation of SCADA with other line of  
24 business programs. The majority of the subprogram is composed of  
25 projects less than \$3 million.

26 **c. Replace Substation Protective Relays (MAT 09E)**

27 MAT 09E covers the proactive replacement of aging substation  
28 protective relays. These relays serve the purpose of tripping substation  
29 circuit breakers when faults are detected, such as in cases of wires  
30 down resulting in over-current events. PG&E's forecast is \$2.6 million in  
31 2021, \$2.5 million in 2022, \$2.9 million in 2023, \$3.7 million in 2024,

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<sup>23</sup> Exhibit (PG&E-4), WP 16-14, line 1.

1 \$3.1 million in 2025, and \$3.4 million in 2026.<sup>24</sup> PG&E's 2023 forecast  
2 is \$0.5 million less than 2020 recorded capital expenditures of  
3 \$3.4 million.<sup>25</sup>

4 PG&E's distribution system has approximately 14,985 distribution  
5 electromechanical relays throughout its service territory in which  
6 approximately 2,408 are associated with distribution transformer  
7 protection with an average age of 27 years. It is estimated that poor  
8 performing relay types account for only 2 percent of the relay population  
9 but cause 32 percent of relay failure trips. Some driving factors are age  
10 of relays combined with other technical evaluation factors (e.g., Current  
11 Transformer saturation), criticality of the station, number of customers  
12 that could be affected, and type of customers. PG&E estimates that  
13 27 percent of the relay population is at or near the end of its service life  
14 and proposes to replace older mechanical relays with new  
15 microprocessor relays that have integrated protection, automation and  
16 control functionality. This integrated replacement approach allows for  
17 more cost-effective installation and testing, and standardizes design,  
18 which leads to better operability compared to separately installed  
19 systems. PG&E's System Protection Department manages a relay  
20 replacement list, and prioritizes replacements based on age and other  
21 technical evaluation factors including but not limited to criticality of the  
22 station, number of customers that could be affected, and type of  
23 customers.

24 PG&E expects that unit costs will remain similar to historical  
25 averages but is forecasting more units for the 2023 GRC cycle. PG&E  
26 proposes to replace protective relays on an average of 30 substation  
27 transformers annually from 2020 through 2026.<sup>26</sup>

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**24** Exhibit (PG&E-4), WP 16-12, line 3.

**25** Exhibit (PG&E-4), WP 16-12, line 3.

**26** Exhibit (PG&E-4), WP 16-17.

1           **d. Miscellaneous/Emergency SCADA Equipment**  
2           **Replacement (MAT 09F)**

3           The work in MAT 09F involves replacing inoperable automation and  
4           protection equipment (RTUs, peripheral boards, and protective relays)  
5           on an emergency basis. The forecast covers in-service failures as well  
6           as emergency replacements of equipment whose risk of failure is  
7           imminent. While PG&E's substation SCADA strategy is to proactively  
8           replace RTUs and associated equipment on a scheduled basis prior to  
9           failure (as part of work in MAT 09B discussed above), some  
10          unanticipated failures do occur requiring emergency replacement. The  
11          amount of work that PG&E needs to perform in this category is  
12          forecasted with historical failure expenditures in relation to the number  
13          of automation and protection devices in electric substation and feeder  
14          circuits.

15          PG&E's 2023 forecast of \$5.4 million is \$2.9 million less than 2020  
16          recorded expenditures of \$8.3 million.<sup>27</sup> PG&E's 2020 recorded  
17          expenditures were higher than forecast in the 2020 GRC and higher  
18          than historical trends; PG&E's 2023 forecast is consistent with a  
19          three-year (2018-2020) average of historical costs. PG&E's 2021  
20          forecast is \$5.8 million, 2022 forecast is \$5.3 million, 2024 forecast is  
21          \$5.6 million, 2025 forecast is \$5.7 million, and 2026 forecast is  
22          \$5.9 million.<sup>28</sup>

23           **e. Estimating Method**

24          PG&E developed its capital expenditures forecast based on  
25          determining the number of work units to be performed and multiplying  
26          them by the appropriate unit cost. Determining the number of units is  
27          based on program objectives, specific project requirements identified by  
28          field personnel, PG&E standards and guidelines, and estimates based  
29          on historical data, such as actual units completed. Asset Management

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<sup>27</sup> Exhibit (PG&E-4), WP 16-12, line 4.

<sup>28</sup> Exhibit (PG&E-4), WP 16-12, line 4.

1 determined the most appropriate unit cost to use in each case. Please  
2 refer to WPs for more details.<sup>29</sup>

3 **f. MWC 09 Forecast Summary**

4 Table 16-4 provides forecast capital expenditures for MWC 09 by  
5 sub-program.

---

<sup>29</sup> Exhibit (PG&E-4), WP 16-15, WP 16-16, and WP 16-18.

**TABLE 16-4**  
**MWC 09 CAPITAL EXPENDITURE RECORDED AND FORECAST**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Subprogram/Title	MAT Code	2020 Recorded Adjusted	Forecast					
				2021	2022	2023	2024	2025	2026
1	Replace Substation SCADA	09B	\$11,417	\$10,292	\$12,228	\$18,210	\$18,465	\$16,426	\$16,944
2	Install Substation SCADA	09D	14,307	6,841	6,329	470	3	3,301	3,040
3	Replace Substation Protective Relays	09E	3,399	2,580	2,540	2,908	3,714	3,100	3,430
4	Miscellaneous/Emergency SCADA Equipment Replacement	09F	8,314	5,769	5,274	5,416	5,563	5,713	5,867
5	Total		\$37,437	\$25,483	\$26,371	\$27,003	\$27,745	\$28,540	\$29,281

(PG&E-4)

1 **D. Compliance with Section 5.2 of the 2020 GRC Settlement Agreement**  
2 **(“Deferred Work Principles”)**

3 The 2020 GRC Settlement Agreement requires PG&E to include testimony  
4 in this GRC on deferred work if the following criteria are met:

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

11 For work covered in this Chapter, Check 1 was deemed to apply for all  
12 MWCs. Under PG&E’s analysis, Check 2 does not apply as work in this chapter  
13 is not unitized.

14 Work that was authorized in the 2020 GRC for MWCs in this chapter is  
15 needed to provide safe and reliable service, however there was not work that  
16 met the criteria for deferred work as described in the Settlement Agreement.  
17 This analysis is presented in the workpapers supporting Chapter 2 of this  
18 Exhibit.<sup>30</sup>

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19  
<sup>30</sup> Exhibit (PG&E-4) WP 2-13.

1 **E. Cost Tables**

2           The capital and expense forecasts for the DSAP Program are summarized  
3 in the following tables:

4           Table 16-5 below lists the expense MWC, showing 2016 through 2020  
5 recorded expenditures and 2021 through 2023 forecast expenditures.

6           Table 16-6 below lists the capital MWC, showing 2016 through 2020  
7 recorded expenditures and 2021 through 2026 forecast expenditures.

**TABLE 16-5  
EXPENSE  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded / Adjusted					Forecast			Workpaper Reference
			2016	2017	2018	2019	2020	2021	2022	2023	
1	HX	ED SAP	\$1,400	\$1,592	\$1,447	\$1,971	\$2,344	\$2,412	\$2,416	\$3,008	WP 16-1, line 1
2		Total	\$1,400	\$1,592	\$1,447	\$1,971	\$2,344	\$2,412	\$2,416	\$3,008	

**TABLE 16-6  
CAPITAL  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded / Adjusted					Forecast			Workpaper Reference			
			2016	2017	2018	2019	2020	2021	2022	2023		2024	2025	2026
1	09	ED SAP	\$56,243	\$52,745	\$64,365	\$56,508	\$37,437	\$25,483	\$26,371	\$27,003	\$27,745	\$28,540	\$29,281	WP 16-6, line 1
2		Total	\$56,243	\$52,745	\$64,365	\$56,508	\$37,437	\$25,483	\$26,371	\$27,003	\$27,745	\$28,540	\$29,281	

**PACIFIC GAS AND ELECTRIC COMPANY  
2023 GENERAL RATE CASE**

Testimony     X          Workpapers                           SOQ                     

Exhibit Number:     04          Chapter Number:     16    

Chapter Title:     Distribution System Automation and Protection    

Witness Name:     David Carroll    

Page No.	Line No.	Item	As Filed	As Corrected
<b>Errata as of November 5, 2021</b>				
16-4	Figure 16-2	2020 Recorded costs for MAT 09E reduced by \$1,619 from \$5,018 to \$3,399. 2020 Recorded costs for MAT 09F increased \$1,619 from \$6,695 to \$8,314. The total 2020 recorded costs do not change.	Replace Substation Protective Relays (MAT 09E): \$5,018K  Miscellaneous / Emergency SCADA Equipment Replacement (MAT 09F): \$6,695K	Replace Substation Protective Relays (MAT 09E): \$3,399K  Miscellaneous / Emergency SCADA Equipment Replacement (MAT 09F): \$8,314K
16-6, Table 16-2	1	DOVHD MAT Codes	MATs: 09B, 09D, 09E, 09F, HXA	MATs: 09B, 09D, 09E, 09F, HXA, HX#
16-6	15	Changed the word relay to package	"...transformer protective relay..."	"...transformer protective package..."
16-8, Table 16-3	1	DOVHD-C007 Risk Drivers	Substation Equipment Failure	Foundational
16-8, Table 16-3	1	DOVHD-C007 MAT Codes	MATs: 09B, 09D, 09E, 09F, HXA	MATs: 09B, 09D, 09E, 09F, HXA, HX#

16-14	2-3	Updated 2020 recorded costs	"...forecast is \$2.1...", "...of \$5.0..."	"...forecast is \$0.5...", "...of \$3.4..."
16-15	15-16	Updated 2020 recorded costs	"...is \$1.3...", "...of \$6.7..."	"...is \$2.9...", "...of \$8.3..."
16-15	20	Updated 2021 forecast	\$5.7	\$5.8
16-17	Table 16-4 3&4	2020 Recorded Adjusted costs for MAT 09E & 09F	MAT 09E: \$5,018 MAT 09F: \$6,695	MAT 09E: \$3,399 MAT 09F: \$8,314
16-17	Table 16-4 3&4	2021 Forecast for MAT 09E & 09F	MAT 09E: \$2,603 MAT 09F: \$5,747	MAT 09E: \$2,580 MAT 09F: \$5,769

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 17**  
**ELECTRIC DISTRIBUTION CAPACITY,**  
**ENGINEERING, AND PLANNING**  
**[INCLUDES NOVEMBER 5, 2021 ERRATA]**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 17  
ELECTRIC DISTRIBUTION CAPACITY,  
ENGINEERING, AND PLANNING

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1                                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2   **CHAPTER 17**  
3                                   **ELECTRIC DISTRIBUTION CAPACITY,**  
4                                   **ENGINEERING, AND PLANNING**

5   **A. Introduction**

6       **1. Scope and Purpose**

7           The purpose of this chapter is to demonstrate that Pacific Gas and  
8   Electric Company's (PG&E) expense and capital expenditure forecasts for  
9   its Engineering and Planning Program (Engineering and Planning Program)  
10   and its Electric Distribution Capacity Program (Capacity Program) are  
11   reasonable and should be adopted by the California Public Utilities  
12   Commission (CPUC or Commission). The Engineering and Planning  
13   Program supports a variety of asset management and operating activities  
14   and is necessary to plan, design, and operate PG&E's electric distribution  
15   system. PG&E uses the Capacity Program to manage substation and  
16   distribution line investments necessary to meet customer demand.  
17   The Commission's approval of this forecast will allow PG&E to fulfill its  
18   obligation to serve customers, meet regulatory and industry standards,  
19   cost-effectively mitigate equipment overload conditions, and provide safe  
20   and reliable service to customers.

21       **1. Summary of Request**

22           PG&E requests that the Commission adopt its 2023 expense forecast of  
23   \$19.9 million for the Engineering and Planning Program.<sup>1</sup> PG&E's 2023  
24   expense forecast is \$4.7 million higher than recorded expenses in 2020.<sup>2</sup>  
25   The purpose of this program is provide the engineering resources necessary  
26   to address increasing requirements by customers regarding the quantity and  
27   type of their electric service, increases in connected generation, and to  
28   support necessary improvements for an electric distribution infrastructure  
29   that is both aging and expanding. The Engineering and Planning Program

---

1   Exhibit (PG&E-4), WP 17-1, line 1.

2   Exhibit (PG&E-4) WP 17-1, line 1.

1 also supports distribution system improvements required to meet  
2 commitments in PG&E's Wildfire Mitigation Plan (WMP).

3 PG&E requests that the Commission adopt its capital expenditure  
4 forecasts of the Capacity Program of \$312.6 million in 2021, \$215.7 million  
5 in 2022, \$195.7 million in 2023, \$231.2 million in 2024, \$248.3 million in  
6 2025, and \$262.2 million in 2026.<sup>3</sup> The purpose of these expenditures is to  
7 upgrade or install new substation and distribution line equipment to serve  
8 the electric loads of new and existing customers. PG&E's 2023 forecast is  
9 \$52.2 million higher than its 2020 recorded costs of \$143.5 million.<sup>4</sup> The  
10 increase is primarily driven by an increase in new applications for service  
11 and added loads that require capacity work to serve, especially in the areas  
12 of transportation electrification, internet-based distribution centers, data  
13 centers, high tech campuses, state and local infrastructure, agricultural well  
14 pumping, dairy bio digesters, and indoor cultivation. The Capacity Program  
15 projects discussed in this chapter support the normal, emergency, and  
16 operational capacity necessary to satisfy customer load demands and  
17 reliability expectations. This includes off-peak analysis using recorded  
18 values to identify system needs associated with back flow from Distributed  
19 Energy Resources (DER).

20 The 2020 recorded expenditures of \$143.5 million for the  
21 Capacity Program were higher than the imputed authorized amounts from  
22 the 2020 General Rate Case (GRC) decision of \$124.5 million.<sup>5</sup> This is due  
23 to the completion in 2020 of capacity projects from previous years that were  
24 rescheduled due to emergency repair and wildfire hardening work as well as  
25 an increase in the number of new business applications for service that  
26 required capacity work to serve these loads.

27 Forecasts in this chapter are shown with escalation at the Major Work  
28 Category (MWC) level, and escalation is included in all MWC capital totals.  
29 For more information on escalation, please refer to Chapter 2 of this exhibit.

---

**3** Exhibit (PG&E-4), WP 17-6, line 3.

**4** Exhibit (PG&E-4), WP 17-6, line 3.

**5** See PG&E's 2020 Risk Spending Accountability Report for year 2020 (March 21, 2021), p. 3-3, lines 2 and 18. PG&E's MWC 46 2020 recorded amount in this GRC includes MAT 46# for the Renz Energy Storage project.

1       **2. Overview of Recorded and Forecast Costs**

2       **a. Expense (Engineering and Planning Program)**

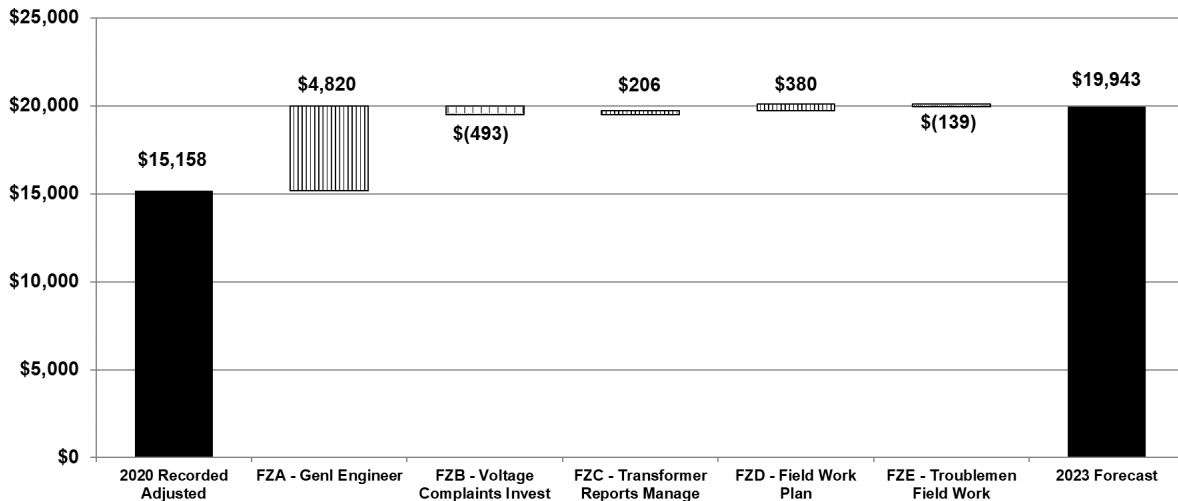
3               All expenses for the Engineering and Planning Program are  
4               recorded in MWC FZ, as shown in Table 17-1. Work in MWC FZ is  
5               further categorized into Maintenance Activity Type (MAT) codes, as  
6               described in Section C.1.

**TABLE 17-1  
ENGINEERING AND PLANNING MAJOR WORK CATEGORIES**

Line No.	MWCs	Description
1	<u>Expense MWC</u>	
2	FZ	Electric Engineering and Planning

7               Figure 17-1 below shows the expense walk from the 2020 recorded  
8               expense to the 2023 forecast by subprogram. The net increase in  
9               forecast costs as compared to recorded amounts is primarily due to  
10              increased Distribution Engineering headcount within MAT FZA (General  
11              Engineering) to facilitate local presence at the regional level and support  
12              increased workload.

**FIGURE 17-1  
ENGINEERING AND PLANNING PROGRAM  
EXPENSE WALK BY PROGRAM AREA 2020-2023  
(THOUSANDS OF NOMINAL DOLLARS)**



1                   The 2023 forecast for each program area is primarily based on 2020  
 2 recorded expenses, adjusted for escalation and forecast increases in  
 3 MAT FZA to account for higher distribution engineering headcount and  
 4 APC costs.

5 **b. Capital (Capacity Program)**

6                   All capital costs for the Capacity Program are recorded in MWC 06,  
 7 Distribution Line Capacity, and MWC 46, Distribution Substation  
 8 Capacity, as shown in Table 17-2.

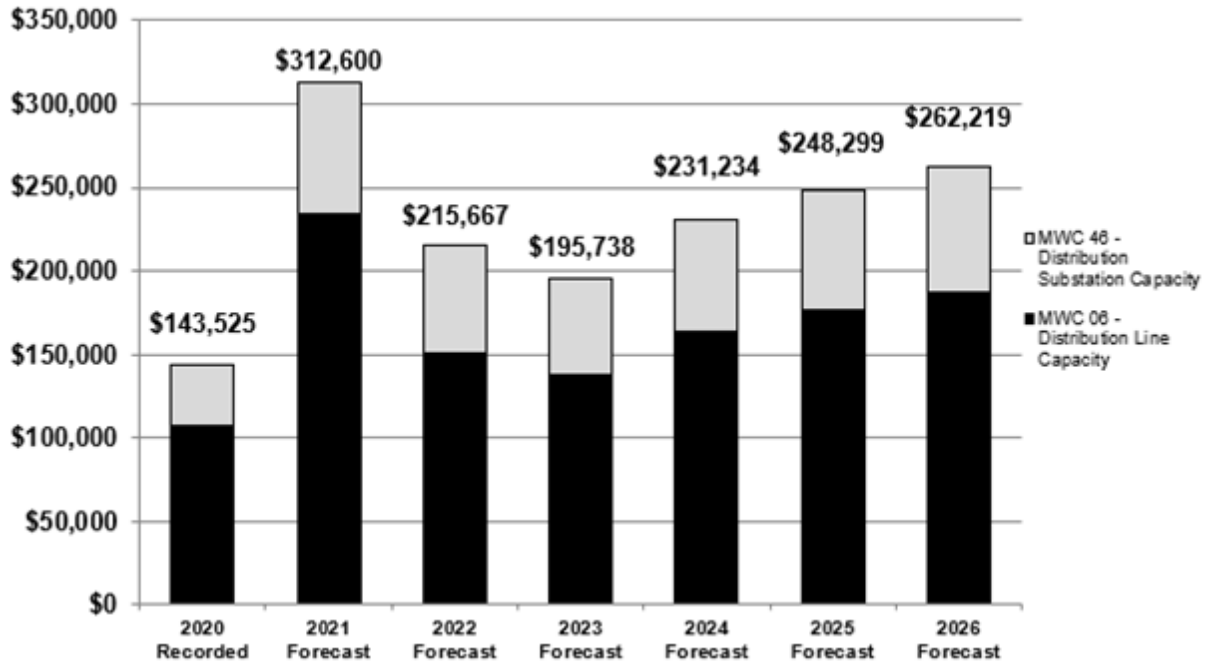
**TABLE 17-2  
DISTRIBUTION CAPACITY MAJOR WORK CATEGORIES**

Line No.	Capital MWCs	Description
1	06	Distribution Line Capacity
2	46	Distribution Substation Capacity

9                   Work in the Capacity Program is further categorized into MAT  
 10 codes, as described in Section C.2.

11                   Figure 17-2 shows PG&E’s 2020 recorded capital expenditures and  
 12 2021-2023 forecast capital expenditures by MWC.

**FIGURE 17-2  
CAPITAL RECORDED AND FORECAST BY MWC 2020-2026  
(THOUSANDS OF NOMINAL DOLLARS)**



1                   The key drivers of the increase in 2023 forecast spending over  
2                   2020 recorded amounts are as follows:

3                   In MWC 46, the increase is primarily driven by new applications for  
4                   service and added loads that require capacity work to serve industrial,  
5                   agricultural, and high-tech facilities as well as state and local  
6                   infrastructure. PG&E also anticipates additional capacity work to  
7                   support a substantial increase in electric vehicle (EV) fast charging and  
8                   fleet charging applications.

9                   In MWC 06, the increase is primarily driven by an anticipated  
10                  increase in emergent capacity work to serve new business applications,  
11                  a significant increase in the overloaded transformer replacement  
12                  program, and higher project costs.

13                  It should be noted that PG&E is not requesting approval in this GRC  
14                  for specific distribution capacity projects but is requesting funding for  
15                  overall distribution capacity needs based on the major work categories  
16                  associated with its overall forecast of loads and needs throughout the  
17                  system.

### 3. Support for Request

PG&E's expense forecast for the Engineering and Planning Program is reasonable to address increasing requirements by customers regarding the quantity and type of their electric service, increases in connected generation, and to support necessary improvements for an electric distribution infrastructure that is both aging and expanding. The Engineering and Planning Program also supports distribution system improvements required to meet commitments in PG&E's WMP.

PG&E's capital expenditure forecast for the Electric Distribution Capacity Program is reasonable because the forecast work:

- Is consistent with PG&E planning and design standards;
- Provides adequate capacity to meet Electric Rule 2 service requirements;
- Is efficiently managed through centralized program management; and
- Mitigates conditions that could negatively affect public and employee safety.

### 4. Organization of the Remainder of This Chapter

The remainder of this chapter is organized as follows:

- Section B – Program and Risk Overview;
- Section C – Activities and Costs, and Forecast Drivers by MWC;
- Section D – Compliance with Section 5.2 of the 2020 GRC Settlement Agreement (“Deferred Work Principles”); and
- Section E – Cost Tables.

## B. Program and Risk Overview

### 1. Program Description

#### a. Program Overview

The Engineering and Planning Program primarily covers electric distribution engineering and planning services labor which supports a variety of asset management activities. The Engineering and Planning Program provides support to capital expenditure programs such as Electric Distribution Capacity, Overhead Asset Management, Underground Asset Management, Distribution Reliability, Distribution Automation, Wildfire Risk Mitigation, Grid Modernization, Community

1 Rebuild, Rule 20A, and New Business and Work at the Request of  
2 Others (NB/WRO).

3 The key objectives of the Capacity Program are to address:  
4 (1) capacity expansion necessary to meet customer demand growth;  
5 (2) potential equipment overload conditions; and (3) voltage and power  
6 factor compliance requirements.

7 The Capacity Program's objectives and its procedures for identifying  
8 forecast work are generally the same as in the 2020 GRC and are  
9 described in the rest of this section.

10 Each year, PG&E analyzes the distribution summer peak electric  
11 demand by comparing future load forecasts against available capacity.  
12 This annual process begins after the yearly system peak has occurred,  
13 and after load forecasting is complete. Prior to proposing equipment  
14 upgrades, to the extent possible, overload or capacity deficiencies and  
15 low-voltage conditions are mitigated through available system  
16 reconfiguration, such as switching between substation transformers and  
17 circuits. PG&E then identifies specific capacity projects for the following  
18 3-5 years, and identifies annual work based on the system forecast.

19 The Capacity Program management process involves six general  
20 steps, described below:

21 **1) Identify Need**

22 PG&E's service territory consists of approximately  
23 3,200 feeders and 1,300 distribution substation transformers under  
24 the responsibility of ten local area planning groups. Each year, the  
25 area planning groups prepare load growth forecasting studies which  
26 include individual DER forecasts by feeder. These forecasts are  
27 used to identify equipment overloads and quantify capacity  
28 deficiencies. Using uniform capacity planning guidelines and  
29 engineering standards, the local area planning groups identify  
30 potential mitigations. The area planning groups also prepare  
31 detailed forecasts for the subsequent three years and provisional  
32 forecasts for large-scale individual capacity projects (such as  
33 substation transformer, distribution circuit, or other large projects to  
34 increase capacity) for years four and five. The projects forecast in

1 this chapter are based on PG&E's current load forecasting  
2 methodology. The current forecast incorporates the effect of  
3 existing DERs to the extent that DER load reduction is reflected in  
4 historical peak loads. All feeder load forecasts consider DER  
5 growth scenarios in future years.

6 System capacity deficiency projects identified during the  
7 2019 forecasting process were part of the 2020 Distribution  
8 Investment Deferral Framework (DIDF) and were the basis for the  
9 2020 Grid Needs Assessment (GNA) report issued by PG&E on  
10 August 15, 2020.<sup>6</sup> These projects will appear again in the  
11 2021 GNA report and be more fully developed and scoped than the  
12 newer emergent projects identified during the 2020 forecasting  
13 process. These emergent projects will be identified in the  
14 2021 GNA report to be issued by PG&E on August 15, 2021.  
15 Emergent projects are identified in a separate section of the  
16 Chapter 17 workpapers, WP 17-21, lines 86-123 and WP 17-22,  
17 lines 86-123 and have rough dates, scope, and forecasted dollars  
18 associated with them. These project attributes will be better defined  
19 and scoped by the time of the 2021 DIDF Filing. Emergent projects  
20 will be funded from the MAT 06H and MAT 46H emergent capacity  
21 buckets.<sup>7</sup>

22 In addition, changing customer needs can cause ongoing  
23 updates to the forecast, including New Business applications for  
24 single large customer service locations. As a result of these  
25 updates and new loads, the list and timing of projects discussed in  
26 the 2023 GRC Workpapers may change prior to the publication of  
27 the 2021 Distribution Deferral Opportunity Report (DDOR)<sup>8</sup> on  
28 August 15, 2021

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**6** See R.14-08-013; Electric Distribution Resources Plan 2015 OIR; PG&E's 2018 GNA Report.

**7** Exhibit (PG&E-4), WP 17-73 to WP 17-76.

**8** The GNA is the basis for the projects identified in the DDOR. The DDOR presents PG&E's planned investments that provide one or more of the distribution services adopted by D.16-12-036, as well as the resulting shortlist of candidate deferral projects after applying the initial deferral screens to the planned investments.

## 2) Evaluate Alternatives

Many larger distribution line projects and most substation projects generally have more than one alternative for mitigating an overload condition, including potential DERs that meet PG&E's reliability, operating, and safety criteria within the affected local planning areas. Project initiation starts with a detailed analysis of the cost and system benefit of various alternatives. Generally, substation equipment upgrades are multi-year projects that require three years or more to design, procure the necessary material, and construct, though some minor substation upgrades take less time. New substations generally take 5-7 years to build, due to permitting requirements.<sup>9</sup>

### a) Evaluate DER Alternatives

As part of the annual DIDF, each capacity deficiency identified for a given equipment upgrade project is screened for potential DER deployment. Timing, cost effectiveness, and forecast uncertainty are all used to identify projects that may present good DER deferral opportunities. Candidates for DER deferral are reviewed by the Distribution Planning Advisory Group (DPAG), which provides advisory input on the selection of projects to be considered for DER deferral.

The Commission has adopted cost recovery standards that address how the costs of PG&E's distribution capacity projects included in a GRC will be recovered if those projects become subject to potential or actual deferral by DER projects procured by PG&E under its Distribution Resources Plan. Under the Commission's guidelines, PG&E tracks existing DER contract payments for deferral of distribution capacity projects in its Distribution Deferral balancing account for recovery in its next

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<sup>9</sup> Detailed alternatives for projects beyond the 3-year window are generally evaluated for new substation projects only. Detailed analysis of out years for other capacity projects that are not expected to incur significant expenditures in the near-term would be premature because the distribution system is dynamic; forecast deficiencies may not materialize and the system may change for other reasons.

1 GRC. Neither DER payments nor the avoided costs of  
2 traditional investments are reduced from previously adopted  
3 revenue requirements in PG&E's prior GRCs. If PG&E includes  
4 a specific distribution capacity project in its GRC capital request  
5 at the same time the project is being considered as a DER  
6 candidate deferral project, the Commission may consider  
7 adjusting PG&E's GRC revenue requirement to reflect any  
8 savings from the DER deferral project. Where the Commission  
9 approves a DER project to defer a specific investment that has  
10 been explicitly approved in PG&E's most recent GRC (and is  
11 included in PG&E's GRC revenue requirement), PG&E may  
12 recover these costs through its GRC revenues, and may not  
13 book payments for the corresponding DER project to its  
14 Distribution Deferral balancing account. Such a cost recovery  
15 criteria only applies through the DER contract period during  
16 which PG&E collects a revenue requirement for the approved  
17 traditional investment.

18 On November 16, 2020, PG&E filed Advice Letter 6003-E to  
19 inform the CPUC that seven capacity projects were considered  
20 candidates for DER deferral and that PG&E recommended  
21 pursuing competitive solicitations for all seven projects.  
22 Ultimately, PG&E did not receive enough offers to meet the full  
23 grid need at any deferral location. Therefore, PG&E has  
24 decided to conclude the first phase of the 2020 DIDF.

25 **3) Estimate Costs**

26 Based on project alternatives being evaluated, the area  
27 planning groups then develop project cost estimates. For most  
28 projects, the area planners develop costs using either estimates of  
29 specific equipment and unit costs for work required, or historical  
30 costs from completed projects.

31 **4) Project Consolidation and Prioritization**

32 Projects from the ten area planning groups are consolidated for  
33 evaluation and prioritization. With input from Staff Engineers and

1 other Managers, a Lead Engineer reviews each project and  
2 examines the historic spending trends of the smaller recurring  
3 projects. The Lead Engineer assesses projects based on the  
4 forecast deficiency or overload, as well as costs, then makes  
5 preliminary scheduling and budgeting recommendations for both  
6 large projects (e.g., substation transformers and distribution circuits)  
7 and smaller recurring projects (e.g., voltage complaints,  
8 reconductoring projects, and overloaded distribution line  
9 transformers).

10 **5) Finalize Plan**

11 After further evaluation of the preliminary plan, supplemented by  
12 any new information from the local planning groups and the DPAG,  
13 the Lead Engineer develops a detailed plan for the subsequent  
14 three years and a provisional plan for years four and five. This plan  
15 is then provided to the work execution teams for implementation.

16 **6) Ongoing Evaluation**

17 The funding plan is reprioritized as required throughout the year  
18 to: (1) confirm completion of high priority work; (2) monitor spending;  
19 and (3) maintain an accurate forecast of year-end expenditures.  
20 Depending on the timing of a potential DER deferral opportunity, a  
21 contingency plan may be required to ensure the system can meet  
22 the capacity need if further evaluation determines the DER  
23 opportunity cannot meet the needs of the system, or if the selected  
24 opportunity does not obtain the necessary approval.

25 **b. Management Structure**

26 The Engineering and Planning Program is part of the Asset Risk  
27 Management Department in Electric Operations. Engineering and  
28 Planning Program employees, who carry the title of Electric Distribution  
29 Engineer, focus on:

- 30 • Performing engineering analysis to support capital project needs for  
31 Electric Distribution Capacity, Overhead Asset Management,  
32 Underground Asset Management, Distribution Reliability,

1 Distribution Automation, Wildfire Risk Mitigation, Grid Modernization,  
2 Community Rebuild, Rule 20A, NB/WRO, and operations;

- 3 • Performing studies, based on customer requests, to interconnect
- 4 DERs to PG&E's distribution system;
- 5 • Responding to customer inquiries regarding electric and magnetic
- 6 fields and reliability problems;
- 7 • Providing protective device settings and voltage control device
- 8 settings for equipment installations; and
- 9 • 10-year protection reviews.

10 PG&E's Vice President (VP) of Asset Risk Management leads the  
11 organization responsible for the Capacity Program investment plan. The  
12 Director of Asset Planning reports to this VP. Two Managers of Electric  
13 Distribution Planning report to the Director of Asset Planning. The  
14 ten local area planning groups and other Staff Engineers collectively  
15 report to these Managers and work together to identify deficiencies,  
16 configuration changes, and capital projects, as necessary, to maintain  
17 distribution system integrity.

### 18 c. Key Metrics and Other Performance Measures

19 The Engineering and Planning Program primarily covers electric  
20 distribution engineering and planning services labor and therefore does  
21 not include any specific key metrics.

## 22 2. Risk Integration

23 Chapter 3 of this exhibit describes how Electric Operations (EO) uses  
24 the Enterprise and Operational Risk Management (EORM) Program to  
25 manage electric system risks. Table 17-3 below shows the EO risks  
26 associated with the forecasts discussed in this chapter.

**TABLE 17-3  
RISKS DISCUSSED IN THIS CHAPTER**

Line No.	Risk Name	Risk ID	Type of Risk	MAT
1	Failure of Distribution Overhead Assets	DOVHD	RAMP	FZA, 06B

1           **a. RAMP Risk – Failure of Distribution Overhead Assets**

2                   **1) Risk Overview**

3                   The Failure of Electric Distribution Overhead Assets risk is  
4                   defined as the failure of distribution overhead assets or lack of  
5                   remote operation functionality may result in public or employee  
6                   safety issues, property damage, environmental damage, or inability  
7                   to deliver energy. Failure of Electric Distribution Overhead Assets  
8                   was one of PG&E’s 2020 RAMP risks.<sup>10</sup>

9                   In Chapter 3 PG&E describes how management of the risk has  
10                  changed since the filing of the 2020 RAMP Report; lists each  
11                  mitigation and control, indicating if it has changed since the  
12                  2020 RAMP Report filing; and provides updated RSEs. In this  
13                  chapter PG&E provides more information about the controls related  
14                  to work forecast in this chapter and the work needed to implement  
15                  them.

16                   **2) GRC Risk Mitigations and Controls**

17                  As shown in the tables below, PG&E is forecasting two controls  
18                  related to work forecast in this chapter. PG&E is not forecasting any  
19                  mitigations related to work forecast in this chapter. The control  
20                  programs were determined to reduce the frequency or consequence  
21                  of risk of failure of electric distribution overhead assets. A brief  
22                  description of these controls is provided in the table below. More  
23                  detail is included in the 2020 RAMP Report.<sup>11</sup>

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<sup>10</sup> Application (A.) 20-06-012, PG&E’s 2020 RAMP Report, Ch. 11.

<sup>11</sup> A.20-06-012, Controls and Mitigations, starting at p. 11-14.

**TABLE 17-4  
FAILURE OF DISTRIBUTION OVERHEAD ASSETS  
FORECAST CONTROLS**

Line No.	Control Number	Control Name	Description	Risk Drivers Addressed	Additional Information	MAT Code
1	DOVHD-C008	Annual Protection Reviews	This engineering program primarily covers electric distribution engineering and planning work which supports a variety of asset management activities and is necessary to safety and reliably plan, design, and operate PG&E's electric distribution system. General engineering work includes reviews of distribution system protection equipment and settings to ensure the devices will operate correctly and in a coordinated fashion.	Foundational	See Section C.1.a. below for more information	FZA
2	DOVHD-C09A	Overloaded Transformers Replacement	Replacement of transformers identified through overload reports using SmartMeter™ data, recorded high oil temperature indicators, or multiple thermal protective device operations during peak load periods. This does not include replacement of transformers identified via NB/WRO or any other process.	D-Line Equipment Failure	See Section C.2.b.2 below for more information	06B

### 3) Changes to Controls

Since filing the 2020 RAMP Report, PG&E modified its portfolio of controls related to work forecast in this chapter by removing a control related to Electric Distribution Line Operational Capacity Projects which was discussed in the 2020 RAMP as (DOVHD-C09B). PG&E has concluded that this control does not materially reduce risk of asset failure, though it does improve operational functionality and the ability to deliver power under abnormal conditions. This control has been excluded from the GRC.

### 4) Cost Tables

Forecast costs for controls are shown in supporting workpapers.<sup>12</sup>

## C. Activities, Costs, and Forecast Drivers by MWC

### 1. Expense (MWC FZ)

All the expense work discussed in this chapter relates to the Engineering and Planning program and is tracked in five MATs within MWC FZ. PG&E describes these five MATs and the major expense drivers to the forecast below. These MATs are listed in order of the walk shown in Figure 17-1.

#### a. General Engineering (MAT FZA)

General engineering work primarily covers electric distribution engineering and planning services labor required to support many types of projects such as capacity, NB/WRO, generation interconnection, reliability, overhead asset management, underground asset management, grid modernization, community rebuild, and wildfire risk mitigation. This engineering labor also covers developing electronic control settings for protective and voltage support equipment, as well as responding to customer inquiries regarding electromagnetic field (EMF) and reliability concerns.

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<sup>12</sup> Exhibit (PG&E-4), WP 3-9, line 33.

1           General engineering also includes the Asset Performance Center,  
2           which performs diagnostics on data from automated field equipment to  
3           support PG&E's Distribution Control Centers and wildfire risk mitigation  
4           activities.<sup>13</sup>

5           PG&E's 2023 forecast for MAT FZA is \$16.7 million, which is  
6           \$4.8 million higher than 2020 recorded costs of \$11.9 million.<sup>14</sup> The net  
7           increase, relative to recorded amounts, is primarily due to escalation  
8           and additional Distribution Engineering headcount.

9           The increase in Distribution Engineering headcount is to facilitate  
10          local presence at the regional level and support increased workload  
11          which created the need for two additional engineering planning offices to  
12          improve local engineering presence and accountability.

13          **b. Voltage Complaint Investigation (MAT FZB)**

14          Voltage complaint investigation work involves investigating  
15          secondary voltage complaints that Troublemakers cannot resolve on the  
16          first visit and setting recording voltage meters to measure the actual  
17          voltage at the sites underlying these voltage complaints. PG&E's  
18          2023 forecast in this area is \$0.6 million, which is \$0.5 million less than  
19          2020 recorded costs which were unusually high relative to historical  
20          spending.<sup>15</sup>

21          **c. Transformer Reports Management (MAT FZC)**

22          Transformer reports management work involves investigating  
23          potentially overloaded distribution line transformers. PG&E's  
24          2023 forecast for this work is \$0.2 million to cover any investigations  
25          required to support the Capacity Program MAT 06B, and any various  
26          unplanned investigations.<sup>16</sup>

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<sup>13</sup> See Exhibit (PG&E-4), Ch. 4.3, section C.3.c.1 for a more detailed discussion of the APC's activities and associated forecast.

<sup>14</sup> Exhibit (PG&E-4), WP 17-5, line 1.

<sup>15</sup> Exhibit (PG&E-4), WP 17-5, line 2.

<sup>16</sup> Exhibit (PG&E-4), WP 17-5, line 3.

1           **d. Field Work Plans (MAT FZD)**

2                     Field work plans involves supporting operational field work initiated  
3                     by engineering personnel, such as phase balancing, and replacing fuses  
4                     that are projected to be overloaded. PG&E's 2023 forecast in this area  
5                     is \$0.8 million, which is \$0.3 million higher than 2020 recorded costs of  
6                     \$0.5 million.<sup>17</sup> The net increase relative to recorded amounts is  
7                     primarily due to an increase in phase balancing work.

8           **e. Troublemens Field Work (FZE)**

9                     Troublemens field work includes implementing load transfers, control  
10                    device setting changes/downloads, and other specific field  
11                    investigations. PG&E's 2023 forecast in this area is \$1.5 million,  
12                    which is roughly equivalent to 2020 recorded amounts.<sup>18</sup>

13           **f. Estimating Method**

14                    The forecasts in MWC FZ are generally based on historical average  
15                    spending, with adjustments for areas where PG&E is expecting  
16                    increased spending (e.g., increased headcount in MAT FZA to facilitate  
17                    local presence at the regional level and support increased workload,  
18                    additional transformer investigation work in FZC, additional phase  
19                    balancing work in FZD). PG&E has also incorporated a cost-savings  
20                    initiative into MWC FZ for years 2021 and 2022.<sup>19</sup>

21           **g. MWC FZ Forecast Summary**

22                    Table 17-5 summarizes 2020 recorded expenditures and 2021-2023  
23                    forecasts for MWC FZ.

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<sup>17</sup> Exhibit (PG&E-4), WP 17-5, line 4.

<sup>18</sup> Exhibit (PG&E-4), WP 17-5, line 5.

<sup>19</sup> As explained in Exhibit (PG&E-2) Ch. 3, PG&E prepared its 2023 GRC forecast, starting first with the Plan of Reorganization forecast for the work included in the 2023 GRC and then adding updates to address company-wide work needs and priorities, risk mitigations, and cost-savings initiatives. Through the process of prioritizing the Electric Distribution portfolio and in accordance with the 2023 GRC forecast guidelines outlined in Exhibit (PG&E-2) Ch. 3, this forecast prioritizes funding for the most critical work and incorporates a cost-savings initiative which is identified as a reduction to the forecast. EO's work portfolio planning and prioritization process is discussed further in Exhibit (PG&E-4) Ch. 2.

**TABLE 17-5**  
**MWC FZ RECORDED AND FORECAST EXPENSES 2020-2023**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Work Description	MAT Code	2020				Workpaper Reference
			Recorded Adjusted	2021 Forecast	2022 Forecast	2023 Forecast	
1	General Engineering Voltage Complaint	FZA	\$11,877	\$14,574	\$14,367	\$16,696	WP 17-5, line 1
2	Investigations	FZB	1,127	607	608	645	WP 17-5, line 2
3	Transformer Reports Management	FZC	28	117	117	234	WP 17-5, line 3
4	Field Work Plans	FZD	468	798	799	848	WP 17-5, line 4
5	Troublemens Field Work	FZE	1,658	1,430	1,432	1,519	WP 17-5, line 5
6	Miscellaneous	FZ#	—	(2,078)	(1,168)	—	WP 17-5, line 6
7	MWC FZ Total		\$15,158	\$15,447	\$16,155	\$19,943	

## 1      **2. Capital MWCs**

2            The capital work described in this chapter all relates to PG&E's Capacity  
3 Program. Mitigations of capacity deficiencies require expansion of  
4 substation assets, distribution line and equipment assets, or both.  
5 PG&E records expenditures for work within substations in MWC 46, and for  
6 work outside of substations (including the circuit outlets from the substation  
7 equipment) in MWC 06. Project Summaries are included in the workpapers  
8 for projects with expenditures totaling greater than \$3 million.

9            The following sections address the specific forecasts for MWCs 46  
10 and 06 and discuss drivers for each MAT category within those MWCs.

### 11      **a. Distribution Substation Capacity (MWC 46)**

12            Work in MWC 46 consists of upgrades to various pieces of  
13 distribution substation equipment that are forecast to have a capacity  
14 deficiency. PG&E's capital expenditure forecast for MWC 46 in this  
15 chapter includes work in the following six MATs:

- 16            • Normal Capacity Deficiencies (MAT 46A and 46#);
- 17            • Emergency and Operational Capacity (MAT 46F);
- 18            • New Business-Related (MAT 46H);
- 19            • Land Purchase and New Distribution Substation (MAT 46N); and

- Support of Transmission and Substation-Related Work (MAT 46T).<sup>20</sup>

PG&E’s forecast for Distribution Substation Capacity in MWC 46 is \$78.9 million in 2021, \$65.2 million in 2022, \$58.0 million in 2023, \$68.0 million in 2024, 72.0 million in 2025, and \$74.7 million in 2026.

PG&E’s 2023 forecast is \$22.4 million more than 2020 recorded expenditures of \$36.3 million.<sup>21</sup> The increase is largely driven by:

- A marked increase in the number of EV fast charging and fleet charging applications for service that require capacity work to serve new load;
- An increase in new applications for service and added load, especially in the areas of internet delivery distribution centers, data centers, high tech campuses, state and local infrastructure, agricultural well pumping, dairy bio digesters, and indoor cultivation customers that require capacity work to serve new load;
- An increasingly high level of utilization of existing assets, which PG&E anticipates will result in more capacity work to serve new applications for service. In 2017 there were 167 banks and 323 circuits loaded above 90 percent. In 2020, this number had risen to 185 banks and 345 circuits; and
- Higher than historical costs for comparable work.<sup>22</sup>

A summary of the forecast expenditures for all distribution substation capacity work in MWC 46 is in Table 17-6 at the end of this section.

### 1) Normal Capacity Deficiencies (MAT 46A and 46#)

MAT 46A includes projects to support general distribution substation capacity increases. MAT 46# includes a portion of

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<sup>20</sup> This MAT code structure is the same one used in the 2020 GRC. Prior to the 2020 GRC, MWC 46 MAT assignments were based on the type of equipment identified for replacement rather than the type of capacity project, which resulted in a mix of justification drivers within each MAT. The current MAT categories are organized to better align with project justification supporting the work.

<sup>21</sup> Exhibit (PG&E-4), WP 17-16, line 9.

<sup>22</sup> Exhibit (PG&E-4), WP 17-16, line 9.

1 historic spend for the Renz Energy Storage project.<sup>23</sup> PG&E's  
2 forecast for MAT 46A and 46# is \$34.8 million in 2021, \$28.9 million  
3 in 2022, \$15.8 million in 2023, \$8.3 million in 2024, 5.6 million in  
4 2025, and \$0.8 million in 2026. PG&E's 2023 forecast is  
5 \$8.7 million higher than its 2020 recorded capital expenditures of  
6 \$7.1 million.<sup>24</sup> PG&E's spending in 2020 was relatively low,  
7 because fewer MAT 46A projects were completed so that funding  
8 could be moved to MAT 46H to support New Business capacity  
9 projects to cover an increasing number of customer applications.

10 Normal capacity deficiencies are identified based on peak  
11 forecast load or off-peak forecast back-flow compared to normal  
12 capacity ratings of the various pieces of substation equipment.  
13 The 2023 GRC forecast is driven by specifically identified projects.  
14 The number of normal capacity projects may increase due to future  
15 substation transformer capacity de-rates required to reduce loading  
16 of aging and deteriorated substation transformers and voltage  
17 regulators. Any future transformer de-rates will reduce available  
18 substation transformer capability and may require additional  
19 projects, which would be funded from emergent dollars to address  
20 newly created deficiencies

21 The MAT 46A forecast includes the Renz Energy Storage  
22 project to mitigate the forecast overload of Llagas Bank 3 by  
23 installing energy storage to offset demand and reduce loading. The  
24 Renz Energy Storage project has a forecast in MWC 46A of  
25 \$26.3 million in 2021 and \$0.2 million in 2022.<sup>25</sup> The Renz Energy  
26 Storage project will capture the market value of this resource when it  
27 is not prioritized to provide distribution reliability services, and to use  
28 that value to reduce the costs that will be borne by customers.

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**23** In the 2020 GRC, the Renz Energy Storage project was called the Llagas Energy Storage Project.

**24** Exhibit (PG&E-4), WP 17-16, lines 1 and 2.

**25** Exhibit (PG&E-4), WP 17-20, Table 17-18, line 62.

## 2) Emergency and Operational Capacity (MAT 46F)

MAT 46F includes: (1) work to address emergency capacity deficiencies; and (2) operational capacity work to reduce the number of customers on a circuit to no more than 6,000 and circuit loading to a maximum of 600 amperes (amps).

PG&E's forecast for MAT 46F is \$17.8 million in 2021, \$8.8 million in 2022, \$1.0 million in 2023, \$3.2 million in 2024, \$5.0 million in 2025, and \$0 in 2026. PG&E's 2023 forecast is \$10.9 million less than 2020 recorded capital expenditures of \$11.9 million.<sup>26</sup> The decrease is primarily due to the planned completion of MAT 46F projects identified in the 2020 GRC and PG&E's decision to prioritize New Business-related capacity projects over the identification of new MAT 46F-type projects for the 2023 GRC period.

### a) Emergency Capacity

Substation emergency capacity deficiencies occur when a transformer is removed from service during an unplanned event, and the remaining capacity is insufficient to serve the load.<sup>27</sup>

Projects identified to mitigate emergency deficiencies will:

- Reduce the risk of an extended outage to a critical piece of substation equipment in an urban and suburban area;
- Improve operating and maintenance flexibility;
- Provide a buffer for instances when actual peak loads exceed forecast peaks; and
- Reduce reliance on mobile transformers, which can take up to 24 hours to install.

The one new project<sup>28</sup> included in this GRC forecast has been evaluated based on current forecasts and has an

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<sup>26</sup> Exhibit (PG&E-4), WP 17-16, line 3.

<sup>27</sup> An emergency deficiency exists when the forecast peak load exceeds the available emergency capacity with the largest "non-firm" substation transformer removed from service. A substation transformer is considered "non-firm" if there is no spare transformer available to be placed into service at the substation during an emergency.

<sup>28</sup> Exhibit (PG&E-4), WP 17-19, Table 17-18, line 68; and, WP 17-53 to WP 17-56.

1 emergency deficiency of 14.9 megawatts (MW) if the largest  
2 transformer at the substation is lost. The customer count  
3 associated with this emergency deficiency is 2,214 customers.  
4 Three other emergency capacity projects included in the  
5 forecast are ongoing projects, with forecast completion dates in  
6 2021, that were previously included in 2020 GRC.

7 **b) Operational Capacity – Reduce Customer Count**

8 Operational capacity projects are identified to increase  
9 reliability by providing additional capacity in strategic locations  
10 to improve system flexibility to switch load between feeders and  
11 during planned clearance or outage events. The forecast  
12 includes projects to limit the number of customers on a circuit to  
13 no more than 6,000 and projects to maintain circuit loading to a  
14 maximum of 600 amps. Feeders that serve large numbers of  
15 customers or are highly loaded pose two issues: (1) a large  
16 number of customers are affected when an outage occurs, due  
17 to a circuit breaker opening; and (2) typical loading limits on  
18 adjacent circuits could hinder the ability to reconfigure highly  
19 loaded circuits. These issues negatively affect both customer  
20 outage frequency and duration.

21 Project work to address capacity deficiencies also  
22 contributes to greater switching flexibility, which enables  
23 location-specific reductions in customer counts by feeder.  
24 The three substation projects included in this GRC forecast are  
25 necessary to reduce the number of customers served by  
26 feeders located in urban or suburban areas and enable an  
27 average reduction of roughly 1,200 customers per feeder.<sup>29</sup>  
28 All three of the substation projects were included in 2020 GRC,  
29 with projected completion dates between 2020 and 2022.  
30 PG&E currently estimates that these projects will be completed  
31 in 2021 and 2022.

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<sup>29</sup> Exhibit (PG&E-4), WP 17-20, lines 3, 4, and 25; and, WP 17-57 to WP 17-60 (list of projects at WP 17-58, Project Description Table).

1                   **c) Operational Capacity – Reduce High Loading**

2                   Project work to reduce loading on feeders to 600 amps or  
3                   less also helps maintain operational flexibility in the system.  
4                   Typically, most feeders in PG&E’s system have a maximum  
5                   capacity limit of 600 amps or less due to standard equipment  
6                   limitations. As of the end of 2020, 49 of PG&E’s approximately  
7                   3,200 feeders were loaded to more than 600 amps. These  
8                   highly-loaded circuits constrain switching flexibility to adjacent  
9                   circuits for planned or unplanned outage events. There are  
10                  three substation jobs of this type included in the MAT 46F  
11                  forecast.<sup>30</sup> All three of the projects were included in 2020 GRC,  
12                  with projected completion dates between 2021 and 2022.  
13                  PG&E currently estimates that these projects will be completed  
14                  in 2022 and 2023.

15                  **3) New Business-Related Capacity (Includes Emergent Work**  
16                  **Program and Electrification Capacity) (MAT 46H)**

17                  MAT 46H includes projects which address capacity deficiencies  
18                  for New Business customer demand increases. PG&E’s forecast for  
19                  MAT 46H is \$26.2 million in 2021, \$27.5 million in 2022,  
20                  \$41.4 million in 2023, \$56.5 million in 2024, \$61.4 million in 2025,  
21                  and \$73.9 million in 2026. PG&E’s 2023 forecast is \$24.1 million  
22                  more than 2020 recorded capital expenditures of \$17.2 million.<sup>31</sup>  
23                  The increase is largely driven by identified projects (based on new  
24                  business applications for service) to provide capacity for internet  
25                  delivery distribution centers, data centers, high-tech campuses,  
26                  state and local infrastructure, agricultural well pumping, and indoor  
27                  agriculture customers.

28                  PG&E also anticipates that the construction of EV fast charging  
29                  stations and EV fleet charging stations, in as yet undetermined  
30                  locations, will create a need for system upgrades at those locations

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<sup>30</sup> Exhibit (PG&E-4), WP 17-20, lines 12, 57 and 63; and, WP 17-61 to WP 17-64 list of projects at WP 17-62, Project Description Table.

<sup>31</sup> Exhibit (PG&E-4), WP 17-16, lines 4-5.

1 within the next two to five years. This is based on input from  
2 EV charging station providers as well as discussions with internet  
3 delivery services intending to begin electrification of their vehicle  
4 fleet. One well-known EV network plans to increase annual stall  
5 installation from 600 stalls per year to 1,200 stalls per year by 2023.  
6 At 97 kilowatts (kW) per charger, this is a load increase of 58 MW  
7 per year.

8 Former Governor Brown's Executive Order B-48-18<sup>32</sup> set a  
9 goal of having 250,000 EV chargers installed by 2025. The  
10 January 2021 Electric Vehicle Charging Infrastructure Assessment  
11 for Assembly Bill (AB) 2127 finds that, at the present time, California  
12 has only 67,000 public and shared chargers installed, of which  
13 5,000 are DC fast chargers. The report anticipates that by 2030,  
14 968,000 chargers will be needed to support 5 million EVs.

15 As it did in the 2020 GRC, PG&E is including separate forecasts  
16 in MWC 46H for known New Business-related (NB-related) capacity  
17 projects and for "Unidentified, Emergent Work." Forecasting  
18 emergent work in this way allows the Capacity Program to reduce  
19 changes in its work plan and more efficiently plan projects from start  
20 to finish.

21 The Emergent Work funding for substation projects is forecast  
22 based upon the increasing rate of new applications for service that  
23 require capacity work to serve. Of the emergent funding for  
24 2023-2026, 79 percent has already been allocated to  
25 newly-identified emergent projects.<sup>33</sup> The Emergent Work funding  
26 forecast in MWC 46 is less in the near-term, and increases in later  
27 years, because more of the near-term work has already been  
28 specifically identified. This is because customers requesting new  
29 service for single, large-demand locations historically submit  
30 applications 1-3 years prior to their anticipated in-service date.

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<sup>32</sup> Executive Order B-48-18, adopted January 26, 2018.

<sup>33</sup> Exhibit (PG&E-4) WP 17-20, line 80, and WP 17-22, line 124.

1                   **4) Land Purchases and New Distribution Substations (MAT 46N)**

2                   The work in MAT 46N consists of constructing new substations  
3                   to increase capacity.

4                   PG&E's forecast for MAT 46N is close to \$0 for the entire  
5                   2021-2026 time period. PG&E's 2023 forecast of \$0 is \$0.05 million  
6                   less than 2020 recorded capital expenditures of \$0.05 million.<sup>34</sup>  
7                   The reason for the decrease is that PG&E is not forecasting any  
8                   new substation projects in 2023-2026.

9                   **5) Support for Transmission and Substation-Related Work**  
10                  **(MAT 46T)**

11                  PG&E's 2023 forecast for this area is \$0. Projects in MAT 46T  
12                  are specifically identified for the transmission- or substation-related  
13                  project they support. Currently, PG&E has not identified any  
14                  projects in MAT 46T and is not forecasting any expenditures in the  
15                  2021-2026 timeframe.

16                  **6) MWC 46 Distribution Substation Capacity Forecast Summary**

17                  Table 17-6 summarizes PG&E's forecasts and historical  
18                  expenditures for MWC 46.<sup>35</sup>

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<sup>34</sup> Exhibit (PG&E-4), WP 17-16, line 6.

<sup>35</sup> The substantial increase in the MWC 46A forecast in 2021 is due to the \$27.7 million projected cost of the Renz Energy Storage project at Llagas Substation.

TABLE 17-6  
MWC 46 RECORDED AND FORECAST EXPENDITURES BY MAT CODE  
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Description	MAT Code	2020 Recorded Adjusted	Forecast						Workpaper Reference
				2021	2022	2023	2024	2025	2026	
1	Normal Capacity Deficiencies	46A	\$6,359	\$34,848	\$28,888	\$15,743	\$8,332	\$5,645	\$801	WP 17-16, line 2
2	Emergency and Operational Capacity	46F	11,942	17,773	8,768	977	3,241	4,995	-	WP 17-16, line 3
3	NB-Related (Includes Emergent Work)	46H	17,226	26,230	27,534	41,363	56,488	61,345	73,927	WP 17-16, line 4
4	Land Purchases and New Distribution Substation	46N	46	-	-	-	-	-	-	WP 17-16, line 6
5	Miscellaneous	46#	695	-	-	-	-	-	-	WP 17-16, line 1
6	Total		\$36,270	\$78,880	\$65,191	\$58,082	\$68,061	\$71,985	\$74,728	

1           **b. Distribution Line Capacity (MWC 06)**

2           MWC 06 includes capacity expansion work outside of substations.  
3           Projects in MWC 06 address specific capacity deficiencies or overload  
4           conditions, as well as voltage conditions outside of Electric Rule 2  
5           criteria on distribution lines and equipment. PG&E performs this work to  
6           prevent equipment damage or failure due to excessive heating and to  
7           prevent outages.

8           PG&E's forecast for MWC 06 is \$233.7 million in 2021,  
9           \$150.5 million in 2022, \$137.7 million in 2023, \$163.2 million in 2024,  
10          176.3 million in 2025, and \$187.5 million in 2026. PG&E's 2023 forecast  
11          for this area is \$29.9 million more than 2020 recorded expenditures of  
12          \$107.3 million due to increasing levels of emergent capacity work,  
13          an expansion of the overloaded transformer replacement program, and  
14          higher project costs.<sup>36</sup>

15          PG&E separates MWC 06 work into the following MATs:

- 16          • Feeder Projects Associated with Substation Work (MAT 06A);
- 17          • Overloaded Line Transformers (MAT 06B);
- 18          • Circuit Reinforcement – Distribution Planning (DP) Managed  
19          (MAT 06D);
- 20          • Circuit Reinforcement – Project Services (PS) Managed (MAT 06E);
- 21          • Voltage Complaint Projects Involving Secondary Distribution  
22          (MAT 06G);
- 23          • NB-Related Capacity Increase (MAT 06H);
- 24          • Operational Capacity Projects (MAT 06I);
- 25          • Power Factor Management (MAT 06K);
- 26          • Enable Distributed Generation (DG) Distribution Line (MAT 06P);
- 27          and
- 28          • Line Voltage Regulator Revolving Stock (MAT 06#).

29          PG&E coordinates projects in these categories, to the extent  
30          possible, with substation work under MWC 46 to jointly address specific  
31          overloads or capacity deficiencies.

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<sup>36</sup> Exhibit (PG&E-4), WP 17-15, line 14.

1 A summary of the forecast expenditures for all distribution line  
2 capacity work in MWC 06 is in Table 17-7 at the end of this section.  
3 PG&E describes below the major drivers for the forecast capital  
4 expenditures.

### 5 **1) Feeder Projects Associated with Substation Work (MAT 06A)**

6 The work in MAT 06A encompasses installing and/or replacing  
7 underground cable and overhead conductor associated with new  
8 substation transformers and feeders. The forecast is based on  
9 specifically identified projects for normal load growth type capacity  
10 work or other drivers. The workpapers supporting this chapter list  
11 the projects included in the forecast.<sup>37</sup>

12 PG&E's forecast for MAT 06A is \$39.8 million in 2021,  
13 \$23.3 million in 2022, \$10.1 million in 2023, \$10.6 million in 2024,  
14 11.6 million in 2025, and \$12.3 million in 2026.<sup>38</sup> PG&E's 2023  
15 forecast for MAT 06A is \$10.1 million, including escalation, which is  
16 \$3.7 million less than 2020 recorded capital expenditures of  
17 \$13.8 million.<sup>39</sup> The 2023 forecast is based on projects that were  
18 specifically identified at the time; the Emergent Work forecast in  
19 MWC 06H contains funding for additional, similar projects not  
20 specifically identified at the time of the forecast.

### 21 **2) Overloaded Line Transformers (MAT 06B)**

22 Line transformers convert primary voltages—4 kilovolts (kV) and  
23 above—to standard secondary customer service voltages, such as  
24 120/240 volts (V). Overloaded overhead and underground line  
25 transformer replacement work in MAT 06B corrects capacity  
26 deficiencies on distribution line transformers, either by replacing the  
27 overloaded line transformer with a larger transformer, or by adding  
28 an additional transformer and transferring load. PG&E identifies line  
29 transformer projects by overload reports using SmartMeter™ data.

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<sup>37</sup> Exhibit (PG&E-4), WP 17-17, lines 1-18; and, pages WP 17-19 to WP 17-20 of Table 17-18.

<sup>38</sup> Exhibit (PG&E-4), WP 17-15, line 1.

<sup>39</sup> *Id.*

1 PG&E is placing increased focus on replacing overloaded  
2 transformers due to its recognition that overloaded transformers can  
3 become potential ignition sources and can contribute to the effects  
4 of global climate change. In certain rare circumstances, overloaded  
5 transformers can fail and start ignitions with serious consequences,  
6 especially in High Fire Threat District (HFTD) areas. Global  
7 temperature rise has also increased the need for air conditioning in  
8 temperate PG&E communities that historically did not have  
9 significant air conditioning electrical demands.

10 Starting in April 2020, PG&E conducted a pilot in North Valley to  
11 evaluate costs and best practices to address overloaded  
12 transformers in HFTD areas. An Overloaded Transformer Action  
13 Plan was to address these evolving conditions on PG&E's system.

14 This GRC forecast now encompasses existing transformer  
15 replacement, but also includes replacements to address HFTD  
16 ignitions and climate vulnerability and is included as part of the  
17 Overloaded Transformer Action Plan. PG&E is forecasting an  
18 increase for this program from its 2020 recorded costs of  
19 \$0.9 million to \$5.0 million in 2021, \$4.7 million in 2022, \$8.2 million  
20 in 2023, \$10.7 million in 2024, \$11.3 million in 2025, and  
21 \$11.7 million in 2026.<sup>40</sup> This represents a replacement rate of  
22 150-200 transformers per year in 2021 and 2022 and 350-400 per  
23 year for 2023 through 2026.<sup>41</sup>

### 24 **3) Circuit Reinforcement—DP Managed (MAT 06D)**

25 The work in MAT 06D encompasses installing and/or replacing  
26 underground cables, overhead conductors, line switches, protective  
27 devices, and voltage regulating devices to meet voltage, operational  
28 and capacity needs. Work in this category is for smaller projects.

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<sup>40</sup> Exhibit (PG&E-4), WP 17-15, line 2; and, WP 17-28, line 24.

<sup>41</sup> PG&E also replaces overloaded transformers that have failed or present an imminent hazard as part of the Emergency Recovery Program (see Ch. 6 of this exhibit, Electric Emergency Recovery). Forecasts in that program are not duplicative of forecasts in the Capacity Program.

1 PG&E's forecast for MAT 06D is \$0.7 million in 2021,  
2 \$4.0 million in 2022, \$4.5 million in 2023, \$5.3 million in 2024,  
3 5.8 million in 2025, and \$6.1 million in 2026.<sup>42</sup> PG&E's 2023  
4 forecast is \$2.5 million higher than the 2020 recorded amount of  
5 \$2.0 million.<sup>43</sup> PG&E's recorded expenditures in 2018-2020 were  
6 low by historical standards; PG&E's 2023 forecast returns to  
7 historical trends.

#### 8 **4) Circuit Reinforcement–PS Managed (MAT 06E)**

9 Projects in MAT 06E involve the same type of work as  
10 MWC 06D, but generally have a larger scope and are managed by  
11 Project Services personnel, rather than by Distribution Planning.

12 PG&E's forecast for MAT 06E is \$27.5 million in 2021,  
13 \$17.0 million in 2022, \$24.0 million in 2023, \$29.6 million in 2024,  
14 32.2 million in 2025, and \$34.3 million in 2026. PG&E's 2023  
15 forecast for MAT 06E is \$3.9 million more than 2020 recorded  
16 capital expenditures of \$21.1 million.<sup>44</sup> PG&E's 2023 forecast is  
17 higher than 2020 costs due to a shift from 06D to 06E due to more  
18 PS Managed Work.

#### 19 **5) Voltage Complaint Projects Involving Secondary Distribution** 20 **(MAT 06G)**

21 Work in MAT 06G typically consists of adding or upgrading:  
22 (1) existing transformers; (2) secondary distribution conductors;  
23 and/or (3) secondary service wires. PG&E conducts this work to  
24 comply with the voltage requirements of Electric Rule 2. PG&E  
25 typically identifies this work from customer complaints. PG&E then  
26 sets a recording voltmeter at the service delivery point to confirm the  
27 problem. If a voltage problem is identified, PG&E personnel  
28 evaluate potential solutions and determine a cost-effective remedy.

29 PG&E's forecast for MAT 06G is \$2.9 million in 2021,  
30 \$3.0 million in 2022, \$2.8 million in 2023, \$3.3 million in 2024,

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42 Exhibit (PG&E-4), WP 17-15, line 3.

43 *Id.*

44 Exhibit (PG&E-4), WP 17-15, line 4.

1 3.5 million in 2025, and \$3.7 million in 2026. PG&E's 2023 forecast  
2 is \$0.6 million more than 2020 recorded capital expenditures of  
3 \$2.2 million.<sup>45</sup> PG&E's forecast is based roughly on a 3-year  
4 (2017-2019) historical average.

## 5 **6) NB-Related Capacity Work (MAT 06H)**

6 PG&E performs capacity reinforcement projects under MAT 06H  
7 to eliminate overloads, due to an individual new development or an  
8 existing customer's load increase. PG&E's local area planners  
9 forecast the need for these projects, based on current requests for  
10 service and building activity.

11 Over the last few years, a significant portion of PG&E's overall  
12 capacity growth has been from large load increases for individual  
13 customers, such as electric vehicle charging, internet delivery  
14 services, data centers, drought-related pumping loading, expansion  
15 of tech company facilities, and indoor agriculture customers. These  
16 types of specific individualized capacity projects lead to significant  
17 variations in the capacity driven work in a particular location from  
18 year-to-year and are difficult to forecast and plan far in advance.

19 Consistent with the forecast for MAT 46H, PG&E includes a  
20 forecast in MWC 06H for "Unidentified, Emergent Work."  
21 The Emergent Work funding for distribution line projects is forecast  
22 based upon 2020 spend with increasing year-over-year spending to  
23 account for the number of new business applications for service that  
24 require capacity work to serve these loads.

25 PG&E's forecast for MAT 06H is \$140.9 million in 2021,  
26 \$84.0 million in 2022, \$71.9 million in 2023, \$84.3 million in 2024,  
27 \$90.9 million in 2025, and \$96.9 million in 2026. PG&E's 2023  
28 forecast is \$20.9 million more than 2020 recorded capital  
29 expenditures of \$51.0 million.<sup>46</sup> The 2023 increase over historic  
30 spend is due to an increase in the number of new business

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<sup>45</sup> Exhibit (PG&E-4), WP 17-15, line 5.

<sup>46</sup> Exhibit (PG&E-4), WP 17-15, line 13.

1 applications for service that require capacity work to serve these  
2 loads.

3 **7) Operational Capacity Projects (MAT 06I)**

4 MAT 06I generally includes two distinct types of work:

- 5 (1) completing mainline loops or installing mainline back-ties; and  
6 (2) operational capacity projects to reduce the number of customers  
7 or the load on certain heavily loaded circuits. Additionally, there are  
8 some projects in MAT 06I to install switches or reconductor existing  
9 distribution line to increase local operational capacity, based on  
10 input from field personnel or engineers who operate the system.

11 PG&E's forecast for MAT 06I is \$5.8 million in 2021, \$5.3 million  
12 in 2022, \$6.7 million in 2023, \$8.0 million in 2024, \$8.7 million in  
13 2025, and \$9.2 million in 2026. PG&E's 2023 forecast is  
14 \$2.2 million more than 2020 recorded capital expenditures of  
15 \$4.5 million.<sup>47</sup> PG&E's forecast is based roughly on a 3-year  
16 (2018-2020) historical average.

17 **a) Complete Mainline Loops to Comply with Design Standards**

18 PG&E's primary mainline system is designed so that, when  
19 completed, each mainline section is connected (with an  
20 adequately-sized conductor) to the mainline system at both  
21 ends. Both sources to a mainline section must be completed  
22 and energized as soon as the connected energized  
23 transformers served from any continuous section of that same  
24 main-line section total more than 1,500 kV-amperes  
25 (nameplate) or serve more than 100 customers. Completion of  
26 mainline loops provides two primary paths of service for  
27 reliability purposes. PG&E has identified 120 locations that do  
28 not meet these design criteria. PG&E's forecast for this work is  
29 \$2.0 million in 2021, \$2.8 million in 2022, \$2.8 million in 2023,  
30 \$2.8 million in 2024, \$2.8 million in 2025, and \$2.8 million in  
31 2026.<sup>48</sup>

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<sup>47</sup> Exhibit (PG&E-4), WP 17-15, line 9.

<sup>48</sup> Exhibit (PG&E-4), WP 17-29.

1                   **b) Reducing the Number of Customers Per Circuit to Fewer**  
2                   **Than 6,000 or Reducing the Load to 600 Amperes or Less**

3                   Feeders with 6,000 or more customers per circuit, or with a  
4                   load of more than 600 amps, pose two issues: (1) a large  
5                   number of customers are affected when an outage occurs, due  
6                   to a circuit breaker opening; and (2) typical loading limits on  
7                   adjacent circuits could hinder the ability to reconfigure  
8                   highly-loaded circuits. These issues negatively affect service  
9                   reliability in both customer outage frequency and duration.

10                  For the 2023 GRC cycle, PG&E has identified  
11                  11 distribution line only projects (no associated substation work)  
12                  to reduce the number of customers per circuit to less than  
13                  6,000<sup>49</sup> at a cost of \$1.6 million per year from 2023-2026, and  
14                  two distribution line only projects<sup>50</sup> to reduce loading to  
15                  600 amps or less at a cost of \$0.6 million per year from  
16                  2023-2026.

17                  Additional forecasted spend in 06I comes from mainline tie  
18                  projects. These projects typically allow for improved ability to  
19                  reconfigure circuits in emergencies and for planned clearances.  
20                  These projects are specifically identified by operational or  
21                  planning engineers and then funded from emergent operational  
22                  capacity funds.

23                  **8) Power Factor Management (MAT 06K)**

24                  The 2023 forecast for MAT 06K will allow PG&E to continue  
25                  installing System Control and Data Acquisition (SCADA) controls on  
26                  strategically located distribution capacitor banks. Remote capacitor  
27                  operability will allow control setting changes to be made remotely,  
28                  ensuring greater operational flexibility for better power factor  
29                  management, as well as increased voltage and reactive power  
30                  support of the system.

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<sup>49</sup> Exhibit (PG&E-4), WP 17-30.

<sup>50</sup> Exhibit (PG&E-4), WP 17-31.

1 PG&E's forecast for MAT 06K is \$0 million in 2021, \$0.6 million  
2 in 2022, \$1.1 million in 2023, \$1.3 million in 2024, \$1.4 million in  
3 2025, and \$1.5 million in 2026.<sup>51</sup> PG&E's 2023 forecast is  
4 \$1.1 million more than 2020 recorded capital expenditures of  
5 \$0.04 million.<sup>52</sup>

6 In 2017-2021, spending in this program was re-allocated to  
7 other, higher priority capacity work such as customer-driven new  
8 business capacity. The 2022-2026 forecast assumes 0 units in  
9 2021, 20 units in 2022, 34 units in 2023, 40 units in 2024, 44 units in  
10 2025, and 46 units in 2026. This forecast assumes a cost of  
11 \$33,000 per capacitor bank to enable SCADA which is based on the  
12 updated cost to replace a capacitor unit with a unit that can  
13 accommodate a SCADA control.<sup>53</sup>

#### 14 **9) Enable Distributed Generation (DG) Distribution Line (MAT 06P)**

15 Work in MAT 06P includes distribution upgrades for DERs.  
16 The primary purpose of the program is to upgrade the distribution  
17 system to enable two-way power flow in order to facilitate  
18 interconnection by DER customers. Voltage regulating devices  
19 located in a mainline section with control settings that allow  
20 cogeneration operation when the mainline is temporarily  
21 reconfigured require the cogeneration setting to be disabled to  
22 ensure proper bi-directional operation. To facilitate the setting  
23 change, these regulators need remote control and access via  
24 SCADA. The forecast in MAT 06P is for funding to install SCADA  
25 on existing regulators that meet the criteria. PG&E has identified  
26 304 mainline regulators with recorded backflow of 10 amps or  
27 greater that have the potential for temporary reconfiguration  
28 requiring a control setting change prior to switching.

29 PG&E's 2023-2026 forecast for this area is approximately  
30 \$1.6 million annually. PG&E's 2023 forecast is \$0.4 million more

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<sup>51</sup> Exhibit (PG&E-4), WP 17-15, line 10.

<sup>52</sup> *Id.*

<sup>53</sup> Exhibit (PG&E-4), WP 17-25 and WP 17-32, line 18.

1 than 2020 recorded capital expenditures of \$0.9 million.<sup>54</sup>

2 The funding forecast is sufficient to install SCADA operability on  
3 0 units in 2021, 5 units in 2022, 9 units in 2023, 10 units in 2024,  
4 11 units in 2025, and 12 units in 2026. This forecast assumes a  
5 cost of \$150,000 per regulator bank to enable SCADA which is  
6 based on the updated cost to replace a regulator unit with a unit that  
7 can accommodate a SCADA control.<sup>55</sup>

#### 8 **10) Line Voltage Regulator Revolving Stock (MAT 06#)**

9 The purpose of the line voltage regulator revolving stock  
10 process is to centrally manage equipment stock to use as needed,  
11 and to minimize surplus stock. Some of the revolving stock consists  
12 of overhauled or repaired units that can be reused.

13 PG&E's forecast for purchase of line voltage regulators in  
14 MAT 06# is \$11.1 million in 2021, \$7.9 million in 2022, \$7.1 million  
15 in 2023, \$8.4 million in 2024, 9.2 million in 2025, and \$9.8 million in  
16 2026. PG&E's 2023 forecast for this area is \$7.1 million, including  
17 escalation, which is \$3.6 million less than 2020 recorded capital  
18 expenditures of \$10.7 million.<sup>56</sup> The 2020 recorded spend was  
19 abnormally high and reflects carryover from 2019 when only  
20 \$2.4 million was spent on voltage regulator purchases.

#### 21 **11) MWC 06 Distribution Line Capacity Forecast Summary**

22 Table 17-7 summarizes PG&E's forecasts and historical  
23 expenditures for Distribution Line Capacity in MWC 06.

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<sup>54</sup> Exhibit (PG&E-4), WP 17-15, line 11.

<sup>55</sup> Exhibit (PG&E-4), WP 17-26.

<sup>56</sup> Exhibit (PG&E-4), WP 17-15, line 12.

**TABLE 17-7  
MWC 06 RECORDED AND FORECAST EXPENDITURES BY MAT CODE  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	MAT Code	2020 Recorded Adjusted	Forecast							Workpaper Reference
				2021	2022	2023	2024	2025	2026		
1	Feeder Projects Associated With Substation Work	06A	\$13,832	\$39,787	\$23,260	\$10,066	\$10,610	\$11,591	\$12,347	WP 17-15, line 1	
2	Overloaded Transformers	06B	859	5,018	4,745	8,172	10,722	11,321	11,730	WP 17-15, line 2	
3	Circuit Reinforcement (DP) Managed	06D	2,010	654	3,952	4,481	5,316	5,770	6,147	WP 17-15, line 3	
4	Circuit Reinforcement (PS) Managed	06E	21,142	27,526	16,975	23,993	29,641	32,174	34,271	WP 17-15, line 4	
5	Voltage Complaints	06G	2,185	2,902	3,038	2,751	3,254	3,522	3,741	WP 17-15, line 5	
6	NB Related Capacity Work and Emergent Work	06H	51,049	140,910	84,001	71,873	84,271	90,924	96,876	WP 17-15, lines 6-8	
7	Operational Capacity Projects	06I	4,511	5,800	5,293	6,725	7,978	8,659	9,223	WP 17-15, line 9	
8	Power Factor Management	06K	43	-	618	1,119	1,326	1,440	1,535	WP 17-15, line 10	
9	Enable DG Distribution Line	06P	930	-	742	1,344	1,594	1,731	1,842	WP 17-15, line 11	
10	Line Voltage Regulator Revolving Stock	06#	10,706	11,124	7,852	7,131	8,460	9,181	9,780	WP 17-15, line 12	
11	Total		\$107,267	\$233,720	\$150,476	\$137,655	\$163,173	\$176,314	\$187,492		

1           **c. Estimating Method**

2                   PG&E used two methods to develop its capital expenditure  
3 forecasts for the traditional distribution capacity.

- 4           1) Specifically identified projects and identified emergent projects make  
5 up over 87 percent of the total MWC 46 2023-2026 capital forecast  
6 in the Capacity Program<sup>57</sup>. For these projects, PG&E relied on  
7 individual job forecasts using engineering estimates of the  
8 necessary work and unit cost data or costs from similar projects;  
9 and  
10          2) For smaller, re-occurring type of similar projects as well as emergent  
11 MWC 06 projects, PG&E based its forecast on a 3-year average of  
12 recorded expenditures, the increasing number of customer  
13 applications for service that require capacity work, and engineering  
14 judgment.

15   **D. Compliance With Section 5.2 of the 2020 GRC Settlement Agreement**  
16   **(“Deferred Work Principles”)**

17                   The 2020 GRC Settlement Agreement requires PG&E to include  
18 testimony in this GRC on deferred work if the following criteria are met:

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

26                   Work that was authorized in the 2020 GRC for MWCs in this chapter is  
27 needed to provide safe and reliable service, however there was no work that  
28 met the criteria for deferred work as described in the Settlement Agreement.  
29 This analysis is presented in the workpapers supporting Chapter 2 of this  
30 Exhibit.<sup>58</sup>

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<sup>57</sup> Exhibit (PG&E-4) WP 17-14, line 29; WP 17-20, Table 17-18, line 81; and, WP 17-22, Table 17-18, line 124.

<sup>58</sup> See Exhibit (PG&E-4), WP 2-13.

1 **E. Cost Tables**

2       The expense and capital forecasts for Electric Distribution Capacity related  
3 activities are summarized in the following tables:

- 4       • Table 17-8 shows 2016 through 2020 recorded expenses and 2021 through  
5       2023 forecast expenses; and
- 6       • Table 17-9 shows 2016 through 2020 recorded expenditures and 2021  
7       through 2026 forecast expenditures.

**TABLE 17-8  
EXPENSE  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast			Workpaper Reference
			2016	2017	2018	2019	2020	2021	2022	2023	
1	FZ	Electric Engineering and Planning	\$11,715	\$12,118	\$11,332	\$10,651	\$15,158	\$15,447	\$16,155	\$19,943	WP 17-1, line 1
2		Total	\$11,715	\$12,118	\$11,332	\$10,651	\$15,158	\$15,447	\$16,155	\$19,943	

**TABLE 17-9  
CAPITAL  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast					Workpaper Reference	
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		2026
1	06	E Dist Line Capacity	\$91,361	\$55,960	\$67,746	\$73,444	\$107,255	\$233,720	\$150,476	\$137,655	\$163,173	\$176,314	\$187,492	WP 17-6, line 1
2	46	E Dist Subst Capacity	42,862	17,354	12,376	17,900	36,270	78,880	65,191	58,082	68,061	71,985	74,728	WP 17-6, line 2
3		Total	\$134,223	\$73,314	\$80,122	\$91,344	\$143,525	\$312,600	\$215,667	\$195,738	\$231,234	\$248,299	\$262,219	

**PACIFIC GAS AND ELECTRIC COMPANY  
2023 GENERAL RATE CASE**

Testimony   X   Workpapers \_\_\_\_\_ SOQ \_\_\_\_\_

Exhibit Number:   4   Chapter Number:   17  

Chapter Title:   Electric Distribution Capacity, Engineering and Planning  

Witness Name:   Satvir Nagra  

Page No.	Line No.	Item	As Filed	As Corrected
<b>Errata as of November 5, 2021</b>				
17-17, Table 17-4	1	DOVHD-C09A Risk Drivers Addressed	D-Line Equipment Failure	Foundational
17-17, Table 17-4	2	DOVHD-C008 Risk Drivers Addressed	D-Line Equipment Failure and Other	D-Line Equipment Failure

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 18**  
**NEW BUSINESS AND WORK AT THE REQUEST OF OTHERS**  
**[INCLUDES NOVEMBER 5, 2021 ERRATA]**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 18  
NEW BUSINESS AND WORK AT THE REQUEST OF OTHERS

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2   **CHAPTER 18**  
3                                   **NEW BUSINESS AND WORK AT THE REQUEST OF OTHERS**

4   **A. Introduction**

5       **1. Scope and Purpose**

6                   The purpose of this chapter is to demonstrate that Pacific Gas and  
7                   Electric Company's (PG&E) forecasts of expense and capital expenditures  
8                   for its New Business and Work at the Request of Others (NB/WRO)  
9                   Program<sup>1</sup> are reasonable and should be approved. PG&E is required by its  
10                  approved electric and gas tariff and franchise agreements to perform the  
11                  work in this program.

12                The scope of the work performed in the NB/WRO Program consists of:

- 13                • New Business (NB) – Installing electric infrastructure required to  
14                connect new customers to PG&E's distribution system and  
15                accommodate increased load from existing customers. NB work  
16                includes installation of the electric infrastructure to support electric  
17                vehicles (EV) deployed in PG&E's service area by customers to support  
18                California's transportation electrification and clean energy policies,  
19                Assembly Bill (AB) 841, and PG&E's new Electric Rule 29 pursuant to  
20                AB 841.<sup>2</sup>
- 21                • Work at the Request of Others (WRO) – Relocating PG&E's existing  
22                electric facilities, including undergrounding of existing overhead electric  
23                facilities, at the request of customers and governmental agencies under

---

1   Except where expressly indicated, Exhibit (PG&E-4), Ch. 18 covers the electric recorded and forecast costs for the NB/WRO Program; the gas costs for the NB/WRO Program are covered in Exhibit (PG&E-3), Chapter 14.

2   Assem. Bill No. 841 (2019-2020 Reg. Sess.) was enacted by the Legislature and signed into law by the Governor in 2020. AB 841 requires that electric distribution infrastructure related to electric vehicles (i.e., trenching, concrete, electrical wires) on the utility side of the meter, previously funded by third party non-residential customers, and Electric Vehicle Charge Network (EVCN) Phase 2 To-the-Meter expenditures, previously recovered in separate applications, be forecast and recovered in General Rate Cases (GRC).

1 the provisions of PG&E's Electric Rule 20B (Rule 20B) and Electric  
2 Rule 20C (Rule 20C).<sup>3</sup>

3 Work in the NB/WRO Program includes customer contact, design and  
4 engineering, job cost estimation, contract preparation, construction,  
5 inspection of third-party work, and facility mapping. Even though new  
6 customers may select a party other than PG&E to design and/or construct  
7 portions of the work covered by the NB/WRO Program (such as a new  
8 customer connection), PG&E must still perform the cost estimate, third-party  
9 design check, inspection of third-party construction work, construction tie-in,  
10 contract preparation, billing, mapping, and reimbursement of third-party work  
11 in accordance with its electric tariff.

## 12 **2. Summary of Request**

### 13 **a. Expense**

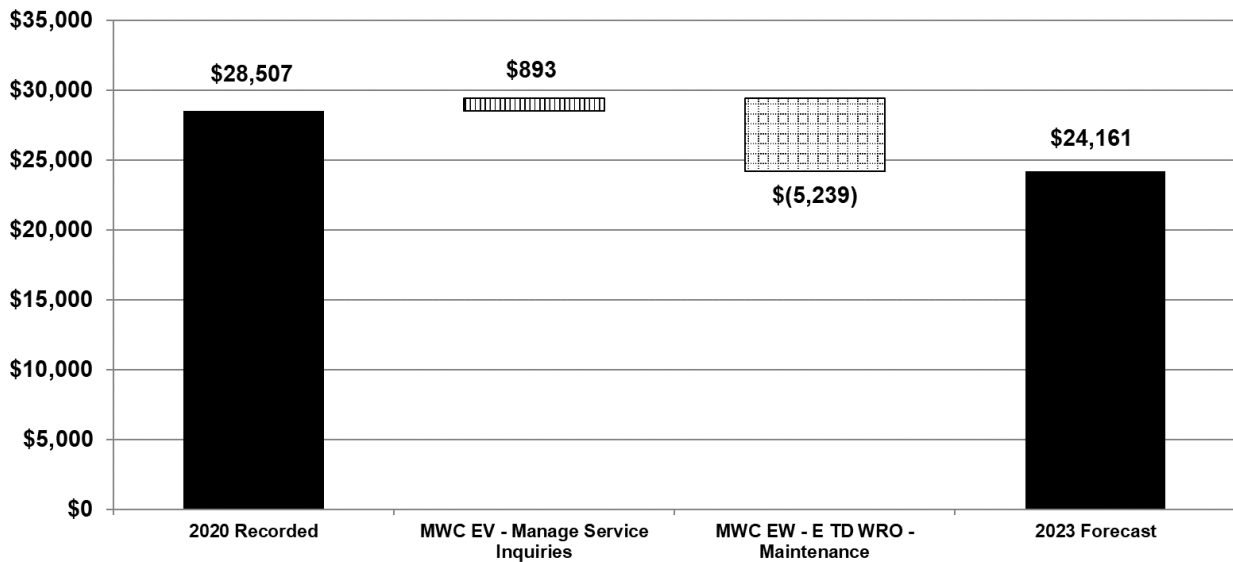
14 PG&E requests that the California Public Utilities Commission  
15 (CPUC or Commission) adopt its 2023 expense forecast for the  
16 NB/WRO Program of \$24.2 million, shown in Table 18-1. The costs for  
17 this program are tracked in Major Work Categories (MWC) EV and EW.  
18 As shown in Figure 18-1, PG&E's expense forecast for 2023 is  
19 \$4.3 million (or 15 percent) less than PG&E's 2020 recorded expenses.<sup>4</sup>  
20 This decrease is due to lower forecast costs for Expense Relocations  
21 and Electric Grid Interconnection as well as affordability initiatives.

---

<sup>3</sup> Undergrounding of existing overhead electric facilities under the provisions of PG&E's Electric Tariff Rule 20A is covered under Exhibit (PG&E-4), Ch. 19, Rule 20A. On May 11, 2017, the CPUC opened Order Instituting Rulemaking R.17-05-010 to Consider Revisions to Electric Rule 20 and Related Matters (Rule 20 OIR) to review and revise the Rule 20 Program statewide. On June 3, 2021, the Commission approved a final decision on Phase 1 of the Rule 20 OIR which, among other things, requires PG&E to create a balancing account for all its Rule 20 programs, including the Rule 20B and 20C programs. The Rule 20 OIR remains open and may require additional changes to Rule 20. PG&E will update its 2023 GRC content as needed to comply with the final decision on Phase 1 of the Rule 20 OIR and any subsequent decisions.

<sup>4</sup> See Exhibit (PG&E-4), WP 18-1, line 3.

**FIGURE 18-1  
NB/WRO PROGRAM  
EXPENSE WALK BY MWC 2020-2023  
(THOUSANDS OF NOMINAL DOLLARS)**



**TABLE 18-1  
NB/WRO PROGRAM EXPENSE  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	Workpaper (WP) Reference
1	EV-NB Service Inquiry	\$12,986	\$10,879	\$10,894	\$13,878	WP 18-1, line 1
2	EW- WRO	15,521	8,106	8,118	10,283	WP 18-1, line 2
3	Total Expense	\$28,507	\$18,985	\$19,013	\$24,161	

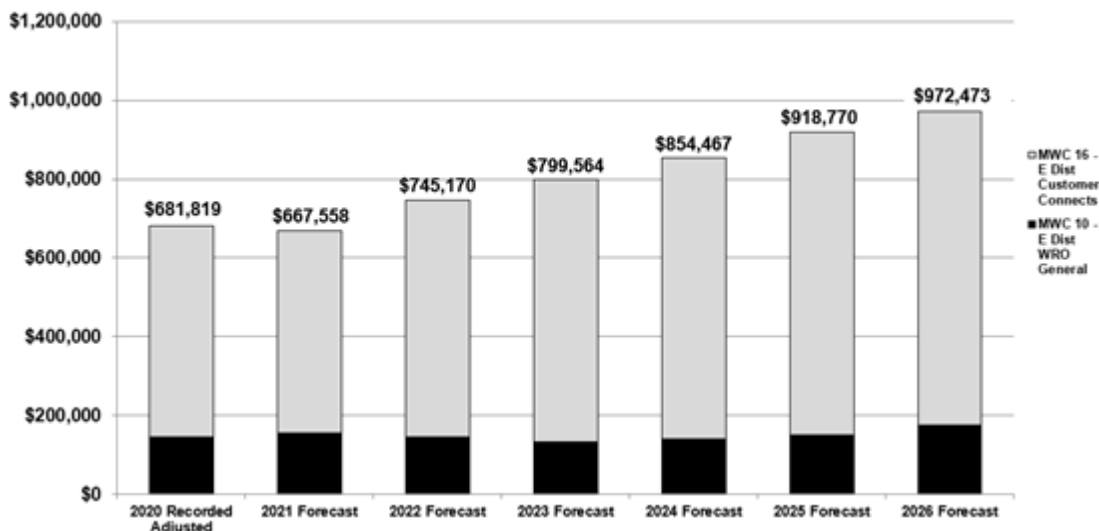
1           **b. Capital**

2           PG&E also requests that the Commission adopt its capital  
3           expenditure forecasts for the NB/WRO Program of \$667.6 million for  
4           2021, \$745.2 million for 2022, \$799.6 million for 2023, \$854.5 million for  
5           2024, \$918.8 million for 2025, and \$972.5 million for 2026, as shown in  
6           Table 18-2. The costs for this program are tracked in MWCs 16 (NB)  
7           and 10 (WRO). As shown in Figure 18-2, PG&E's 2023 capital  
8           expenditure forecast for externally driven work is \$117.7 million  
9           (17 percent) more than the capital expenditures recorded in 2020.<sup>5</sup> The

<sup>5</sup> See Exhibit (PG&E-4), WP 18-17, line 3.

1 increase is driven primarily by a projected increase in demand for new  
 2 residential customer connections and the inclusion in the GRC forecast  
 3 of some EV charging infrastructure costs that were historically covered  
 4 by customers or recovered in other proceedings.

**FIGURE 18-2  
 NB/WRO PROGRAM  
 CAPITAL EXPENDITURES 2020-2026  
 (THOUSANDS OF NOMINAL DOLLARS)**



**TABLE 18-2  
 NB/WRO PROGRAM  
 CAPITAL FORECAST BY MWC 2020-2026  
 (THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	16 – Electric NB	\$536,190	\$511,868	\$600,122	\$666,795	\$714,625	\$767,943	\$796,132	WP 18-17, line 2
2	10 – Electric WRO	145,630	155,690	145,048	132,769	139,842	150,827	176,341	WP 18-17, line 1
3	Total	\$681,819	\$667,558	\$745,170	\$799,564	\$854,467	\$918,770	\$972,473	

### 5 **3. Overview of Recorded and Forecast Costs**

6 The NB/WRO program consists of two expense MWCs—MWC EV  
 7 (Electric NB Service Inquiry) and MWC EW (Expense WRO)—and  
 8 two capital MWCs—MWC 16 (Electric NB) and MWC 10 (Electric WRO).  
 9 Each of these MWCs will be discussed below.

1           **a. Expense**2                   **1) MWC EV – NB Service Inquiry**

3                   MWC EV includes work associated with processing customer  
4                   applications for new gas and electric services<sup>6</sup> and coordinating  
5                   requests from existing customers for additional load and  
6                   re-arrangements on existing services.<sup>7</sup> PG&E tracks costs in  
7                   MWC EV by using two Maintenance Activity Types (MAT), and  
8                   three forecasting categories which are summarized in Table 18-3  
9                   and explained in further detail below.

**TABLE 18-3  
MWC EV FORECAST CATEGORIES AND MAT DESCRIPTIONS**

Line No.	Description	MAT	Forecast Category
1	New Customer Service Inquiry	EVA	EVA – Service Inquiry
2	OK to Serve – Added Load Coordination Routine	EVB	OK to Serve – Routine
3	OK to Serve – Added Load Coordination Plug in Electric Vehicles (PEV)	EVB	OK to Serve – PEV

10                   For 2023, MWC EV expenditures are forecast to increase by  
11                   \$0.9 million (7 percent) over recorded expenditures in 2020.<sup>8</sup> This  
12                   change is mainly driven by an increase in projected electric  
13                   customers and an increase in Plug-in Electric Vehicle (PEV)  
14                   applications related to AB 841. The change in expenditures by  
15                   forecasting category is summarized in Figure 18-3

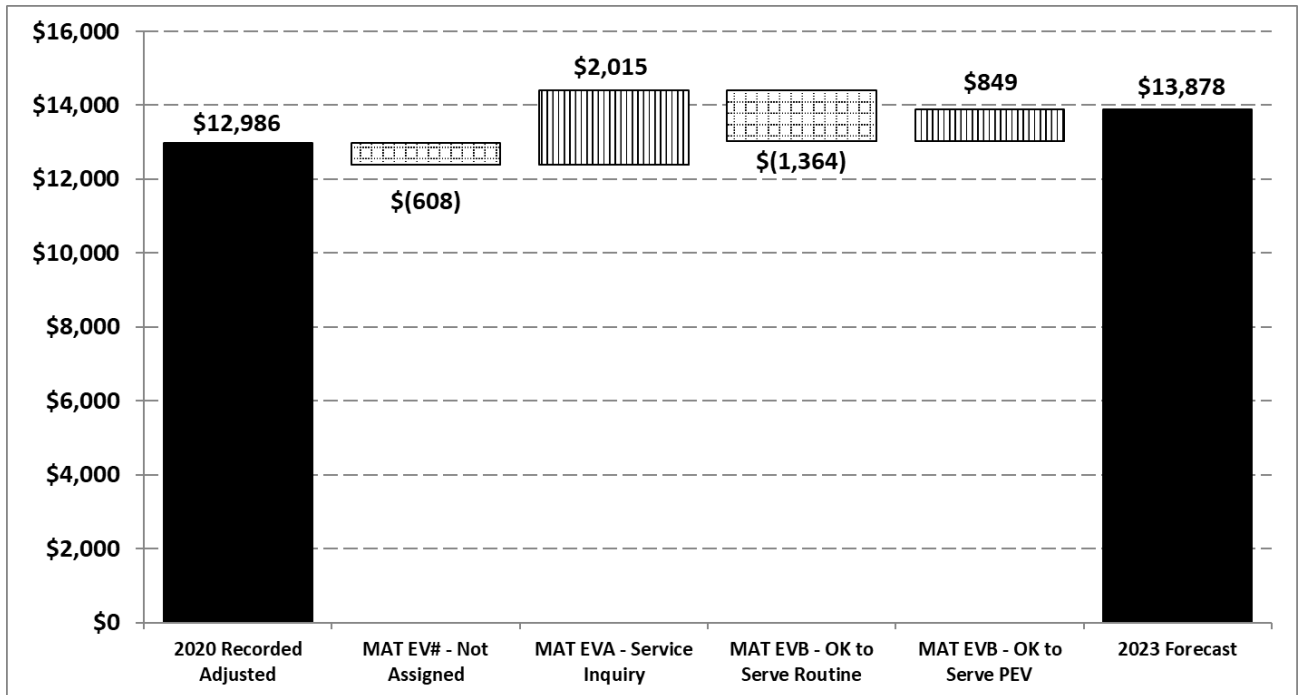
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<sup>6</sup> MWC EV supports both gas and electric service-related inquiries. Both gas and electric recorded and forecast expenditures for MWC EV are covered in this chapter; 55 percent of these expenditures are allocated to electric and 45 percent to gas based on the ratio of PGE's total electric customers to total gas customers.

<sup>7</sup> The NB Program supports service upgrades to facilities serving existing individual customers. Upgrades to PG&E facilities that serve multiple customers are considered upgrades to the distribution system and are normally handled by the Capacity program. See Exhibit (PG&E-4), Ch. 17.

<sup>8</sup> See Exhibit (PG&E-4), WP 18-1, line 1.

**FIGURE 18-3  
NB/WRO PROGRAM  
EXPENSE WALK MWC EV 2020-2023  
(THOUSANDS OF NOMINAL DOLLARS)**



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**a) MAT EVA – NB Service Inquiry**

PG&E provides customer assistance to every applicant who requests a new connection. MAT EVA – NB Service Inquiry includes all expenditures related to PG&E’s Contact Center operations, which receives and processes NB applications.

**b) MAT EVB – OK to Serve – Routine**

MAT EVB tracks PG&E’s expenses for reviewing customer inquiries with respect to existing services. PG&E analyzes facilities that may be affected by proposed load increases or customer facility changes to prevent overloading, which can affect PG&E’s ability to provide safe and reliable service to the customer and others in the vicinity of the change. Load checks can also find pre-existing overload conditions, which are then corrected to prevent issues arising from further load additions or facility changes. This load analysis work is charged to MAT EVB – OK to Serve whether or not further construction

1 work is needed. If construction work is required, the  
2 construction work is charged to the appropriate capital or  
3 expense work category.

4 **c) MAT EVB – OK to Serve – PEVs**

5 Starting in late 2011, PG&E began receiving large volumes  
6 of added load service requests involving the purchase of PEVs.  
7 In response, PG&E began to separately track and forecast load  
8 checks specifically related to PEV purchases. Depending upon  
9 the charging selection made by the consumer (typically a  
10 120-volt, 240-volt, or fast charge option), the additional load to a  
11 single service, or local distribution system, can be substantial.  
12 The volume of load service requests is forecasted to increase in  
13 large part due to AB841.

14 **2) MWC EW – Expense WRO**

15 MWC EW covers the electric WRO expense work required by  
16 tariffs and franchise agreements. This work includes non-plant  
17 relocations and alterations of electric facilities (such as raising  
18 covers and frames for a street repaving project), as well as  
19 third-party Electric Grid Interconnection (EGI) activities. PG&E  
20 tracks costs in MWC EW by using eight MAT work types, which are  
21 grouped into three forecasting categories as summarized in  
22 Table 18-4, Figure 18-4, and explained in further detail below.

**TABLE 18-4  
MWC EW FORECAST CATEGORIES AND MAT DESCRIPTIONS**

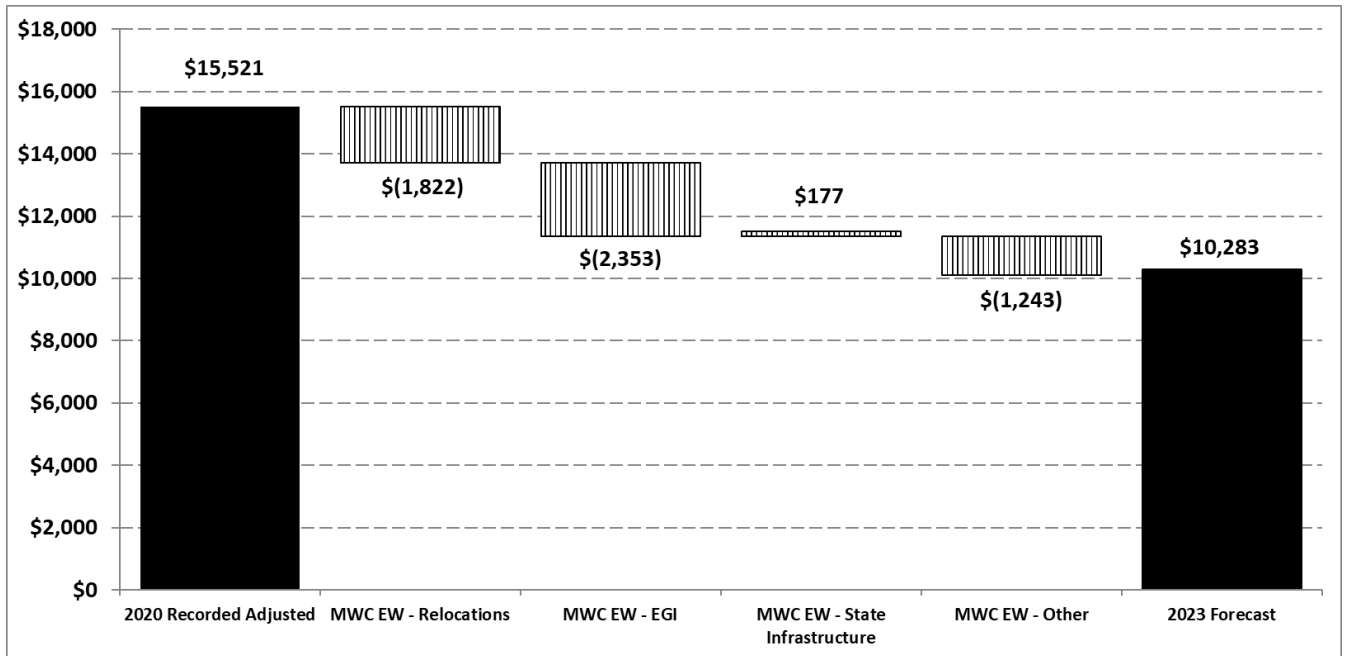
Line No.	Description	MAT
1	<b><u>Relocation</u></b>	
2	Division WRO Inquiries	EW0
3	Electric Service Alterations – Overhead	EW1
4	Electric Service Alterations – Underground	EW2
5	Temporary Electric Services	EW3
6	Adjust Box Lids and Covers	EW4
7	Land Service Inquires	EWP
8	Electric Support and Work Around (SAWA) – SF	EWS
9	Third-Party Electric Alterations (Paid on Actuals)	EWT
10	<b><u>Electric Grid Interconnect</u></b>	
11	Generation Interconnection Service	–
12	Pre-Parallel Inspections	–
13	<b><u>State Infrastructure</u></b>	
14	VTA – BART to Silicon Valley Phase II	–
15	CalTrain	–
16	Google (Diridon Redevelopment)	–
17	High Speed Rail	–
18	Water Fix	–

1                                For 2023, MWC EW expenditures are forecast to decrease by  
2                                \$5.2 million (or 34 percent) relative to recorded expenditures in  
3                                2020.<sup>9</sup> This change is driven by a \$2.4 million reduction in  
4                                EGI-related costs (application costs are expected to be offset by  
5                                application credits) and a reduction in forecast expense relocations  
6                                related to WRO capital work.

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<sup>9</sup> See Exhibit (PG&E-4), WP 18-1, line 2.

**FIGURE 18-4  
NB/WRO PROGRAM  
EXPENSE WALK MWC EW 2020-2023  
(THOUSANDS OF NOMINAL DOLLARS)**



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**a) MWC EW – Relocations**

The MWC EW Relocations forecast covers MATs that relate to a wide variety of work including: non-plant-related relocations of electric facilities, temporary electric services provided to customers during construction projects, and Land Department right-of-way record research requested by third parties that cannot be charged to a specific project.

**b) MWC EW – Electric Grid Interconnection**

PG&E’s EGI Department manages the electric interconnection process for all generation projects interconnected at PG&E’s distribution service. EGI projects may include retail tariff programs, compliance with Electric Rule 21, and interconnection applications for Federal Energy Regulatory Commission (FERC)-jurisdictional projects under the

1 Wholesale Distribution Tariff seeking Power Purchase  
2 Agreements (PPA).<sup>10</sup>

3 **b. Capital**

4 **1) MWC 16 – Electric NB**

5 As discussed in Section A.1, Electric NB consists of installing  
6 the electric infrastructure required to connect new customers to  
7 PG&E’s distribution system or to accommodate increased load from  
8 existing customers. The total cost of installing new electric  
9 infrastructure is shared between PG&E and the customer requesting  
10 the service. The cost sharing is detailed in Electric Rules 2, 15, 16  
11 and 29. PG&E’s forecasts are net of customer contributions. PG&E  
12 forecasts MWC 16 work in five forecasting categories – Residential  
13 Connects, Non-Residential Connects, PEV Expenditures,  
14 Distribution Transformer Purchases, and Distribution Transformer  
15 Scrapping – which are summarized in Table 18-5 and explained in  
16 further detail below.

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<sup>10</sup> PPAs include offerings such as the Renewable Market Adjusting Tariff Feed-in Tariff established under D.12-05-035 and D.13-05-034 to implement Sen. Bill No. 32 (2015-2016 Reg. Sess.).

**TABLE 18-5  
MWC 16 FORECAST CATEGORIES AND MAT DESCRIPTIONS**

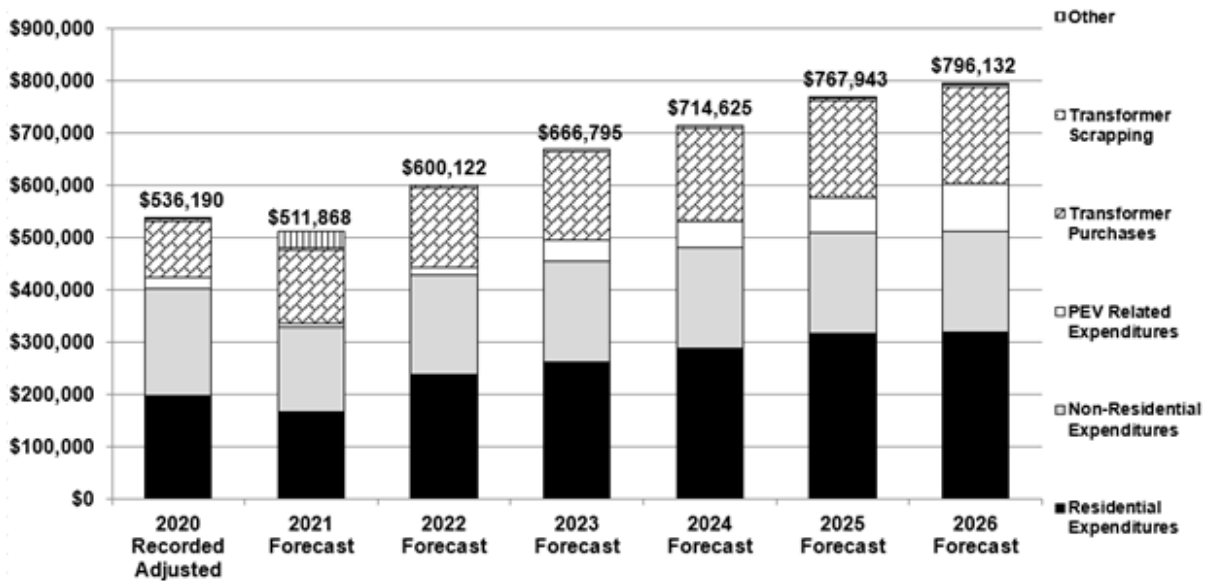
Line No.	Forecast Category Description	MAT
1	<b><u>Residential Connects</u></b>	
2	Residential – Subdivision Backbone	16R
3	Residential – Subdivision Service	16S
4	Residential – Other:	
5	NB-E-Res Mobile Home Dev	16A
6	Residential Extensions – Overhead	16B
7	Residential Services – Overhead	16C
8	Residential Services – Underground	16D
9	Streetlights	16O
10	Residential Extensions – Underground	16P
11	Residential Extensions and Services – Apartment Complexes	16Q
12	Residential Simple OH Services	16Y
13	NB-E-Res OH Svc R18-EP	166
14	NB-E-Res UG Svc R18-EP	167
15	<b><u>Non-Residential Connects</u></b>	
16	Commercial Extensions and Services – Overhead	16G
17	Commercial Extensions and Services – Underground	16H
18	Agricultural Extensions and Services – Overhead	16J
19	Agricultural Extensions and Services – Underground	16K
20	Irrigation/CATV Power Supply Services	16T
21	TELCO (Telephone/Communication) Services – Underground	16W
22	TELCO (Telephone/Communication) Services – Overhead	16X
23	NB System Improvements	16Z
24	<b><u>PEV Expenditures</u></b>	
25	Residential PEV – No Existing Overload	161
26	Residential PEV – Existing Overload	162
27	Non-Residential PEV - No Existing Overload	163
28	Non-Residential PEV - Existing Overload	164
29	Elec Veh_NB-E-CI Self-Standing	165
30	<b><u>Distribution Transformer Purchases</u></b>	160
31		
32	<b><u>Distribution Transformer Scrapping</u></b>	–

1                               For 2023, MWC 16 expenditures are forecast to increase by  
2                               \$130 million (or 24 percent) over PG&E’s 2020 recorded  
3                               expenditures.<sup>11</sup> This change is mainly driven by forecasted  
4                               increased demand for residential customer connections and service  
5                               upgrade and infrastructure work related to increased load from  
6                               PEVs. The change in expenditures by forecasting category is  
7                               summarized in Figure 18-5.

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<sup>11</sup> See Exhibit (PG&E-4), WP 18-17, line 2.

**FIGURE 18-5  
NB/WRO PROGRAM  
CAPITAL FORECAST MWC 16 2020-2026  
(THOUSANDS OF NOMINAL DOLLARS)**



1                    **a) MWC 16 – Residential Connects**

2                    This forecasting category captures the costs of building new  
3                    underground and overhead primary electric distribution systems,  
4                    the associated secondary systems, and services to residential  
5                    customers. This category is further broken down into  
6                    three sub-categories.

7                    1) Residential Connects – Subdivision Backbone

8                                       Subdivision Backbone refers to the electric  
9                    infrastructure installed along the street frontages in new  
10                    residential developments, as distinguished from the service  
11                    runs from the street to individual homes. Backbone  
12                    installation is the largest cost driver in residential  
13                    development work.

14                    2) Residential Connects – Subdivision Services

15                                       Residential Connects – Subdivision Services refers to  
16                    the completion of the electric service from the residential  
17                    backbone portion of the line extension to individual homes.

18                    3) Residential Connects – Other

1                   The Residential Connects – Other category includes all  
2                   other residential line extension and service work not  
3                   included in the two categories above. This includes all work  
4                   not related to new services to a subdivision, such as line  
5                   extensions and service installations to individual residential  
6                   customers, multi-family homes, and apartment buildings.

7                   **b) MWC 16 – Non-Residential Connects**

8                   This category captures the costs of building new  
9                   underground and overhead primary electric distribution  
10                  systems, and the associated secondary systems, and services  
11                  to non-residential customers. PG&E forecasts non-residential  
12                  work in the aggregate because work varies considerably  
13                  between MATs from year to year and there are no statistically  
14                  proven economic indicators upon which to base a more  
15                  granular forecast.

16                  **c) MWC 16 – PEV**

17                  This work category includes all distribution transformer,  
18                  secondary and service upgrade work to serve increased loads  
19                  related to PEVs. It includes electric distribution infrastructure  
20                  (i.e., trenching, concrete, electrical wires) on the utility side of  
21                  the meter, previously funded by third party non-residential  
22                  customers, and EVCN Phase 2 To-the-Meter expenditures,  
23                  previously recovered in separate applications. It also includes  
24                  upgrades for existing overload conditions identified through load  
25                  analysis. Upgrades to PG&E's high-voltage primary system, or  
26                  those resulting from voltage complaints, are funded as capacity  
27                  upgrades under MWC 06 (see Exhibit (PG&E-4), Chapter 17,  
28                  Electric Distribution Capacity).

29                  **d) MWC 16 – Transformer Purchases**

30                  PG&E purchases all the distribution transformers that are  
31                  installed as part of any capital project through the NB program.

1 Transformers are revolving stock<sup>12</sup> and the transformer forecast  
2 includes not only transformers installed in NB projects but also  
3 transformers used to replace transformers that fail in the field,  
4 transformers used in relocation work, and transformers used as  
5 part of conversion of overhead to underground facilities.

6 **e) MWC 16 – Transformer Scrapping**

7 Final scrapping, or retirement of distribution transformer  
8 units, is also captured in the NB Program.<sup>13</sup>

9 **2) MWC 10 – Electric WRO**

10 MWC 10 covers capital expenditures for relocating electric  
11 distribution and service facilities at the request of a government  
12 agency or other third party (e.g., private parties and developers),  
13 and for the conversion of overhead electric facilities to underground  
14 covered by Electric Rules 20B and 20C. These third-party requests  
15 often depend on funding available to governmental agencies for  
16 road widening or other infrastructure improvements, where franchise  
17 and master agreements provide the method of cost sharing between  
18 PG&E and the customer.

19 As with NB work, the cost of WRO work can be shared between  
20 PG&E and the customer requesting the work. The degree to which  
21 costs are shared for a given project is driven by the electric tariff  
22 (Electric Rules 15 and 16), franchise and master agreements, the  
23 party requesting the work, the location of the existing facilities, and  
24 the land rights applicable to those facilities. All calculations and  
25 forecasts presented here represent costs net of customer  
26 contributions or reimbursements.

27 PG&E's WRO capital expenditures forecast reflects its share of  
28 costs related to: (a) non-reimbursed; (b) partially reimbursed; and

---

**12** Revolving stock refers to a unit of plant that is capitalized upon purchase rather than installation. This is done to prevent multiple capitalizations of equipment that includes both newly purchased units and refurbished units.

**13** Any salvage value received from scrapped transformers settles to Accumulated Depreciation.

1 (c) fully reimbursed WRO projects.<sup>14</sup> The forecast for MWC 10 is  
 2 determined by using three forecasting categories that are dependent  
 3 upon the MAT code, reimbursement level, and size of the project.  
 4 Table 18-6 summarizes these forecasting categories, which are  
 5 explained in further detail below.

**TABLE 18-6**  
**MWC 10 FORECAST CATEGORIES AND MAT DESCRIPTIONS**

Line No.	Description	MAT	Forecast Category <sup>(a)</sup> by Reimbursement Level <sup>(b)</sup>		
			Full	Partial	Non
1	WRO-Rule 20B	10H	–	NB	–
2	WRO-Rule 20C	10I	–	NB	–
3	WRO-Overhead Relocation	10J	NB	Gov	Gov
4	WRO-Underground Relocation	10K	NB	Gov	Gov
5	WRO-Pole Only Relocation	10L	NB	Gov	Gov
6	WRO-Cust Req. Removal of Facilities	10M	NB	Gov	Gov
7	WRO-Cogeneration	10N	NB	Gov	Gov
8	WRO E OH CAP Proj>\$100,000	10O	NB	Gov	Gov
9	WRO E UG CAP Proj>\$100,000	10P	NB	Gov	Gov
10	Third Party WRO Paid on Actuals	10Q	NB	Gov	Gov
11	Major Projects	All	Maj	Maj	Maj
12	State Infrastructure	All	Maj	Maj	Maj

(a) Forecasting Categories:

- NB – NB-Related WRO
- Gov – Government-Related WRO
- Maj – Major Projects

(b) Reimbursement Levels:

- Full – Fully Reimbursed Project (full cost to third-party requestor)
- Partial – Partially Reimbursed Project (shared cost)
- Non – Non-Reimbursed Project (full cost to PG&E)

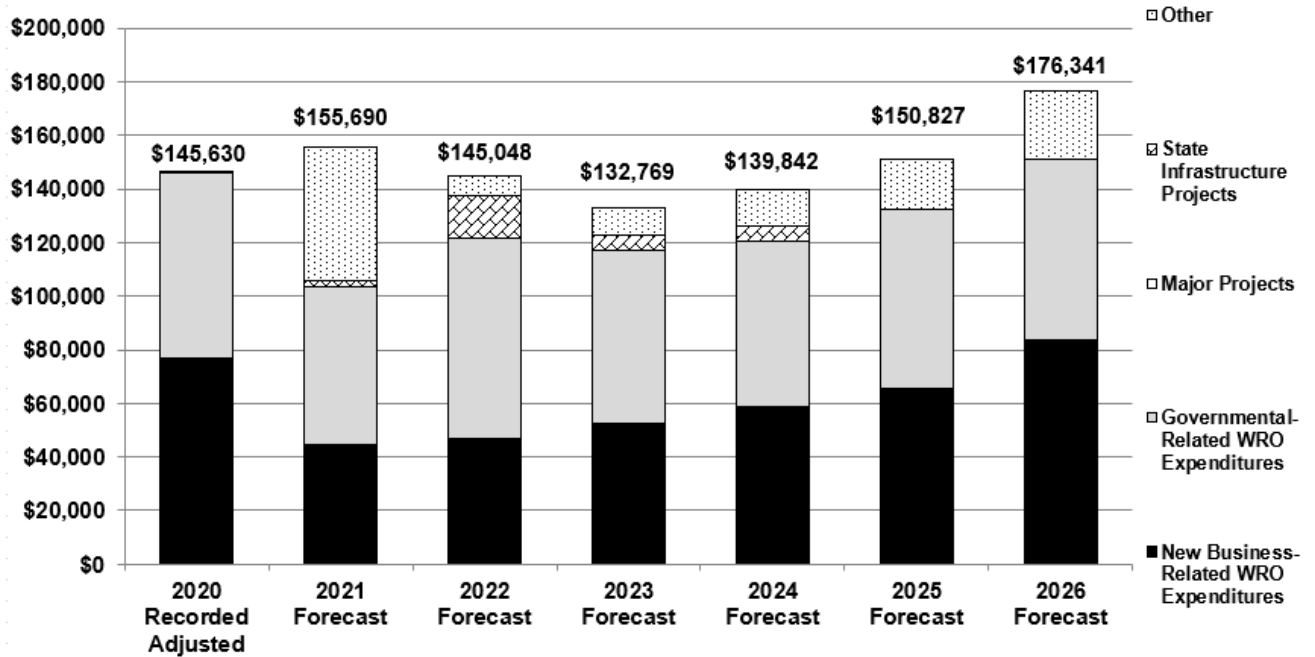
6 For 2023, MWC 10 expenditures are forecast to decrease by  
 7 \$12.9 million (or 9 percent) over recorded expenditures in 2020.<sup>15</sup>  
 8 This decrease is mainly driven by a reduction of NB-related WRO

<sup>14</sup> Even though a project may be defined as “fully-reimbursed,” it may incur net costs. Net costs can be caused by variances between the estimated and actual cost of a project (tariff-related WRO projects are billed to third parties at the estimated cost, with no true-up to the final actual cost). Additional net costs can be incurred if PG&E includes work in a project not billable to a customer.

<sup>15</sup> See Exhibit (PG&E-4), WP 18-17, line 1.

1 work as forecasted by the Rosen Consulting Group (RCG) model.  
2 The changes in expenditures by forecasting category between 2020  
3 and 2026 are summarized in Figure 18-6.

**FIGURE 18-6**  
**NB/WRO PROGRAM**  
**CAPITAL FORECAST MWC 10 2020-2026**  
**(THOUSANDS OF NOMINAL DOLLARS)**



4 **a) MWC 10 – NB Related WRO**

5 NB-related WRO includes all work under MATs 10H and 10I  
6 as well as fully reimbursable NB work in other MATs, as shown  
7 in Table 18-6.

8 MATs 10H and 10I correspond to electric overhead to  
9 underground facility conversions pursuant to Electric Rules 20B  
10 and 20C. Most work under Rules 20B and 20C is performed in  
11 conjunction with larger residential and non-residential  
12 development work in the NB Program. Cost responsibility for  
13 MAT 10H and 10I work is shared by PG&E and the customers  
14 requesting the work.

15 Fully reimbursed work in other MATs is also typically tied to  
16 NB development work. This would include any overhead or

1 underground relocations where PG&E's facilities are in an  
2 easement or right of way, and projects where PG&E facilities  
3 are located in city or county franchise areas but the third party  
4 requesting the work is not the governmental entity who is party  
5 to the franchise agreement.

6 **b) MWC 10 – Government-Related WRO**

7 Government-related WRO includes work performed at the  
8 request of a governmental entity (except undergrounding  
9 covered in MATs 10H and 10I). This work is either partially  
10 reimbursable or non-reimbursable. Non-reimbursed  
11 government related WRO projects normally cover work where  
12 PG&E's facilities are located in a franchise controlled by the  
13 requesting governmental entity.

14 **c) MWC 10 – Major Projects**

15 In addition to the NB and government-related WRO  
16 forecast, expenditures for large projects unrelated to Caltrans  
17 work historically have been forecast and recorded in MWC 10 –  
18 Major Projects. PG&E recorded only \$0.3 million of Major  
19 Projects expenditures in 2020 and is not forecasting any  
20 expenditures on these types of projects between 2021 and  
21 2026.

22 **d) MWC 10 – State Infrastructure Projects**

23 The State Infrastructure Projects portfolio has large-scale  
24 projects with schedules and scope dictated by third parties,  
25 typically state and local governments. The portfolio request for  
26 MWC 10 includes forecasted costs for relocation of electric  
27 distribution assets for three projects: California High-Speed  
28 Rail, Google, and VTA BART. These projects are discussed in  
29 greater detail in Section C.2.b.4, below.

30 **4. Support for Request**

31 Work in the NB/WRO Program is performed at the request of PG&E's  
32 customers or governmental agencies. PG&E is required to perform this  
33 work under its obligation to serve, its tariffs, and its franchise agreements

1 with local governments. PG&E's forecast methodology utilizes leading  
2 economic indicators for its service territory. See Section C – Activities and  
3 Costs, and Forecast Drivers by MWC.

#### 4 **5. Organization of the Remainder of This Chapter**

5 The remainder of this chapter is organized as follows:

- 6 • Section B – Program and Risk Overview
- 7 • Section C – Activities and Costs, and Forecast Drivers by MWC
- 8 • Section D – Compliance with Prior Commission Decisions
- 9 • Section E – Cost Tables

### 10 **B. Program and Risk Overview**

#### 11 **1. Program Description**

##### 12 **a. Program Overview**

13 The Program Management group budgets, tracks costs for, and  
14 forecasts NB/WRO expenditures. In addition, the Program Management  
15 group manages the NB/WRO Program by:

- 16 • Allocating budgets on an annual basis to PG&E's 19 divisions to  
17 perform NB/WRO work.
- 18 • Monitoring the volume of work by forecasting category using MAT  
19 codes in PG&E's SAP system to analyze trends and changes in  
20 NB/WRO work distribution.
- 21 • Tracking unit cost performance by forecasting category using MAT  
22 codes for NB/WRO capital and expense categories.
- 23 • Identifying and communicating best practices from individual  
24 divisions and other programs to enhance efficiency system wide and  
25 to improve customer satisfaction.

##### 26 **b. Management Structure**

27 PG&E manages its NB Program through the Work Planning,  
28 Program Management and Performance organization located within the  
29 Electric Distribution Operations line of business (LOB); PG&E manages  
30 its WRO Program through the Electric Core Programs organization  
31 located within the Major Projects and Programs LOB. While the  
32 NB/WRO Program Managers provide direct program support for  
33 NB/WRO activities, they also work closely with the Service Planning and

1 Design organization (within Distribution Operations) that provides  
2 design, estimating and technical support functions for all distribution  
3 programs within Gas and Electric Operations. Service Planning and  
4 Design has a strong customer focus that drives performance of many of  
5 the metrics, initiatives, and strategies discussed in the next sections.  
6 The NB Program also works closely with the Clean Energy  
7 Transportation department to evaluate, forecast and support  
8 PEV-related NB upgrades and planning.

### 9 **c. Key Metrics and Other Performance Measures**

10 PG&E uses a customer survey as a key indicator to measure  
11 performance and customer satisfaction. A Project Satisfaction Survey is  
12 sent out at three key stages for all NB Projects. The three stages of the  
13 project that triggers the deployment of a survey are Application  
14 Submittal Phase, Design Completion Phase, and Construction  
15 Completion Phase. All survey questions center around communication,  
16 timely scheduling and execution of the project, and quality of service.  
17 All Project Satisfaction Survey results are measured on a monthly and  
18 year over year basis and serve as the driver for key initiatives and  
19 process improvement efforts based on the results.

## 20 **2. Risk Integration**

21 Risk controls and mitigations are aligned to various MWCs and MATs in  
22 Electric Distribution. None of the MWCs presented in this chapter  
23 correspond to a risk mitigation or risk control that address a risk on Electric  
24 Operations' Corporate Risk Register. More information about risk  
25 mitigations and controls is in PG&E's Electric Distribution Risk Management  
26 testimony (Exhibit (PG&E-4), Chapter 3).

## 27 **C. Activities, Costs, and Forecast Drivers by MWC**

### 28 **1. Expense**

#### 29 **a. MWC EV – NB Services Inquiry**

##### 30 **1) MWC EVA – NB Service Inquiry**

31 NB service inquiry expenditures (MAT EVA) are driven by the  
32 total number of customer service applications and are not

1 significantly impacted by the type of application (residential or  
 2 non-residential). The average ratio of connects to applications  
 3 remains fairly constant from year-to-year; therefore, the  
 4 forecast percent change in total connects (contained in the capital  
 5 NB forecast) is a good gauge of the expected change in total service  
 6 applications received. PG&E's total forecast for service applications  
 7 is calculated using the total forecast for gas and electric connects  
 8 divided by the average ratio of connects to applications over the  
 9 past three years, including the addition of PEV-related connects now  
 10 required by AB 841 to be included in the GRC instead of in separate  
 11 applications.<sup>16</sup>

12 The forecast for MAT EVA, based on the methodology  
 13 described above, is shown in Table 18-7.

**TABLE 18-7**  
**MWC EV/MAT EVA – NB SERVICE INQUIRY FORECAST**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	MAT EVA – Service Inquiry Expenditure/Forecast	\$2,975	\$3,811	\$3,435	\$4,990	WP 18-6, line 1

14 The main driver of the 2023 forecast increase is a higher  
 15 volume of applications and cost escalation.<sup>17</sup>

## 16 **2) MAT EVB – OK to Serve Routine**

17 MAT EVB – OK to Serve Routine is driven by existing  
 18 customers either adding load or upgrading their service facilities  
 19 (e.g., an electric service panel), where that work does not result in  
 20 any capital work by PG&E, or work that can be billed to a customer  
 21 under PG&E's tariffs. The forecast for MAT EVB – OK to Serve  
 22 Routine is indexed to the average annual percent change in PG&E's  
 23 electric customer base.<sup>18</sup> The small increase shown in the table

<sup>16</sup> See Exhibit (PG&E-4), WP 18-7, line 6.

<sup>17</sup> See Exhibit (PG&E-4), WP 18-7, line 10.

<sup>18</sup> See Exhibit (PG&E-4), WP 18-8, line 2.

1 below is driven by a combination of an expected increase in the  
2 number of electric customers and escalation.

3 Table 18-8 summarizes the MAT EVB expense forecast for  
4 routine requests.

**TABLE 18-8**  
**MWC EV/MAT EVB – OK TO SERVE ROUTINE**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	EVb OK to Serve – Routine Expenditure/Forecast	\$9,363	\$6,871	\$6,733	\$7,999	WP 18-6, line 2

5 Affordability initiatives are forecasted to reduce costs by  
6 \$1.4 million (or 14 percent) in the 2023 forecast when compared to  
7 PG&E's 2020 recorded expenses.<sup>19</sup>

### 3) MAT EVB – OK to Serve PEV

8 In addition to the routine MAT EVB OK to Serve Routine work  
9 described above, PG&E forecasts an increase in customer load  
10 check activities driven by customer PEV purchases. For the  
11 purposes of this forecast, PG&E used a projection of expected PEV  
12 sales in PG&E's service territory provided by PG&E's Clean Energy  
13 Transportation Department.<sup>20</sup> This PEV sales volume is then  
14 adjusted by the percentage of customers expected to be placed on  
15 PG&E's residential or non-residential EV service rate schedules<sup>21</sup>  
16 to estimate the number of customers likely to contact PG&E after  
17 purchasing a PEV. The forecast's higher demand for  
18 non-residential EV customers load analysis is driven by AB 841  
19

<sup>19</sup> See Exhibit (PG&E-4), WP 18-8, line 6.

<sup>20</sup> After the MAT EVB forecast was finalized, PG&E concluded that it would be more appropriate to base its assumptions about PEV deployment on internal modelling and data which has been shared with the Commission. PG&E will file errata updating the assumptions and recalculating its forecast as necessary.

<sup>21</sup> Electric Schedule E-9: Experimental Residential Time-of-Use Service for Low Emission Vehicle Customers.

1 PEV-related expenditures under MAT EVB summarized in  
2 Table 18-9.

**TABLE 18-9**  
**MWC EV/MAT EVB – OK TO SERVE PEV**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	EVB OK to Serve PEV Expenditure/Forecast	\$40	\$1,405	\$726	\$889	WP 18-6, line 3

3 The primary driver for the increase in the forecast is the  
4 projected growth in the number of PEVs in PG&E's service territory.  
5 PEV ownership and deployment is expected to grow based on State  
6 transportation electrification and clean energy goals and mandates  
7 on sales targets, including Governor Newsom's executive order  
8 requiring the phase-out of non-EV vehicle sales by 2035.<sup>22</sup> This will  
9 result in an increase of owners using an EV rate, and a  
10 corresponding increase in EVB OK to Serve PEV spend overall.

#### 11 **4) MWC EV – NB Service Inquiry Forecast Summary**

12 Table 18-10 shows a summary of the forecast for MWC EV as a  
13 sum of major components of the programs. This includes a  
14 breakout by MATs EVA and EVB.

<sup>22</sup> See Exhibit (PG&E-4), WP 18-9, Assumptions and Details, fn.3. [mm] Governor's Exec. Order No. N-79-20 (Sept. 23, 2020), at <<https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf>> Accessed May 23, 2021.

**TABLE 18-10**  
**MWC EV SUMMARY OF EXPENSE FORECAST**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	MAT EVA – Service Inquiry	\$2,975	\$3,811	\$3,435	\$4,990	WP 18-6, line 1
2	MAT EVB – OK to Serve Routine	9,363	6,871	6,733	7,999	WP 18-6, line 2
3	MAT EVB – OK to Serve PEV	40	1,405	726	889	WP 18-6, line 3
4	Other	608				WP 18-6, line 4
5	Aligned to 2021 Budget		(1,208)			WP 18-6, line 6
6	Total	\$12,986	\$10,879	\$10,894	\$13,878	

1           **b. MWC EW – Expense WRO**

2           **1) Relocations**

3           MWC EW Relocations includes a wide variety of work in various  
4           MATs including: non-plant-related relocations of electric facilities;  
5           temporary electric services provided to customers during the  
6           construction of their projects; and Land Department right-of-way  
7           record research requested by third parties that cannot be charged to  
8           a specific project. The forecast for relocation-related expenditures  
9           in MWC EW is indexed to capital WRO expenditures (MWC 10) for  
10          the same period.

11          Table 18-11 shows a summary of the forecast for MWC EW.

**TABLE 18-11**  
**MWC EW – EXPENSE RELOCATIONS FORECAST**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	EW – Expense Relocations Expenditure/Forecast	\$13,878	\$14,550	\$12,242	\$12,056	WP 18-13, line 1

12           The main driver of the decrease between 2020 and 2023 is  
13           corresponding forecast decrease in MWC 10 (WRO Capital) spend,  
14           because the expense relocation forecast is indexed to the WRO

1 Capital forecast, specifically the portion of WRO forecast that is  
2 decreasing based on the RCG economic forecast model.<sup>23</sup>

### 3) **Electric Grid Interconnection**

4 PG&E's EGI Department manages the electric interconnection  
5 process for CPUC and FERC jurisdictional customer generation  
6 projects connected at PG&E's distribution service level.  
7 Interconnection customers pay various fees to PG&E for  
8 these services.

9 PG&E had \$2.4 million in recorded costs for this program in  
10 2020 but, based on current assumptions, PG&E anticipates that  
11 application fees will offset PG&E's expenses for providing services  
12 in the 2021-2023 period and PG&E is not including a forecast for  
13 this program in the 2023 GRC.

14 A summary of EGI-related MWC EW expenditures is shown in  
15 Table 18-12.

**TABLE 18-12**  
**MWC EW – EGI FORECAST**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	EW – EGI Expenditure/Forecast	\$2,353	–	–	–	WP 18-13, line 2

### 3) **MWC EW Electric WRO Expense Forecast Summary**

16 Table 18-13 shows a summary of the forecast for MWC EW as  
17 a sum of the major components of the program: Relocation and  
18 EGI. PG&E is also forecasting \$0.1 million per year in 2022 and  
19 2023 for expense work in support of Electric WRO – State  
20 Infrastructure Projects capital work, which is recorded in MWC 10  
21 and discussed in Section C.2.b.4 below.  
22

<sup>23</sup> See Exhibit (PG&E-4), WP 18-33.

**TABLE 18-13**  
**MWC EW – SUMMARY**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	EW – Expense Relocations	\$13,878	\$14,550	\$12,242	\$12,056	WP 18-13, line 1
2	EW – EGI	2,353	–	–	–	WP 18-13, line 2
3	EW – State Infrastructure	–	177	177	177	WP 18-13, line 3
4	Other	(709)				WP 18-13, line 4
5	Forecasting & Escalation Adjustments		(6,620)	(4,300)	(1,950)	WP 18-13, line 5
6	Total	\$15,521	\$8,106	\$8,118	\$10,283	WP 18-13, line 6

1           **2. Capital MWCs**

2           **a. MWC 16 – Electric NB**

3           **1) MWC 16 – Residential Connects**

4           PG&E forecasts electric NB residential connect expenditures by  
5           multiplying the projected volume of work (measured by forecasting  
6           new connects to PG&E’s distribution system) and the corresponding  
7           unit cost.

8           As in the 2017 and 2020 GRCs, the new connects forecast was  
9           developed using a proprietary econometric model developed by  
10          RCG, a leading independent real estate economics consulting firm  
11          that specializes in California and Bay Area markets. The RCG  
12          model analyzes PG&E historic NB connects data in relation to  
13          historic leading economic indicator data.<sup>24</sup>

14          RCG used a multiple linear regression technique to construct a  
15          forecast of NB connects. Separate forecasts were made for  
16          two connect types: residential and non-residential. The  
17          four relevant indicator variables used in the forecasting models  
18          were: payroll employment growth; unemployment insurance initial  
19          claims; residential permits (units); and non-residential permits,  
20          excluding alterations (valuation).

21          PG&E further breaks down residential connects into three  
22          subcategories: Subdivision Backbone, Subdivision Services, and

---

<sup>24</sup> See Exhibit (PG&E-4), WP 18-29.

1 Other Residential. These subcategories have different unit costs.  
2 The relative volume of work between these three subcategories is  
3 expected to vary during the forecast period. PG&E forecast  
4 volumes of work in each of the three residential subcategories  
5 based on a 3-year (2018-2020) average of the historical ratios  
6 between those categories.

7 Unit costs are based on historical 3-year (2018-2020) averages,  
8 adjusted to nominal 2020 dollars.<sup>25</sup> The increase in the forecast  
9 period related to residential spend is mainly driven by escalation.

10 Table 18-14 shows a summary of the forecast units, unit costs,  
11 and expenditures by sub-category for residential connects.<sup>26</sup>

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<sup>25</sup> See Exhibit (PG&E-4), WP 18-28.

<sup>26</sup> See Exhibit (PG&E-4), WP 18-26, for additional detail.

**TABLE 18-14**  
**MWC 16 – RESIDENTIAL CONNECTS**  
**UNIT, UNIT COST AND EXPENDITURES FORECAST**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	<b>Units (Connects)</b>								
2	Residential – Subdivision Backbone	12,852	11,546	16,330	17,778	19,492	21,167	21,173	WP 18-26, line 1
3	Residential – Subdivision Services	12,852	11,546	16,330	17,778	19,492	21,167	21,173	WP 18-26, line 4
4	Residential – Other	28,669	25,757	36,426	39,656	43,481	47,217	47,230	WP 18-26, line 7
5	<b>Unit Costs</b>								
6	Residential – Subdivision Backbone	\$3,052	\$2,714	\$2,787	\$2,862	\$2,939	\$3,018	\$3,099	WP 18-26, line 2
7	Residential – Subdivision Services	1,119	1,067	1,096	1,126	1,156	1,187	1,219	WP 18-26, line 5
8	Residential – Other	\$5,020	\$4,808	\$4,808	\$4,808	\$4,808	\$4,808	\$4,808	WP 18-26, line 8
9	<b>Expenditure/Forecast (Thousands of Nominal Dollars)</b>								
10	Residential – Subdivision Backbone	\$39,221	\$31,335	\$45,511	\$50,881	\$57,287	\$63,882	\$65,615	WP 18-26, line 3
11	Residential – Subdivision Services	\$14,377	\$12,320	\$17,898	\$20,018	\$22,533	\$25,125	\$25,810	WP 18-26, line 6
12	Residential – Other	\$143,915	\$123,840	\$175,136	\$190,666	\$209,057	\$227,019	\$227,082	WP 18-26, line 9
13	Total – Residential	\$197,513	\$167,495	\$238,545	\$261,565	\$288,877	\$316,026	\$318,507	WP 18-26, line 14

1                   **2) MWC 16 – Non-Residential Connects**

2                   PG&E’s forecast for non-residential connects follows the same  
3                   process as the forecast for residential connects except that  
4                   subcategories are not used. The forecast number of connects is  
5                   based on the RCG model. Unit costs are based on historical 3-year  
6                   averages (2018-2020), adjusted to nominal 2020 dollars. The  
7                   increase in spend is driven mainly by escalation, not by an increase  
8                   in units.

9                   Table 18-15 shows a summary of the forecast units, nominal  
10                  unit costs, and expenditures for non-residential connects.

**TABLE 18-15  
MWC 16 – NON-RESIDENTIAL CONNECTS UNIT,  
UNIT COST AND EXPENDITURES FORECAST**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	Non-residential Connects	8,456	7,025	8,278	8,343	8,363	8,351	8,357	WP 18-26, line 11
2	Non-residential Unit Cost	\$24,404	\$23,115	\$23,115	\$23,115	\$23,115	\$23,115	\$23,115	WP 18-26, line 12
3	Non-residential Connects Expenditure/Forecast (Thousands of Nominal Dollars)	\$206,357	\$162,383	\$191,346	\$192,848	\$193,311	\$193,033	\$193,172	WP 18-26, line 13

(PG&E-4)

**3) MWC 16 – PEV**

PG&E’s forecast for capital improvements related to PEVs in MWC 16 is like the forecast under MWC EV for PEV load checks. PEV capital improvements can be caused directly by new PEV load or may be made in response to a PEV-related load check that finds an existing overload situation on PG&E’s service and distribution facilities. PG&E forecasts the number of customers that will engage with PG&E regarding their PEV service based on projections of: (1) expected PEV sales in PG&E’s service territory<sup>27</sup>; (2) the number of PEV owners that will be placed on PG&E’s residential or non-residential EV rates provided by PG&E’s Clean Transportation Department; and (3) projections of the expected PEV sales and upgrade customer requests in PG&E’s service territory. The forecast now includes the cost of electric distribution infrastructure (i.e., trenching, concrete, electrical wires) on the utility side of the meter, previously funded by third party non-residential customers, and EVCN Phase 2 To-the-Meter expenditures, previously recovered in separate applications. PG&E then calculates a forecast upgrade reinforcement rate based on the 3-year historical (2018-2020) average of PEV service upgrades initiated per number of customers on PG&E’s EV Rates. This upgrade reinforcement rate, times the 3-year average cost per upgrade and AB 841 forecast, is then applied to the projected new PEV accounts on EV rate to derive expected capital costs associated with service upgrades for new PEVs in PG&E’s service territory.

PG&E’s forecast for PEV-related capital expenditures is shown in Table 18-16. The forecast increase in capital PEV costs is due to

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<sup>27</sup> The forecast here is based on PEV sales data supplied by PG&E’s Clean Energy Transportation Department which is based on California Energy Commission’s 2019 Integrated Energy Policy Report. After the MWC 16 forecast was finalized, PG&E concluded that it would be more appropriate to base its assumptions about PEV deployment on internal modelling and data which has been shared with the Commission. PG&E will file errata updating the assumptions and recalculating its forecast as necessary.

- 1 a projected increase in the number of PEVs within PG&E's service
- 2 territory and escalation.

**TABLE 18-16**  
**MWC 16 – PEV-RELATED IMPROVEMENTS**  
**(THOUSANDS OF NOMINAL DOLLARS) FORECAST**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	PEV Related Upgrade Costs	\$19,277	\$5,173	\$14,044	\$40,061	\$50,273	\$66,480	\$90,016	WP 18-42, line 24

**4) MWC 16 – Transformer Purchases**

The NB Program under MWC 16 purchases distribution transformers for all of PG&E’s electric distribution programs.<sup>28</sup> PG&E’s forecast of distribution transformer capital expenditures is based on a forecast for transformer purchases by type multiplied by a 3-year (2018-2020) average unit cost by type. Units for transformer purchases by type are forecast by multiplying: (1) the 3-year (2018-2020) average transformer usage rates per one million dollars spent in programs that use transformers, and (2) the forecast expenditures for those programs. The forecast units are adjusted downward to reflect the fact that some transformers are refurbished and reinstalled after being replaced rather than being newly purchased. Unit costs are determined from a 3-year average by transformer type, adjusted to nominal 2020 dollars. Table 18-17 summarizes the forecast of routine distribution transformer capital expenditures. The main drivers of the forecast increase are: (1) the growth of PG&E’s portfolio of electric distribution programs requiring transformer replacements; (2) projected increased demand for pad mount and overhead transformers; and (3) escalation.

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<sup>28</sup> PG&E purchases both power and current transformers. Power transformers stepdown distribution level voltages (usually 12,000 or 21,000 volts) to voltages normally delivered to customers (120, 240, or 480 volts). Current transformers are utilized in large commercial applications to reduce the total amperage delivered to metering equipment.

**TABLE 18-17**  
**MWC 16 – DISTRIBUTION TRANSFORMER PURCHASES**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	Total Transformer Purchase Expenditures	\$107,281	\$141,570	\$151,725	\$169,068	\$177,997	\$186,789	\$186,981	WP 18-48, line 8

(PG&E-4)

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**5) MWC 16 – Transformer Scrapping**

The number of transformers that need to be scrapped each year is a function of total distribution transformer units in service and failure rate. To forecast units, PG&E uses a linear projection based upon recorded units scrapped. A 3-year (2018-2020) average unit cost, adjusted to nominal 2020 dollars, is used in the forecast. Table 18-18 shows the forecast for transformer scrapping expenditures for 2021-2026.

**TABLE 18-18**  
**MWC 16 – DISTRIBUTION TRANSFORMER SCRAPPING**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Line Description	2020	2021	2022	2023	2024	2025	2026	WP Reference
		Recorded	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	
1	Total Transformer Scrapping Expenditures	\$4,868	\$4,988	\$5,025	\$5,048	\$5,094	\$5,169	\$5,270	WP 18-49, line 2

1                   **6) MWC 16 – Electric NB Forecast Summary**

2                   Table 18-19 shows a summary of the forecast for MWC 16 as a  
3                   sum of major forecasting categories of the program.

**TABLE 18-19**  
**MWC 16 SUMMARY OF CAPITAL FORECAST**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	Residential Connects	\$197,513	\$167,495	\$238,545	\$261,565	\$288,877	\$316,026	\$318,507	WP 18-25, line 1
2	Nonresidential Connects	206,357	162,383	191,346	192,848	193,311	193,033	193,172	WP 18-25, line 2
3	PEV	19,277	5,173	14,044	40,061	50,273	66,480	90,016	WP 18-25, line 3
4	Transformer Purchases	107,281	141,570	151,725	169,068	177,997	186,789	186,981	WP 18-25, line 4
5	Transformer Scrapping	4,868	4,988	5,025	5,048	5,094	5,169	5,270	WP 18-25, line 5
6	Other	895							WP 18-25, line 7
7	2021 Budget Adjustment		30,258						WP 18-25, line 8
8	Forecasting & Escalation Adjustment			(563)	(1,795)	(927)	446	2,186	WP 18-25, line 9
9	Total MWC 16	\$536,190	\$511,868	\$600,122	\$666,795	\$714,625	\$767,943	\$796,132	WP 18-25, line 10

(PG&E-4)

1           **b. MWC 10 – Electric WRO**

2           Capital WRO projects in MWC 10 are forecast based on three  
3 categories: NB-related, Government-related, and State Infrastructure  
4 projects.<sup>29</sup>

5           The forecast methodology for the NB-related and  
6 Government-related WRO is based on specific economic indicators tied  
7 to PG&E's service territory as opposed to California as a whole. This  
8 forecast is based a proprietary economic model developed by RCG, the  
9 same economic consultants that PG&E uses to help prepare its forecast  
10 for MWC 16 NB connects forecast. The RCG model analyzes PG&E  
11 historic NB-related and Government-related WRO data in relation to  
12 historic leading economic indicator data.<sup>30</sup>

13           **1) MWC 10 – NB Related WRO**

14           The forecast methodology for NB-related WRO is based on  
15 RCG's WRO model, and then adjusted to account for  
16 reimbursements from customers. The RCG model, which is a  
17 function of multifamily permitting, PPI inflation, and a seasonal  
18 adjustment factor, uses a multiple linear regression technique to  
19 construct a forecast of gross expenditures for NB-related WRO  
20 work.<sup>31</sup> However, because customers share some of the cost of  
21 NB-related WRO projects, the output of the RCG model is adjusted  
22 by subtracting out forecast annual reimbursements from customers,  
23 based on a 3-year (2018-2020) historical average.

24           Based on the RCG model and forecast reimbursements, PG&E  
25 forecasts that its 2023 capital expenditures will be \$24.2 million less  
26 than 2020 recorded expenditures.

27           Table 18-20 shows the forecast of NB-related WRO using this  
28 methodology.

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**29** In previous GRCs, PG&E used a fourth forecasting category – Major Projects. However, PG&E is not forecasting any expenditures in Major Projects during the 2023 GRC time period.

**30** See Exhibit (PG&E-4), WP 18-56.

**31** See Exhibit (PG&E-4), WP 18-56.

**TABLE 18-20**  
**MWC 10 NB-RELATED WRO**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	NB-Related WRO Net Expenditures	\$76,632	\$44,586	\$46,919	\$52,359	\$58,889	\$65,819	\$83,823	WP 18-55, line 4

(PG&E-4)

1                   **2) MWC 10 – Government-Related WRO**

2                   Similar to NB-related WRO, the forecast methodology for  
3                   Government-related WRO is based on RCG’s WRO model, adjusted  
4                   to account for reimbursements from customers. The RCG model for  
5                   Government-related WRO, which is a function of federal grants to  
6                   state and local governments for transportation projects, uses a  
7                   multiple linear regression technique to construct a forecast for gross  
8                   expenditures.<sup>32</sup> Again, because customers share some of the cost  
9                   of government-related WRO projects, the output of the RCG model  
10                  is adjusted by subtracting out forecast annual reimbursements from  
11                  customers based on a 3-year (2018-2020) historical average.

12                  Based on this methodology, PG&E forecasts a \$5.0 million  
13                  decrease in Government-related WRO spending in 2023 compared  
14                  to 2020 recorded.

15                  Table 18-21 shows the forecast of Government-related WRO  
16                  using this methodology.

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<sup>32</sup> See Exhibit (PG&E-4), WP 18-56.

**TABLE 18-21  
MWC 10 GOVERNMENTAL-RELATED WRO  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	Government- Related WRO Net Expenditures	\$69,476	\$58,727	\$74,540	\$64,536	\$61,878	\$66,662	\$67,082	WP 18-55, line 8

(PG&E-4)

1           **3) MWC 10 – Major Projects**

2           In addition to the indexed forecast components discussed in the  
3           previous two sections, PG&E has identified several large WRO  
4           projects that are now near completion. These projects have  
5           \$0.3 million in recorded costs for 2020, but PG&E is not forecasting  
6           any additional costs in the 2021-2026 timeframe.

7           **4) MWC 10 – State Infrastructure Projects**

8           The State Infrastructure Projects portfolio has large-scale  
9           projects with schedules and scope determined by third parties,  
10          typically state and local governments. The portfolio request for  
11          MWC 10 includes forecasted costs for relocation of electric  
12          distribution assets for the three projects discussed below.<sup>33</sup>

13          Given the evolving scope and schedules provided by these third  
14          parties, there are varying levels of cost assumptions for each  
15          project:

16          California High-Speed Rail: The costs included for the  
17          High-Speed Rail project are associated with forecasted relocation  
18          work along the rail corridor between Silicon Valley and Bakersfield.  
19          Existing contracts with the California High Speed Rail Authority  
20          (CHSRA) dictate that costs for the relocation of electric distribution  
21          facilities are to be borne by CHSRA, except for credits PG&E will  
22          owe to the CHSRA for betterment, salvage, and depreciation.  
23          PG&E recorded (\$0.1) million in expenditures for this project in 2020  
24          and forecasts \$2.6 million in 2021, \$4.3 million in 2022, \$2.9 million  
25          in 2023, a nominal amount in 2024, and no costs in 2025 and  
26          2026.<sup>34</sup> The increase between 2020 recorded and the 2023  
27          forecast is due to the timing of the reimbursements that occurred in  
28          2020, which resulted in a negative \$0.1 million recorded amount.

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**33** Details about the cost forecasts for these projects can be found in the Project Summary and Cost/Benefit Analysis. In the 2020 GRC, PG&E included a forecast for Caltrain Electrification in the Peninsula Corridor. That project was completed in 2019.

**34** See Exhibit (PG&E-4), WP 18-66.

1                    Google – South Bay Redevelopment Program<sup>35</sup>: This project  
2 involves relocation of existing electric and gas transmission and  
3 distribution facilities and installation of new electric and gas  
4 distribution facilities to support a large mix-used development  
5 project in multiple locations in San Jose, Sunnyvale, and Mountain  
6 View. The parties have not yet agreed on how the costs for PG&E’s  
7 electric distribution facility relocations will be allocated; however,  
8 given that these facilities are in franchise, the forecast assumes that  
9 PG&E will bear some of the relocation costs. PG&E forecasts  
10 \$0 million in expenditures in 2021, \$12 million in 2022, \$3 million in  
11 2023, \$5.3 million in 2024 and no additional costs in 2025 and 2026.  
12 This forecast relates to the electric distribution portion of the work  
13 only.

14                    The BART Silicon Valley Phase II Extension<sup>36</sup>: This project  
15 involves the relocation, protection in place, or abandonment of  
16 PG&E gas and electric facilities in connection with a six-mile  
17 extension of current BART service from North Berryessa station to  
18 Santa Clara. PG&E expects that the project will begin in 2021 and  
19 be completed in 2024. PG&E did not have a forecast for this project  
20 at the time the GRC forecast was finalized.

21                    These projects are summarized in Table 18-22 below.

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**35** This project was discussed in the 2020 GRC as “San Jose Diridon Station Area Redevelopment.”

**36** This program was discussed in the 2020 GRC as “Santa Clara County VTA Phase II Extension of BART to San Jose.”

TABLE 18-22  
MWC 10 – STATE INFRASTRUCTURE PROJECTS EXPENDITURES  
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Line Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	California High-Speed Rail	\$(91)	\$2,648	\$4,310	\$2,881	\$25	-	-	WP 18-65, line 1
2	Caltrain Electrification	(545)	-	-	-	-	-	-	WP 18-65, line 2
3	VTA- BART to Silicon Valley Phase II	-	-	-	-	-	-	-	WP 18-65, line 4
4	Google	-	-	11,980	3,080	5,280	-	-	WP 18-65, line 3
5	Total State Infrastructure Projects	\$(637)	\$2,648	\$16,290	\$5,961	\$5,305	-	-	WP 18-65, line 5

1 **D. Compliance with Prior Commission Decisions**

2 **1. Compliance with Section 5.2 of the 2020 GRC Settlement Agreement**  
3 **(“Deferred Work Principles”)**

4 The 2020 GRC Settlement Agreement requires PG&E to include  
5 testimony in this GRC on deferred work if the following criteria are met:

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

13 Work that was authorized in the 2020 GRC for the MWCs in this chapter  
14 was not represented as needed to provide safe and reliable service,  
15 therefore Check 1 does not apply. Based on the results of this analysis, this  
16 chapter does not include deferred work as defined by the 2020 GRC  
17 Settlement Agreement.<sup>37</sup>

18 **2. Decision (D.) 20-05-008 - Caltrain Settlement**

19 In D.20-05-008, issued on May 14, 2020, the Commission approved a  
20 settlement agreement between PG&E and the Peninsula Corridor Joint  
21 Powers Board (Caltrain) (Settlement or Settlement Agreement) regarding  
22 allocation of the capital costs required for PG&E to convert and upgrade two  
23 PG&E substations – FMC in San Jose and East Grand in South San  
24 Francisco – with breaker-and-a-half configurations. Caltrain provides  
25 commuter rail service between San Jose and San Francisco and the  
26 substation construction is associated with the Caltrain electrification project  
27 which will displace the current diesel fuel source with electricity.

28 The Caltrain electrification project will further California’s energy policy  
29 priorities to reduce greenhouse gas emissions and to electrify the

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37 See Exhibit (PG&E-4), WP 2-13.

1 transportation sector.<sup>38</sup> In particular, by its displacement of diesel fuel, the  
2 electrification project will reduce greenhouse gas emissions by up to  
3 97 percent as compared to the current diesel service, and thus improve  
4 regional air quality. Additionally, electrification will reduce noise along the  
5 Peninsula corridor and it will enable Caltrain to run more trains per hour,  
6 which will benefit commuters. In addition to the direct project benefits,  
7 PG&E's customers will also receive general operating benefits from  
8 upgrading and modernizing the 70-year-old East Grand and 40-year-old  
9 FMC substations.

10 Under the terms of the PG&E/Caltrain agreements, Caltrain has had the  
11 obligation to advance all funds necessary for PG&E to construct the  
12 facilities. Caltrain has also paid PG&E an additional amount on these  
13 capital costs to reimburse PG&E for the Income Tax Component of  
14 Contributions (ITCC) associated with Caltrain's funding. As of May 31,  
15 2021, Caltrain will have paid PG&E just under \$95 million in construction  
16 costs and associated ITCC.

17 In Resolution E-4886, the Commission ordered PG&E to file an  
18 application to address the manner in which the ultimate financial  
19 responsibility for the capital costs to be incurred for the Caltrain  
20 electrification project should be allocated between PG&E and Caltrain. In  
21 December 2018, PG&E filed Application 18-12-017 in response to  
22 Resolution E-4886. After substantial negotiations, PG&E and Caltrain  
23 entered into the Settlement Agreement, which the Commission approved in  
24 D.20-05-008.

25 The Settlement provides that Caltrain shall retain the financial  
26 responsibility for 40 percent of the capital costs of PG&E's  
27 substation-related construction activities and that the remaining 60 percent  
28 of costs shall be allocated to and recovered from PG&E's other customers.  
29 To the extent that Caltrain has paid PG&E more than its 40 percent share of  
30 capital costs, PG&E must reimburse these capital costs to Caltrain. The

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**38** The Clean Energy and Pollutions Reduction Act of 2015, Sen. Bill No. 350 (2015-2016 Reg. Sess.) (De Leon); see *a/so* Pub. Util. Code § 740.12(B) ("Widespread transportation electrification is needed to achieve the goals of the Charge Ahead California Initiative . . .").

1 Settlement Agreement also provides that Caltrain remains obligated for the  
2 full ITCC rate on the amount of its capital cost payments. Importantly,  
3 although Caltrain began making payments in 2017, and has already paid  
4 PG&E more than 40 percent of the estimated cost of the projects, the  
5 Settlement provides that PG&E shall not reimburse Caltrain any amount  
6 until both this Commission and the FERC authorize PG&E's rate recovery  
7 associated with its reimbursement obligation to Caltrain. Additionally, under  
8 the terms of the Settlement, PG&E has no obligation to pay any interest on  
9 the reimbursed amount.

10 In approving the Settlement Agreement, the Commission added as a  
11 condition of PG&E being authorized rate recovery that the Energy Division  
12 would retain and oversee an independent third-party auditor to assess  
13 PG&E's construction costs and that "the results of the audit will inform the  
14 prudence of [the PG&E-incurred] costs."<sup>39</sup> The Commission explained that  
15 the decision was intended "to enable PG&E to seek recovery of [the Caltrain  
16 electrification] project costs in its 2023 GRC but still ensure the audit results  
17 will be available for parties' and the Commission's examination during that  
18 proceeding; and to clarify that PG&E may seek recovery of the costs of the  
19 audit."<sup>40</sup>

20 PG&E estimates that the total cost of the Caltrain electrification project  
21 will be approximately \$139 million.<sup>41</sup> More than 90 percent of project costs  
22 are attributable to PG&E's transmission assets; PG&E will seek to recover  
23 this portion of the costs at the FERC in its upcoming 2022 Transmission  
24 Owner rate proceeding. In this GRC, PG&E is only seeking recovery for  
25 costs attributable to PG&E's electric distribution CPUC-jurisdictional system.

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**39** D.20-05-008, p. 10.

**40** D.20-05-008, pp. 15-16.

**41** The decision approving the Settlement Agreement ordered PG&E to provide an estimate of the total costs of the Caltrain electrification project. D.20-05-008, p. 18, OP 3 (ordering PG&E to file within 10 days of the D.20-05-008 decision a Tier 1 advice letter "detailing its current estimate of the total project costs as of the issue date of this decision.") PG&E complied with this requirement by filing Advice Letter 5833-E. In that filing, PG&E submitted the cost estimates reflected in the Settlement Agreement, which indicated at the AACE Class 3 level that the total capital costs of the Caltrain electrification project would be approximately \$106.9 million and that, with an AACE Class 3 contingency of 30 percent, the total cost could be approximately \$139 million.

1 PG&E's allocation between the FERC- and CPUC-jurisdictional costs of the  
2 project is based on actual costs incurred to date and cost estimates for the  
3 remaining work, which will be almost all FERC-jurisdictional.

4 PG&E estimates that total CPUC-jurisdictional costs will be \$10 million.  
5 Based on that estimate, PG&E is requesting in this GRC that \$6 million be  
6 included in rate base to account for its eventual reimbursement of  
7 60 percent of project costs to Caltrain. PG&E has included the revenue  
8 requirement corresponding to the addition of that \$6 million in rate base in  
9 its overall requested revenue requirement. PG&E currently estimates that  
10 construction at the East Grand substation will be completed in January 2022  
11 and construction at the FMC substation will be completed in by May 2022, at  
12 which point the auditor retained by the Energy Division will audit the project  
13 costs in accordance with D.20-05-008.<sup>42</sup> If the audit is completed while  
14 Phase 1 of this GRC is still pending, PG&E will submit supplemental  
15 testimony in this proceeding presenting the audit.

16 If the audit cannot be completed in time for PG&E to present the costs  
17 for the Caltrain electrification project in Phase 1 of this GRC, PG&E requests  
18 permission to seek those costs through a Tier 2 advice letter. PG&E  
19 proposes to file any such advice letter within 30 days after the audit is  
20 completed. A Tier 2 advice letter would allow the issue to be handled  
21 expeditiously and would provide an opportunity for review by Commission  
22 staff and protest by parties. If PG&E proceeds via advice letter, PG&E  
23 would remove the revenue requirement associated with the \$6.0 million  
24 requested increase in its rate base from its 2023 GRC revenue requirement.

## 25 E. Cost Tables

26 The expense and capital forecasts for NB/WRO are summarized in the  
27 following tables:

- 28 • Table 18-23 lists the expense MWCs, showing 2016 through 2020  
29 recorded expenses and 2021 through 2023 forecast expenses.

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<sup>42</sup> PG&E has discussed with the Commission the possibility of beginning the audit when the work at the East Grand substation is complete.

- 1           • Table 18-24 lists the capital MWCs, showing 2016 through 2020
- 2           recorded expenditures and 2021 through 2026 forecast expenses,
- 3           including the AB 841-related PEV capital costs.

**TABLE 18-23  
EXPENSE  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded 2016	Recorded 2017	Recorded 2018	Recorded 2019	Recorded 2020	Forecast 2021	Forecast 2022	Forecast 2023	WP Reference
1	EV	Manage Service Inquiries	\$8,998	\$9,835	\$11,074	\$10,240	\$12,986	\$10,879	\$10,894	\$13,878	WP 18-1, line 1
2	EW	E TD WRO – Maintenance	12,607	4,390	8,759	6,107	15,521	8,106	8,118	10,283	WP 18-1, line 2
3	Total		\$21,605	\$14,225	\$19,833	\$16,347	\$28,507	\$18,985	\$19,013	\$24,161	

**TABLE 18-24  
CAPITAL  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded 2016	Recorded 2017	Recorded 2018	Recorded 2019	Recorded 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	WP Reference
1	10	E Dist WRO General	\$99,694	\$97,298	\$121,047	\$120,864	\$145,630	\$155,690	\$145,048	\$132,769	\$139,842	\$150,827	\$176,341	WP 18-17, line 1
2	16	E Dist Customer Connects	359,943	362,270	434,560	461,986	536,190	511,868	600,122	666,795	714,625	767,943	796,132	WP 18-17 line 2
3	Total		\$459,637	\$459,568	\$555,607	\$582,850	\$681,819	\$667,558	\$745,170	\$799,564	\$854,467	\$918,770	\$972,473	

**PACIFIC GAS AND ELECTRIC COMPANY  
2023 GENERAL RATE CASE**

Testimony   X   Workpapers \_\_\_\_\_ SOQ \_\_\_\_\_

Exhibit Number:   PG&E-4   Chapter Number:   18  

Chapter Title:   New Business And Work At The Request Of Others  

Witness Name:   Josh Jones  

Page No.	Line No.	Item	As Filed	As Corrected
<b>Errata as of November 5, 2021</b>				
18-3	Lines 3-6	2021-2026 Forecast	2021 Forecast \$688.3 2022 Forecast \$748.5 2023 Forecast \$799.3 2024 Forecast \$843.1 2025 Forecast \$896.4 2026 Forecast \$929.1	2021 Forecast \$667.6 2022 Forecast \$745.2 2023 Forecast \$799.6 2024 Forecast \$854.5 2025 Forecast \$918.8 2026 Forecast \$972.5
18-3	Line 8	2023 vs 2020	\$117.5	\$117.7
18-4	Figure 18-2	Capital Expenditures	2021 Forecast \$688,254 2022 Forecast \$748,505 2023 Forecast \$799,328 2024 Forecast \$843,136 2025 Forecast \$896,384 2026 Forecast \$929,069	2021 Forecast \$667,558 2022 Forecast \$745,170 2023 Forecast \$799,564 2024 Forecast \$854,467 2025 Forecast \$918,770 2026 Forecast \$972,473
18-4 Table 18-2	Line 1	2021-2026 Forecast	2021 Forecast \$532,564 2022 Forecast \$603,457 2023 Forecast \$666,559 2024 Forecast \$703,294 2025 Forecast \$745,557 2026 Forecast \$752,728	2021 Forecast \$511,868 2022 Forecast \$600,122 2023 Forecast \$666,795 2024 Forecast \$714,625 2025 Forecast \$767,943 2026 Forecast \$796,132
18-4 Table 18-2	Line 3	2021-2026 Total Forecast	2021 Forecast \$688,254 2022 Forecast \$748,505 2023 Forecast \$799,328 2024 Forecast \$843,136 2025 Forecast \$896,384 2026 Forecast \$929,069	2021 Forecast \$667,558 2022 Forecast \$745,170 2023 Forecast \$799,564 2024 Forecast \$854,467 2025 Forecast \$918,770 2026 Forecast \$972,473

18-12	Figure 18-5	NB Capital Forecast	2021 Forecast \$532,564 2022 Forecast \$603,457 2023 Forecast \$666,559 2024 Forecast \$703,294 2025 Forecast \$745,557 2026 Forecast \$752,728	2021 Forecast \$511,868 2022 Forecast \$600,122 2023 Forecast \$666,795 2024 Forecast \$714,625 2025 Forecast \$767,943 2026 Forecast \$796,132
18-32 Table 18-16	Line 1	2021-2026 Forecast	2021 Forecast \$25,869 2022 Forecast \$17,379 2023 Forecast \$39,825 2024 Forecast \$39,942 2025 Forecast \$44,094 2026 Forecast \$46,612	2021 Forecast \$5,173 2022 Forecast \$14,044 2023 Forecast \$40,061 2024 Forecast \$50,273 2025 Forecast \$66,480 2026 Forecast \$90,016
18-38 Table 18-19	Line 3	2021-2026 Forecast	2021 Forecast \$25,869 2022 Forecast \$17,379 2023 Forecast \$39,825 2024 Forecast \$38,942 2025 Forecast \$44,094 2026 Forecast \$46,612	2021 Forecast \$5,173 2022 Forecast \$14,044 2023 Forecast \$40,061 2024 Forecast \$50,273 2025 Forecast \$66,480 2026 Forecast \$90,016
18-38 Table 18-19	Line 9	2021-2026 Forecast	2021 Forecast \$532,564 2022 Forecast \$603,457 2023 Forecast \$666,559 2024 Forecast \$703,294 2025 Forecast \$745,557 2026 Forecast \$752,728	2021 Forecast \$511,868 2022 Forecast \$600,122 2023 Forecast \$666,795 2024 Forecast \$714,625 2025 Forecast \$767,943 2026 Forecast \$796,132
18-51 Table 18-24	Line 2	2021-2026 Forecast	2021 Forecast \$532,564 2022 Forecast \$603,457 2023 Forecast \$666,559 2024 Forecast \$703,294 2025 Forecast \$745,557 2026 Forecast \$752,728	2021 Forecast \$511,868 2022 Forecast \$600,122 2023 Forecast \$666,795 2024 Forecast \$714,625 2025 Forecast \$767,943 2026 Forecast \$796,132
18-51 Table 18-24	Line 3	2021-2026 Forecast	2021 Forecast \$688,254 2022 Forecast \$748,505 2023 Forecast \$799,328 2024 Forecast \$843,136 2025 Forecast \$896,384 2026 Forecast \$929,069	2021 Forecast \$667,558 2022 Forecast \$745,170 2023 Forecast \$799,564 2024 Forecast \$854,467 2025 Forecast \$918,770 2026 Forecast \$972,473

**PACIFIC GAS AND ELECTRIC COMPANY**

**CHAPTER 19**

**RULE 20A**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 19  
RULE 20A

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1                                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                                   **CHAPTER 19**  
3                                   **RULE 20A**

4   **A. Introduction**

5       **1. Scope and Purpose**

6                   The purpose of this chapter is to demonstrate that Pacific Gas and  
7                   Electric Company's (PG&E) forecast of capital expenditures for PG&E's  
8                   Electric Rule 20A Program is reasonable and should be approved.

9       **2. Summary of Request**

10                  PG&E requests that the California Public Utilities Commission (CPUC or  
11                  Commission) adopt PG&E's capital expenditure forecast for the Rule 20A  
12                  Program of \$47.3 million in 2021, \$40.0 million in 2022, \$39.9 million in  
13                  2023, \$41.0 million in 2024, \$42.1 million in 2025, and \$43.2 million in 2026.  
14                  PG&E's 2023 forecast of \$39.9 million is \$1.6 million higher than its 2020  
15                  expenditures of \$38.3 million.<sup>1</sup>

16                  Consistent with the June 3, 2021 final decision on Phase 1 of  
17                  R.17-05-010, Order Instituting Rulemaking to Consider Revisions to Electric  
18                  Rule 20 and Related Matters (Rule 20 OIR), after 2022 PG&E will  
19                  discontinue the allocation of new work credits for Rule 20A projects.<sup>2</sup>

20                  Finally, PG&E proposes to continue the Rule 20A one-way balancing  
21                  account ordered in the 2017 and 2020 General Rate Cases (GRC) through  
22                  the 2023 GRC period. This proposal is consistent with the final decision of  
23                  Phase 1 of the Rule 20 OIR, which requires PG&E to establish a balancing  
24                  account for all of its Rule 20 programs.<sup>3</sup>

25                  Forecasts in this chapter are shown with escalation at the Major Work  
26                  Category (MWC) level and escalation is included in all expense and capital  
27                  totals. For more information on escalation, please refer to Chapter 2 of this  
28                  exhibit.

---

1   See Exhibit (PG&E-4), Workpaper (WP) 19-1, line 2.

2   D.21-06-013.

3   D.21-06-013. PG&E will update its 2023 GRC content for other Rule 20 programs as needed to comply with this decision and any subsequent decisions.

1       **3. Overview of Recorded and Forecast Costs**

2               Rule 20A capital expenditures are recorded in Major Work Category  
3               (MWC) 30, as shown in Table 19-1. Program expenses (costs related to  
4               audits, cancelled projects, and development of Rule 20 Guidebook) are not  
5               forecast but are recorded in MWC IG as they are incurred.

**TABLE 19-1  
RULE 20A MAJOR WORK CATEGORIES**

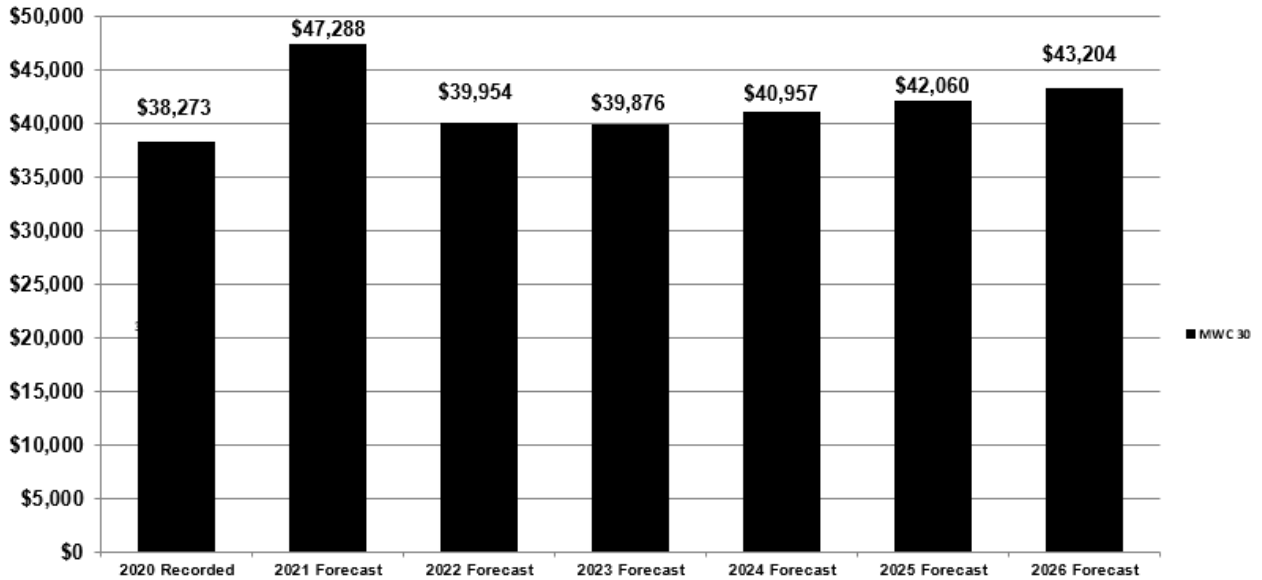
Line No.	MWCs	Description
1	<u>Expense MWC</u>	
2	IG	Manage Various Balancing Account Processes
3	<u>Capital MWC</u>	
4	30	Electric Distribution Work at the Request of Others – Rule 20A

6               Figure 19-1 shows the 2020 recorded and 2021-2026 forecast capital  
7               expenditures for the Rule 20A Program.<sup>4</sup> The forecast for 2021 is higher  
8               than historical expenditures due to the volume of construction scheduled for  
9               2021. PG&E's 2023-2026 forecast assumes that its existing Rule 20A  
10              one-way balancing account will be allowed to be carried over into 2023.

---

<sup>4</sup> See Exhibit (PG&E-4), WP 19-1, line 2.

**FIGURE 19-1  
CAPITAL RECORDED AND FORECAST BY MWC 2020-2026  
(THOUSANDS OF NOMINAL DOLLARS)**



1        **4. Support for Request**

2                Rule 20A undergrounding work is performed at the request of  
3 governmental agencies. PG&E has received project requests that support  
4 the forecast from the governmental agencies.

5        **5. Organization of the Remainder of This Chapter**

6                The remainder of this chapter is organized as follows:

- 7                • Section B – Program and Risk Overview;
- 8                • Section C – Activities, Costs, and Forecast Drivers by MWC;
- 9                • Section D – Estimating Method;
- 10              • Section E – Compliance With Prior Commission Decisions;
- 11              • Section F – Rule 20A Balancing Account;
- 12              • Section G – Work Credit Allocations; and
- 13              • Section H – Cost Tables.

1 **B. Program and Risk Overview**

2 **1. Program Description**

3 **a. Program Overview**

4 PG&E’s Rule 20A Program allows governmental agencies to  
5 underground existing overhead electric facilities if their projects meet the  
6 following specific criteria:<sup>5</sup>

- 7 1) The proposed undergrounding work will avoid or eliminate an  
8 unusually heavy concentration of overhead electric facilities;
- 9 2) The street or road or Right-of-Way (ROW) is extensively used by the  
10 general public and carries a heavy volume of pedestrian or vehicular  
11 traffic;
- 12 3) The street or road or ROW adjoins or passes through a civic area or  
13 public recreation area or an area of unusual scenic interest to the  
14 general public; and
- 15 4) The street or road or ROW is considered an arterial street or major  
16 collector as defined in the Governor’s Office of Planning and  
17 Research General Plan Guidelines.

18 Rule 20A work credits for undergrounding have historically been  
19 allocated to each governmental agency served by PG&E’s electric  
20 distribution system according to an established formula.<sup>6</sup> The  
21 accumulated work credits do not represent actual funds in a financial  
22 account. Once a governmental agency has accumulated enough work  
23 credits and is ready to proceed with a specific project, the project is  
24 added to PG&E’s Rule 20A project queue.

25 Representatives from any governmental agency seeking to pursue a  
26 Rule 20A undergrounding project must meet with PG&E’s Rule 20A  
27 Liaison to determine whether the project meets the Rule 20A criteria,  
28 and whether enough work credits are available to complete the  
29 proposed undergrounding project. Under Rule 20A.1, the governmental  
30 agency must hold a public hearing and pass an ordinance or resolution

---

5 PG&E will modify these criteria as needed to comply with D.21-06-013.

6 As discussed in Section G, below, PG&E is discontinuing the allocation of new work credits after 2022.

1 to create an underground district. The ordinance addresses items such  
2 as the underground district boundaries and whether a project is tied to  
3 road widening improvements; it also outlines the project's qualification  
4 for funding under Rule 20A. Once the Rule 20A Liaison has verified that  
5 a project qualifies and sufficient work credits are available, the  
6 governmental agency and PG&E sign the General Conditions  
7 Agreement, which sets forth the parties' responsibilities, and the project  
8 is put into the design queue.

9 On May 19, 2017, the CPUC opened the Rule 20 OIR to review and  
10 revise the Rule 20 Program statewide. On June 3, 2021, the CPUC  
11 approved D.21-06-013, the final decision on Phase 1 of the Rule 20  
12 OIR. As further discussed in Section E.3, below, PG&E has  
13 incorporated relevant requirements from that decision into its testimony  
14 here. Phase 2 of the Rule 20 OIR remains open and may require  
15 additional changes to Rule 20A.

16 **b. Management Structure**

17 PG&E manages the Rule 20A Program through the Electric  
18 Distribution Operations line of business. The Rule 20A Program  
19 organization consists of a manager, project managers, program liaisons  
20 and analysts. The manager provides the program expertise and  
21 oversight ensuring regulatory compliance. The project managers  
22 execute the projects from the design phase to closing. The program  
23 liaisons work directly with governmental agencies to qualify their  
24 projects during the project initiation phase. The analysts support the  
25 program with respect to financial items. Specific analyst work includes  
26 city and county work credit balances and ledger oversight, reporting  
27 project expenditures and forecasts, CPUC annual reporting and data  
28 requests, and compliance reporting.

29 **2. Risk Controls and Mitigations**

30 Risk controls and mitigations are aligned to various MWCs and  
31 Maintenance Activity Types in Electric Distribution. None of the work  
32 presented in this chapter corresponds to a risk mitigation or risk control that  
33 addresses a risk on Electric Operations Corporate Risk Register. More

1 information about risk mitigations and controls is in PG&E's Electric  
2 Distribution Risk Management testimony (Exhibit (PG&E-4), Chapter 3).

### 3 **C. Activities, Costs, and Forecast Drivers by MWC**

#### 4 **1. Rule 20A Expense (MWC IG)**

5 The Rule 20A Program uses MWC IG to record any expense items,  
6 such as costs for required audits. In addition, incurred expenditures for  
7 cancelled projects are converted to expense to be recorded in the Rule 20A  
8 balancing account. The Rule 20 OIR Phase 1 Decision directs utilities to  
9 develop a Rule 20 Guidebook allows costs associated with the Guidebook to  
10 be expensed.<sup>7</sup> As these costs vary from year to year, PG&E does not  
11 forecast these potential costs in the GRC but does record amounts in the  
12 Rule 20A balancing account.<sup>8</sup>

#### 13 **2. Rule 20A Program Capital (MWC 30)**

14 PG&E's recorded 2020 capital expenditures of \$38.3 million were  
15 \$4.5 million more than the imputed amount authorized of \$33.4 million  
16 authorized for 2020 in PG&E's 2020 GRC.<sup>9</sup> PG&E is intentionally  
17 expending more than authorized imputed amount to reduce the remaining  
18 balance in the one-way Rule 20A balancing account.

19 PG&E's 2023 GRC forecast was developed based on the 3-year  
20 average (2018-2020) expenditures, adjusted to reflect variability in project  
21 execution schedules. The forecast for 2021 is higher than historical  
22 expenditures due to the volume of construction scheduled for 2021. With  
23 escalation, and assuming some spending from the existing balance in the  
24 Rule 20A balancing account, PG&E's 2023 GRC forecast for Rule 20A is  
25 \$39.9 million for 2023, \$41 million for 2024, \$42.1 million for 2025, and  
26 \$43.2 million for 2026.<sup>10</sup>

---

7 D.21-06-013.

8 See Exhibit (PG&E-4), WP 19-12, line 2.

9 See PG&E's 2020 Risk Spending Accountability Report for year 2020 (March 21, 2021), p. 3-3.

10 See Exhibit (PG&E-4), WP 19-1, line 2.

## 1 **D. Estimating Method**

2 As described above in Section B.1, PG&E is basing its 2023 forecast on  
 3 a three-year average (2018-2020) of Rule 20A recorded expenditures.<sup>11</sup>  
 4 Forecasts for 2021 and 2022 are based on known project work, adjusted to  
 5 reflect variability in project timelines. A similar adjustment slightly reduces  
 6 the 2023 forecast from the calculated three year average.

## 7 **E. Compliance with Prior Commission Decisions**

### 8 **1. Compliance With Section 5.2 of the 2020 GRC Settlement Agreement** 9 **(“Deferred Work Principles”)**

10 The 2020 GRC Settlement Agreement requires PG&E to include  
 11 testimony in this GRC on deferred work if the following criteria are met:

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

19 Work that was authorized in the 2020 GRC for MWCs in this chapter  
 20 was not represented as needed to provide safe and reliable service,  
 21 therefore Check 1 does not apply. Based on the results of this analysis, this  
 22 chapter does not include deferred work as defined by the 2020 GRC  
 23 Settlement Agreement.<sup>12</sup>

### 24 **2. Completion of 2017 Audit of the Rule 20A Program**

25 In the 2017 GRC Decision, the Commission ordered an audit of the Rule  
 26 20A Program “to ensure that PG&E has fully accounted for annual Rule 20A  
 27 budgeted amounts, and ... that localities will receive the full benefit of these  
 28 funds.”<sup>13</sup> The audit was completed in October 2019 and comments and

---

11 See Exhibit (PG&E-4), WP 19-8, “Planned Expenditures and Balancing Account Carryover.”

12 See Exhibit (PG&E-4), WP 2-13.

13 D.17-05-013, p. 244, Conclusion of Law (COL) 7.

1 reply comments pertaining to the audit report have been filed. The CPUC  
2 entered the audit report into the record of the Rule 20 OIR proceeding.

### 3 **3. Rule 20 OIR Phase 1 Final Decision**

4 As discussed above, on June 3, 2021, the CPUC approved  
5 D.21-06-013, the final decision of Phase 1 of the Rule 20 OIR. Among other  
6 things, the decision requires PG&E and other utilities with Rule 20 programs  
7 to: (1) establish balancing accounts for their Rule 20 programs, including  
8 separate tracking of each type of Rule 20 program; and (2) discontinue the  
9 issue of Rule A work credits. PG&E believes that its existing Rule 20A  
10 balancing account complies with the decision with respect to Rule 20A.<sup>14</sup>

### 11 **F. Rule 20A Balancing Account**

12 The 2017 GRC Decision ordered PG&E to establish a one-way balancing  
13 account for the Rule 20A Program.<sup>15</sup> The decision further provided that any  
14 over-collected balance in the account would remain available for future Rule 20A  
15 projects and that the Commission would review the balance in the next GRC  
16 proceeding.<sup>16</sup> The 2020 GRC Decision continued the one-way balancing  
17 account and again provided that any over-collected balance in the account  
18 would remain available for future Rule 20A projects and that the Commission  
19 would review the balance in the next GRC proceeding.<sup>17</sup> D.21-06-013 supports  
20 the continuation of the existing one-way balancing account.

21 PG&E proposes that the carry-over of any over-collected balances for use in  
22 future projects be continued in the 2023 GRC. Based on 2020 recorded costs  
23 and PG&E's current forecast for 2021 and 2022, PG&E estimates that there will  
24 be a \$32.7 million balance in the Rule 20A balancing account at the end of 2022  
25 that will be available to fund projects in the 2023 GRC period.<sup>18</sup> PG&E's

---

**14** PG&E's Rule 20B and 20C programs, which are part of PG&E's New Business and Work at the Request of Others forecast discussed in Chapter 18 of this exhibit, do not currently receive balancing account treatment. PG&E is investigating the best mechanism for complying the D.21-06-013 requirements for these programs.

**15** D.17-05-013, p. 249, Ordering Paragraph (OP) 10.

**16** D.17-05-013, p. 249, OP 10.

**17** D.20-12-005, p. 396, COL 27.

**18** See Exhibit (PG&E-4), WP 19-8, lines 6 and 11.

1 forecast for the 2023-2026 period assumes that this estimated \$32.7 million will  
2 be available to fund work in addition to the amount forecast in this GRC.

3 **G. Work Credit Allocations**

4 As discussed above, PG&E historically allocated work credits to  
5 communities served by its electric distribution system according to an  
6 established formula. The 2017 and 2020 GRC decisions set the annual work  
7 credit allocations at \$41.3 million.

8 D.21-06-013 requires PG&E and other utilities to discontinue the issuance of  
9 work credits after 2022. Therefore PG&E is not requesting approval of any work  
10 allocation in this GRC.

11 **H. Cost Tables**

12 The recorded and forecast costs for the Rule 20A Program (MWCs IG  
13 and 30) are shown below in Tables 19-2 and 19-3.

**TABLE 19-2  
EXPENSE  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast			WP Reference	
			2016	2017	2018	2019	2020	2021	2022	2023		
1	IG	Manage Various Balance Account Processes	-	-	\$797	\$1,219	\$(65)	-	-	-	-	WP 19-11, line 1
2		Total	-	-	\$797	\$1,219	\$(65)	-	-	-	-	

**TABLE 19-3  
CAPITAL  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast					WP Reference	
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		2026
1		Work at the Request of Others-Rule 20A	\$31,123	\$28,255	\$32,610	\$45,758	\$38,273	\$47,288	\$39,954	\$39,876	\$40,957	\$42,060	\$43,204	WP 19-1, line 1
2		Total	\$31,123	\$28,255	\$32,610	\$45,758	\$38,273	\$47,288	\$39,954	\$39,876	\$40,957	\$42,060	\$43,204	

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 20**  
**ELECTRIC DISTRIBUTION DATA MANAGEMENT AND**  
**TECHNOLOGY**  
**[INCLUDES ERRATA THROUGH FEBRUARY 25, 2022]**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 20  
ELECTRIC DISTRIBUTION DATA MANAGEMENT AND TECHNOLOGY  
[INCLUDES ERRATA THROUGH FEBRUARY 25, 2022]

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PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 20  
ELECTRIC DISTRIBUTION DATA MANAGEMENT AND TECHNOLOGY  
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1                                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                                   **CHAPTER 20**  
3                                   **ELECTRIC DISTRIBUTION DATA MANAGEMENT AND**  
4                                   **TECHNOLOGY**  
5                                   **[INCLUDES ERRATA THROUGH FEBRUARY 25, 2022]**

6   **A. Introduction**

7       **1. Scope and Purpose**

8           The purpose of this chapter is to demonstrate that Pacific Gas and  
9           Electric Company's (PG&E or the Company) expense and capital  
10          expenditure forecasts for electric distribution data management and  
11          technology investments are reasonable and should be adopted by the  
12          California Public Utilities Commission (CPUC or Commission).

13          PG&E's Electric Operations (EO) Data Management program covers  
14          improvements to data management capabilities as well as management and  
15          maturation of core data systems, platforms, and associated business  
16          processes necessary to facilitate accurate, traceable, verifiable, complete,  
17          and accessible distribution asset information in order to enable effective  
18          data-driven decisions for asset risk management.

19          Also included in this chapter is EO's portfolio of Information Technology  
20          (IT)-related technology investments needed to improve capabilities related  
21          to asset and work management, customer service, and billing and rates.

22          PG&E is including EO Data Management and Technology investments  
23          in this chapter to align with PG&E's current EO organizational structure. In  
24          the 2020 GRC, PG&E forecasted similar types of activities in Exhibit  
25          (PG&E-4), Chapters 15 (Technology) and 18 (Data Management), although  
26          a portion of the Data Management organization is entirely new as of 2020.  
27          Currently all of Data Management and Technology are managed within EO's  
28          Asset Knowledge Management (AKM) organization.

29          The forecast in the chapter does not include: (1) technology programs  
30          that primarily support Distributed Energy Resources integration and meet  
31          the definition of Grid Modernization Plan investments from

1 Decision (D.) 18-03-023,<sup>1</sup> (2) technology work supporting wildfire  
2 mitigations,<sup>2</sup> or (3) centralized, enterprise-wide investments in data  
3 management tools or capabilities.<sup>3</sup>

## 4 **2. Summary of Request**

5 PG&E requests that the Commission adopt its 2023 expense forecast of  
6 \$26.0 million to support electric distribution-related data management and  
7 technology activities, which is \$14.4 million more than the 2020 recorded  
8 amount of \$11.7 million.<sup>4</sup> The expense forecast supports the delivery of  
9 technology projects and management of EO asset data, and includes the  
10 following types of expenditures:

- 11 • Development and implementation of PG&E's Asset Data Management  
12 Plan, data management standards, procedures, tools, analytic products,  
13 and data quality improvement projects;
- 14 • Geographic Information Systems (GIS) base mapping activities, asset  
15 data improvements, and system technical enhancements; and
- 16 • IT projects supporting Asset Management, Work Management, Billing  
17 and Rates, Customer Service, and other capabilities.

18 Additionally, PG&E requests that the CPUC adopt its capital forecast for  
19 Electric Distribution Data Management and Technology projects and  
20 programs of \$17.7 million for 2021, \$23.6 million for 2022, \$19.7 million for  
21 2023, \$18.4 million for 2024, \$18.4 million for 2025, and \$20.6 million for  
22 2026. PG&E's 2023 forecast is approximately \$3.1 million lower than 2020  
23 recorded capital expenditures of \$22.8 million.<sup>5</sup> The capital forecast  
24 primarily supports the delivery of technology projects enabling Asset

---

1 These programs are discussed in Exhibit (PG&E-4), Chapter 21, Integrated Grid Platform and Grid Modernization Plan.

2 These programs are discussed in Exhibit (PG&E-4), Chapter 4.4, Community Wildfire Safety Program Project Management Office.

3 These programs are discussed in Exhibit (PG&E-7), Chapter 7, Enterprise Records and Information Management and Enterprise Data Governance.

4 Exhibit (PG&E-4), Workpaper (WP) 20-1, line 3.

5 Exhibit (PG&E-4), WP 20-9, line 3.

1 Management, Work Management, Billing and Rates, and Customer Service  
2 capabilities.

3 The projects forecast in this chapter represent EO's expected data  
4 management and technology needs as of the time the forecast was  
5 prepared. Due to the rapid pace of technology advancements and changing  
6 business priorities, PG&E may execute the forecast projects at a different  
7 pace or pursue alternative projects.

### 8 **3. Overview of Recorded and Forecast Costs**

9 PG&E uses the MWCs shown in Table 20-1 to record and forecast data  
10 management and technology-related expenditures for expense and capital.

**TABLE 20-1**  
**ELECTRIC DISTRIBUTION DATA MANAGEMENT AND TECHNOLOGY CATEGORIES**

Line No.	MWCs	Description
1	<u>Expense MWC</u>	
2	JV	IT Expense
	GE	Electric Distribution Asset Data Management and Improvement
3	<u>Capital MWC</u>	
4	2F	IT Capital
5	21	Miscellaneous Capital

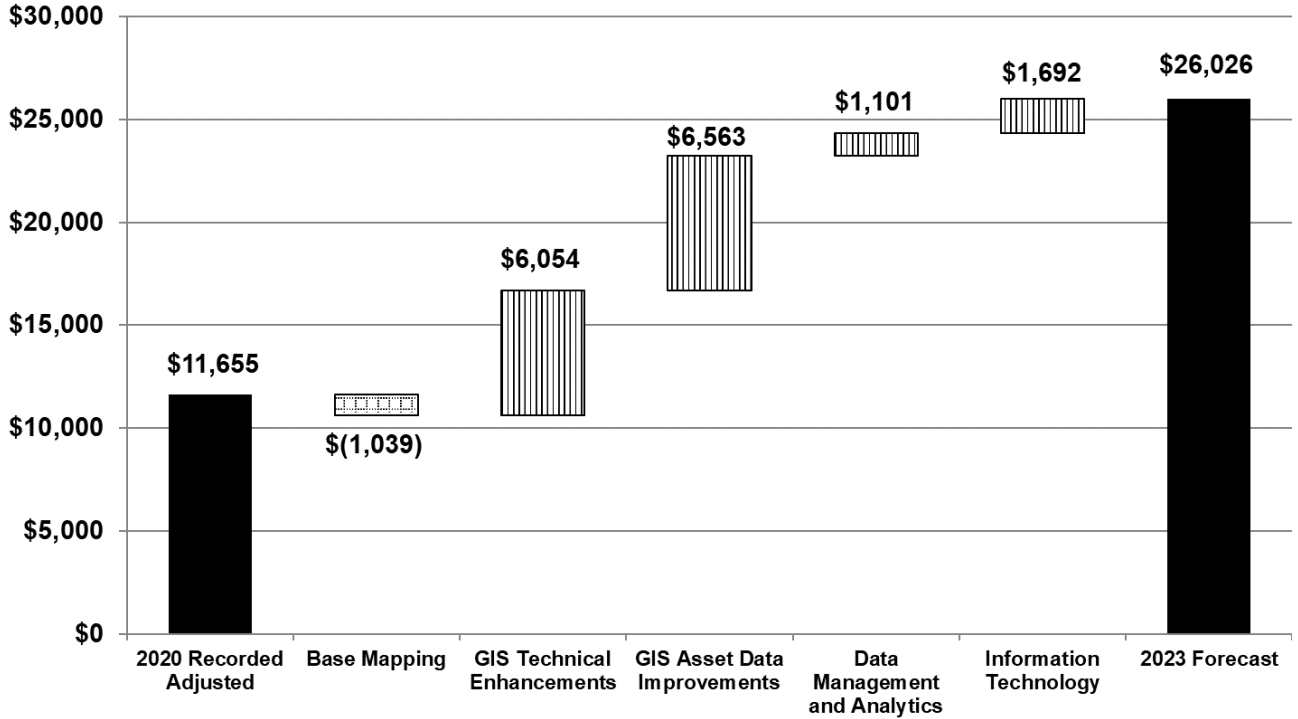
#### 11 **a. Expense**

12 Figure 20-1 shows the changes between PG&E's 2020 recorded  
13 costs and its 2023 expense forecast.<sup>6</sup> The main increases from 2020  
14 recorded amounts are primarily due to GIS asset data-related work to  
15 improve PG&E's asset registry and upgrade GIS to a Utility Network  
16 model.

---

<sup>6</sup> This figure includes costs recorded in Fire Risk Mitigation Memorandum Account (FRMMA) included for trending purposes.

**FIGURE 20-1  
EXPENSE WALK 2020-2023  
(THOUSANDS OF NOMINAL DOLLARS)**

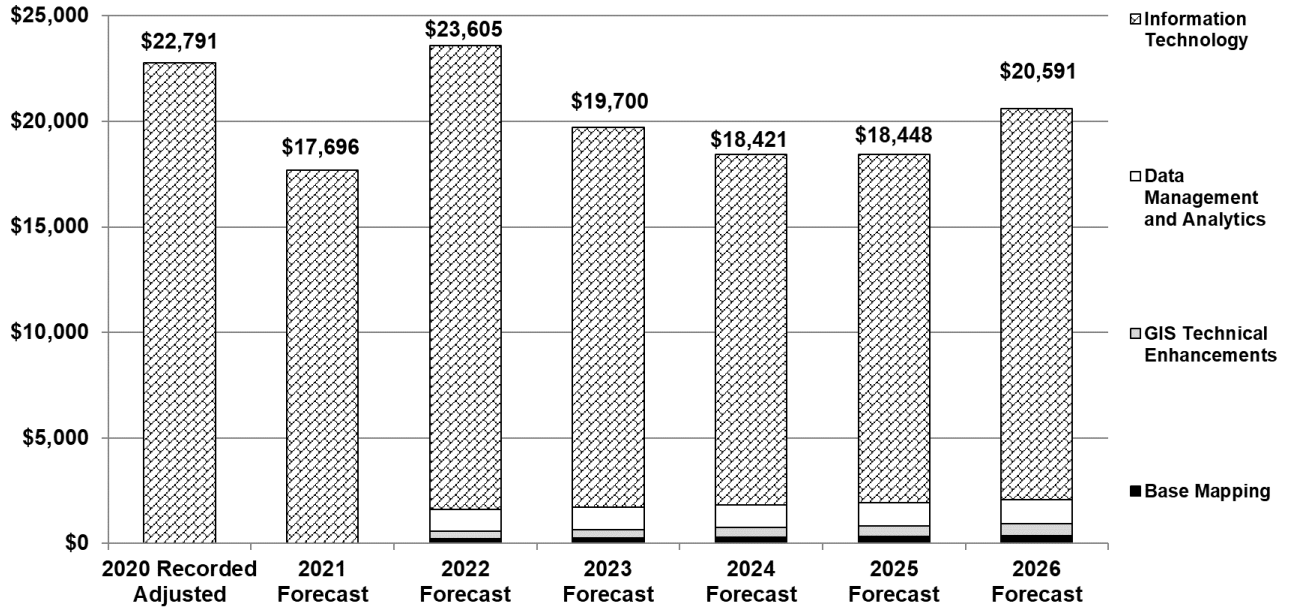


1  
2  
3  
4  
5  
6  
7

**b. Capital**

Figure 20-2 shows the capital 2020 recorded and 2021-2026 forecast expenditures by program area. The decrease from 2020 recorded to 2023 forecast is due primarily to different technology investment needs from year to year. The capital forecast supports the delivery of the same types of data management and technology initiatives as those listed above in the expense section.

**FIGURE 20-2  
CAPITAL RECORDED AND FORECAST 2020-2026  
(THOUSANDS OF NOMINAL DOLLARS)**



1        **4. Support for Request**

2                PG&E’s expense and capital expenditures for Data Management and  
3        Technology investments should be approved. To develop this forecast,  
4        PG&E has taken the following steps:

5        Data Management

- 6        • Assessed the maturity of PG&E’s current state data management capabilities using established data management maturity models;
- 7
- 8        • Identified a target state maturity for each component of data management that aligns with PG&E’s commitment in the 2020 Wildfire Mitigation Plan (WMP) to advance data management maturity to a level
- 9
- 10       of 2.5 (on a scale 0 to 4);
- 11
- 12       • Identified core investment areas and estimated the level of maturity needed to achieve its target state data management maturity;
- 13
- 14       • Followed a collaborative, integrated planning approach with the Enterprise data management and IT teams to promote alignment;
- 15
- 16       • Collaborated with electric asset family owners and process owners to identify critical asset data enhancements to support their business to
- 17

1 effectively manage the inherit risk associated with electric utility  
2 operations; and

- 3 • Identified client needs and enhancements to operate an efficient GIS  
4 system in both viewing and editing products leveraging industry best  
5 practices to transition to a programmatic approach and Utility Network  
6 model.

### 7 Technology

- 8 • Identified key technology programs that support EO goals and  
9 objectives;
- 10 • Followed a collaborative and rigorous integrated planning and road  
11 mapping process to identify and prioritize technology investments; and
- 12 • Used a sound basis to develop the technology project portfolio scope  
13 and approach, timing, and cost estimates, in addition to identifying both  
14 quantitative and qualitative benefits.

## 15 **5. Organization of the Remainder of This Chapter**

16 The remainder of this chapter is organized as follows:

- 17 • Section B – Program and Risk Overview
- 18 • Section C – Activities, Costs, and Forecast Drivers
- 19 • Section D – Estimating Methods
- 20 • Section E – Compliance with Section 5.2 of the 2020 GRC Settlement  
21 Agreement (“Deferred Work Principles”)
- 22 • Section F – Cost Tables

## 23 **B. Program and Risk Overview**

### 24 **1. Program Description**

#### 25 **a. Program Overview**

26 The work represented in this chapter in the areas of EO Data  
27 Management and Technology investments is implemented by PG&E’s  
28 Electric AKM organization. The mission of AKM is to support EO’s  
29 ability to make data-driven decisions by improving the accessibility,  
30 quality, and use of information, maturing analytical capabilities, and  
31 deploying analytical and operational products and technologies.

## 1           **b. Management Structure**

2           The AKM management structure includes strategic and  
3           programmatic leadership of four EO programs:

- 4           • DM&A – Includes implementation of EO’s information asset  
5           management program (Publicly Available Specification 55 (PAS  
6           55)/ISO 55001), Enterprise data management standards, and EO’s  
7           Foundry data platform;
- 8           • GIS Asset Data Management – Includes transmission and  
9           distribution GIS system data maintenance and improvement, user  
10          tools, and system performance;
- 11          • Technology Portfolio Management – Aligns with the IT portfolio  
12          including program strategy, IT work prioritization, and in-flight project  
13          management office; and
- 14          • Emerging Technology Program – Electric Program Investment  
15          Charge and Wildfire Mitigation emerging tech programs including  
16          portfolio management (e.g., strategy, governance, enablement),  
17          technology benchmarking, regulatory engagement, and in-flight  
18          project management office. Emerging Technology costs are  
19          forecast in Chapter 21, Integrated Grid Platform and Grid  
20          Modernization Plan.

## 21           **c. Key Metrics and Other Performance Measures**

22           The AKM organization is driving improvements in asset data to  
23           enable capabilities and services for wildfire mitigation and safety and to  
24           achieve external commitments such as PAS55 certification. Some key  
25           metrics the organization uses to operate effectively include the record  
26           duration index, measuring the cycle time it takes for As-Built information  
27           to be entered into the system of record. In addition, the volume of active  
28           map corrections is tracked to assess asset information risk which is  
29           managed accordingly.

## 30           **2. Risk Integration**

31           Risk controls and mitigations are aligned to various MWCs and  
32           Maintenance Activity Types in Electric Distribution. None of the MWCs

1 presented in this chapter directly correspond to a risk mitigation or risk  
2 control that address a risk on EO's Corporate Risk Register. More  
3 information about risk mitigations and controls is in PG&E's Electric  
4 Distribution Risk Management testimony (Exhibit (PG&E-4), Chapter 3).

## 5 **C. Activities, Costs, and Forecast Drivers**

### 6 **1. Data Management (MWCs GE, 21)**

7 MWCs GE<sup>7</sup> and 21 track two EO data management workstreams:  
8 (1) DM&A, and (2) GIS Asset Data Management. These workstreams,  
9 described in greater detail below, include the maturation of capabilities and  
10 management of core data quality and systems/platforms (e.g., GIS, SAP AG  
11 Software (SAP), Foundry) to provide asset information that is accurate,  
12 traceable, verifiable, and complete and to enable effective data-driven  
13 decisions for asset and risk management.

14 PG&E's 2023 expense forecast for these activities in MWC GE is  
15 \$21.5 million, which is \$12.7 million more than its 2020 recorded costs of  
16 \$8.8 million.<sup>8</sup> The primary drivers for this increase are activities associated  
17 with the new DM&A organization as well as the NextGen GIS effort  
18 described below.

19 PG&E's capital forecast for these activities in MWC 21 is \$0 in 2021,  
20 \$1.6 million in 2022, \$2.0 million in 2023, \$2.4 million in 2024, \$2.9 million in  
21 2025, and \$3.6 million in 2026.<sup>9</sup> There are no 2020 recorded costs in MWC  
22 21 for Data Management. The primary driver for the forecast is the  
23 development of the Foundry data platform.

#### 24 **a. Data Management and Analytics**

25 PG&E is forecasting \$5.2 million expense in 2023, and capital  
26 expenditures forecasts of \$0 in 2021, \$1.0 million in 2022, \$1.1 million in

---

7 In the 2020 GRC, MWC GE included forecasts for Electric Distribution Mapping and the Field Asset Inventory (FAI) project. The work under MWC GE is expanding in the 2023 GRC to reflect PG&E's heightened focus on asset data management activities beyond mapping.

8 Exhibit (PG&E-4), WP 20-1, line 1.

9 Exhibit (PG&E-4), WP 20-9, line 1.

1 2023, \$1.1 million in 2024, \$1.1 million in 2025, and \$1.1 million in 2026  
2 to support EO DM&A activities. This is an increase of \$1.1 million  
3 expense and \$1.1 million capital compared to 2020 recorded  
4 expenditures.<sup>10</sup>

5 In 2020 PG&E established a data management organization at the  
6 enterprise level, with a Director of Data Governance. The Enterprise  
7 data management organization is responsible for developing enterprise  
8 level data strategy, policies, standards, and objectives. In parallel, EO  
9 developed a DM&A organization to guide electric data strategy, data  
10 quality, and data management efforts, including implementation of  
11 Enterprise Data Governance and Standards. The DM&A organization  
12 establishes overall priorities, standards, and processes to manage data  
13 critical to EO's Asset Risk Management. Implementation of the electric  
14 data strategy will be led by the DM&A organization in partnership with  
15 the Enterprise data management team, IT business partners, and EO  
16 business units. Centralization of the data management function helps  
17 align data strategies across EO and the enterprise and improves  
18 PG&E's ability to make data-driven decisions around asset-related risk  
19 management.

20 Activities that the DM&A organization plans to pursue during the  
21 2021-2026 period include:

- 22 • Implementation of Asset Data Asset Management Plan (AMP): This  
23 is an umbrella initiative guiding the application of best practices for  
24 asset management and data, including understanding and  
25 managing the inventory of critical data assets, the condition of the  
26 data including its quality and the risks associated with the data, and  
27 designing/implementing programs, standards, and processes to  
28 optimize the performance of data assets;
- 29 • Implementation of Data Management Standards, Processes, and  
30 Tools: The implementation of data management standards,  
31 processes, and tools are intended to systematically detect and

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<sup>10</sup> Exhibit (PG&E-4), WP 20-7, line 5 and WP 20-18, line 3.

1 remediate data quality issues. PG&E will improve data quality  
2 through creation and implementation of data quality rules in its data  
3 platform and key source systems. PG&E will also identify at-risk  
4 data assets that require remediation and design and implement  
5 solutions to improve data quality; and

- 6 • Implementation of Data Platform: In order to effectively manage  
7 assets and asset risk, PG&E must bring together physical,  
8 operational, lifecycle, and environmental data elements from  
9 existing disparate purpose-built data systems into a single  
10 environment to better enable access to data in support of asset  
11 planning, risk management, and operations, and embedded data  
12 analytics for ad hoc analyses. To this end, a core element of  
13 PG&E's enterprise data management strategy is an enterprise data  
14 platform – Palantir Foundry – that will allow PG&E to establish key  
15 connections between disparate data sets.

16 Recorded and forecast amounts in MWC GE also include  
17 \$3.0 million recorded in 2020 and \$1.8 million forecast in 2021 to  
18 support data management activities related to wildfire mitigation,  
19 recorded in the FRMMA, and included in the amounts in Table 20-2  
20 below.<sup>14</sup> This work is driven by PG&E's AMP and addresses the  
21 following AMP items:

- 22 • AMP 6: Publish EO Asset Information Framework that defines the  
23 critical physical, operational, lifecycle and environmental data  
24 elements that are required for risk-informed, data driven  
25 decision-making; and
- 26 • AMP 12: Publish a data model for use in the development of EO  
27 asset risk models.

28 PG&E does not have a forecast for this work for the 2022-2023  
29 period. If additional work is needed 2021, PG&E will continue to record  
30 costs in the FRMMA.

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<sup>14</sup> See Exhibit (PG&E-4), Chapter 2, Attachment A, Table 2A-3.

1                    Tables 20-2 and 20-3 below summarize PG&E's forecasts for Data  
2                    Management and Analytics.

**TABLE 20-2  
DATA MANAGEMENT AND ANALYTICS  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Expense (MWC GE)	-	-	\$100	\$100	\$4,152	\$6,500	\$4,723	\$5,253	WP 20-7, line 5.

**TABLE 20-3  
DATA MANAGEMENT AND ANALYTICS  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	Capital (MWC 21)	-	-	-	-	-	-	\$1,026	\$1,054	\$1,082	\$1,111	\$1,141	WP 20-18, line 3.

1           **b. GIS Asset Data Management**

2           PG&E is forecasting \$16.3 million expense<sup>12</sup> and capital forecasts of  
3           \$0.7 million<sup>13</sup> in 2023, \$0.7 million in 2024, \$0.8 million in 2025, and \$0.9 million in  
4           2026 to support EO GIS Asset Data Management activities. This forecast includes  
5           work in three main asset data functions: Base Mapping, GIS Technical  
6           Enhancements, and GIS Asset Data Improvements. This is an increase of  
7           \$11.6 million expense and \$0.7 million recorded capital in 2020. This increase is  
8           primarily driven by the implementation of PG&E's NextGen GIS project beginning in  
9           2023, as well as an increased number of updates to the asset registry stemming  
10          from PG&E's implementation of enhanced inspections.

11          EO's Asset Data Management activities maintain and deliver the asset registry  
12          foundation for the AMP. The GIS Asset Data Management organization is  
13          responsible for establishing electric asset data as a trusted data source that clients  
14          can use to make informed decisions and work effectively and efficiently through a  
15          reliable GIS system. The program maintains and improves asset data features and  
16          attributes, including age, environmental data, and asset location, in order to develop  
17          a traceable, verifiable, and complete GIS asset data registry. Asset Data  
18          Management activities are further described below.

19          **1) Base Mapping**

20          PG&E's expense forecast for Base Mapping is \$0.4 million in 2023.<sup>14</sup>  
21          PG&E's capital expenditures forecast for Base Mapping is \$0 in 2021,  
22          \$0.2 million in 2022, \$0.3 million in 2023 \$0.3 million in 2024, \$0.3 million in  
23          2025 and \$0.4 million in 2026.<sup>15</sup> PG&E's 2023 forecasts for this activity are  
24          \$1.4 million lower than PG&E's 2020 recorded expense and \$0.3 million higher  
25          than 2020 recorded capital. The decrease in expense is primarily due to asset  
26          registry update costs stemming from PG&E's implementation of enhanced  
27          inspections being forecast in the GIS Asset Data Improvement function rather  
28          than here.

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12 Exhibit (PG&E-4), WP 20-7, lines 2-4.

13 Exhibit (PG&E-4), WP 20-18, lines 1-2.

14 Exhibit (PG&E-4), WP 20-7, line 2.

15 Exhibit (PG&E-4), WP 20-18, line 1.

1           Base mapping work is comprised of general mapping activities that  
2 maintain electric distribution maps and asset-related records, providing timely  
3 traceable, verifiable, complete, and accurate data and spatial information for  
4 PG&E's electric system. PG&E's GIS Mappers are responsible for updating  
5 targeted GIS information whenever facilities in the field are installed, replaced,  
6 or retired. Mappers also correct GIS information on maps as needed based on  
7 information received from field personnel. Base mapping also includes funding  
8 for the Mapping Advancement Program (MAP), a comprehensive self-directed  
9 training program that provides the knowledge and skills necessary to perform  
10 the responsibilities of the Mapping Technician classification.

11           Tables 20-4 and 20-5 below summarize PG&E's forecasts for Base  
12 Mapping.

**TABLE 20-4  
BASE MAPPING  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Expense (MWC GE)	\$2,174	\$1,666	\$949	\$536	\$1,430	\$1,640	\$1,640	\$391	WP 20-7, line 2.

**TABLE 20-5  
BASE MAPPING  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	Capital (MWC 21)	-	-	\$10	\$18	\$3	-	\$233	\$263	\$297	\$335	\$378	WP 20-18, line 1.

## 2) GIS Technical Enhancements

GIS Technical Enhancements are ongoing enhancements to improve the overall performance of PG&E's GIS systems. The enhancements help to enhance risk informed data-driven decisions around critical assets as well as to meet compliance requirements and provide downstream systems with the data necessary for any regulatory requirement.

PG&E's expense forecast for GIS Technical Enhancements is \$6.8 million in 2023.<sup>16</sup> PG&E capital expenditures forecast for GIS Technical Enhancements is \$0 in 2021, \$0.3 million in 2022, \$0.4 million in 2023, \$0.4 million in 2024, \$0.5 million in 2025, and \$0.6 million in 2026.<sup>17</sup> PG&E's 2023 forecasts are \$6.1 million more than 2020 recorded expense and \$0.4 more than 2020 recorded capital.

The primary driver of the GIS Technical Enhancement forecast is the anticipated need for a NextGen GIS effort beginning in 2023 and lasting through 2026. The GIS platform used by PG&E for all mapping activities will only be supported by the product developer (Environmental Systems Research Institute) until March 2026. After that point, customers will need to migrate to a replacement product (ArcGIS Pro) which uses the Utility Network data model, a more utility-specific data model than the Geometric Network data model used by PG&E's existing GIS platform. The migration to the Utility Network data model will support asset risk reductions and improve system operations and reliability given its enhanced integration with the Advanced Distribution Management System, asset risk modeling, and other critical systems. It will also improve efficiencies and customer experience through the bundling of the currently independent Electric Distribution and Electric Transmission Geographic Information Systems, connections to graphic work

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<sup>16</sup> Exhibit (PG&E-4), WP 20-7, line 3.

<sup>17</sup> Exhibit (PG&E-4), WP 20-18, line 2.

1 designs, and As-Built information quality and expediency through  
2 mobile solutions.

3 ArcGIS Pro will provide a comprehensive framework for  
4 modeling utility systems. It is designed to model all the components  
5 that make up the system and allows users to build real-world  
6 behaviors into the features of the model. This model is simpler and  
7 more scalable than the model currently used by PG&E and brings  
8 native capabilities into ArcGIS that were once only offered by third  
9 parties.

10 To complete the GIS re-platform, PG&E plans to:

- 11 • Select a system integrator that knows the Utility Network data  
12 model and has migration experience;
- 13 • Perform data analysis and curation on existing GIS datasets to  
14 prepare for data migration;
- 15 • Enable a means for Geometric Network and Utility Network data  
16 model-based systems to run in parallel while migrations  
17 occur. Other alternatives include dual mapping efforts during  
18 the migration period;
- 19 • Migrate data, editing tools, and existing applications and  
20 interfaces that are currently dependent on the Geometric  
21 Network data model into the Utility Network data model; and
- 22 • Provide change management to manage downstream impacts  
23 of the change in data models.

24 PG&E is also forecasting additional GIS system enhancements  
25 and analytics tools outside of the NextGen GIS effort in order to  
26 improve GIS data quality and provide support to a variety of  
27 business clients for risk management, system operations, and  
28 customer experience improvements. These enhancements include:

- 29 • Data Quality Dashboards: Dashboards provide the ability to  
30 measure asset data quality in GIS against seven data quality  
31 dimensions – completeness, conformity, consistency,  
32 uniqueness, timeliness, synchronization, and accuracy.

33 Introducing ED-GIS data into Palantir Foundry data tools will

1 enable building data dashboards and performing historical  
2 analysis.

- 3 • Graphic Work Design: Graphic Work Design (GWD) involves  
4 software tools that enable automated creation of GIS data from  
5 Computer-Aided Design tools where engineering relationships  
6 between components and subcomponents exist. Lists of  
7 components and subcomponents approved for PG&E's use are  
8 maintained in SAP and integrated by GWD engineering.  
9 Integration with GIS provides accurate placement of existing  
10 assets and eliminates re-drawing during the asset design  
11 process. Original design and design changes through As-Builts  
12 are also integrated, with GIS eliminating mapping from paper  
13 drawings.
- 14 • Asset Data Management & Improvement (ADM&I) Work Plans,  
15 Schedules, and Metrics: This involves configuring ADM&I, work  
16 plans, data extrapolations, new data designs, and data testing  
17 from SAP to support a risk-based prioritization to manage GIS  
18 ADM&I work schedules, as well as development and  
19 maintenance of automated and centralized visualization tools  
20 that measure critical work activities for effective and efficient  
21 quality outcomes.
- 22 • GIS Analytics Tools: GIS Analytics tools include the capital  
23 costs needed to support the GIS team, including advanced  
24 software, servers, and hardware, such as high-end laptops,  
25 desktop CPUs etc. to deliver time-sensitive solutions for  
26 Meteorology and PSPS teams during emergency operations.  
27 GIS team initiatives provide support to a variety of business  
28 clients for risk management, system operations, and customer  
29 experience improvements. GIS team solutions deliver spatially  
30 enabled views into PG&E's asset datasets.

31 Tables 20-6 and 20-7 below summarize PG&E's forecasts for  
32 GIS Technical Enhancements.

**TABLE 20-6  
GIS TECHNICAL ENHANCEMENTS  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Expense (MWC GE)	-	-	-	\$36	\$711	\$900	\$900	\$6,765	WP 20-7, line 3.

**TABLE 20-7  
GIS TECHNICAL ENHANCEMENTS  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	Capital (MWC 21)	-	-	-	-	-	-	\$349	\$395	\$445	\$502	\$566	WP 20-18, line 2.

### 3) GIS Asset Data Improvements

PG&E is forecasting \$9.1 million expense in 2023 to support EO GIS Asset Data Improvement activities. This is an increase of \$6.5 million from 2020 recorded expense.<sup>18</sup> This increase in anticipated spend corresponds with the increased scope of PG&E's Enhanced Inspection Plan, as well as a switch from a circuit to a structure asset base approach. This change is expected to result in the need for additional updates to the asset registry in the areas described below.

GIS Asset Data Improvements support the accuracy and completeness of asset information, maps, and records in the integrated Electric Distribution GIS. These improvements are necessary to maintain the accuracy of PG&E's asset data, including date of installation, manufacturer, and model number. This asset information is vital to identifying which assets need to be replaced and when. In the event of a repair, accurate asset data helps crews know what equipment to take to the job site.

PG&E previously forecast work with a similar objective to the GIS Asset Data Improvement program in the 2020 GRC under the name Field Asset Inventory (FAI). FAI was a project intended to deliver a complete field inventory of the electric distribution overhead system and manually correct asset data discrepancies between PG&E's actual assets in the field and asset records in the SAP and ED-GIS databases. Ultimately the FAI project was deferred due to contractor concerns and budgeting constraints.

PG&E is now attempting to achieve the goals of the FAI project in a different way, by conflating electric distribution overhead support structures to their correct geographic location leveraging remote sensing and GPS technology as opposed to a manual FAI. This work is ongoing and will continue through the GRC period. In addition, the increased scope of PG&E's Enhanced Inspection Plan

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<sup>18</sup> Exhibit (PG&E-4), WP 20-7, line 4.

1 has driven a need for four additional asset data improvement efforts  
2 which PG&E is forecasting in this GRC. Each effort will add to  
3 available asset information and correct discrepancies between  
4 actual assets in the field and PG&E's asset registry. The first effort  
5 will update GIS records and databases from a system-wide  
6 streetlight inventory while ensuring that the systems of record  
7 remain in sync. The second effort will consist of an inventory of  
8 underground electric distribution facilities in the Bay Area region to  
9 improve GIS asset data associated with those facilities. The third  
10 effort is to address an increase in Request for Work (RW) map  
11 corrections. Tracking and completion of RW map corrections is  
12 critical to having a complete, accurate, traceable, and verifiable  
13 asset register. Corrections need to be validated in the SAP  
14 database to ensure complete alignment between GIS and SAP,  
15 since SAP information is used for maintenance plans including  
16 system inspections. The last project is to develop, implement, and  
17 maintain critical features and attributes in GIS for quantitative risk  
18 management decisions. As asset risk models mature, the need for  
19 a more detailed understanding of asset characteristics at an  
20 electrical component level will increase driving the need for a more  
21 comprehensive asset data collections and upkeep.

22 Table 20-8 below summarizes PG&E's forecast for GIS Asset  
23 Data Improvements.

TABLE 20-8  
GIS ASSET DATA IMPROVEMENT  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Expense (MWC GE)	\$652	\$583	\$3,277	(\$496)	\$2,552	\$8,991	\$8,991	\$9,115	WP 20-7, line 4.

## 2. Technology Portfolio Management (MWC JV, 2F)

PG&E's IT organization has begun to adopt an IT industry framework for delivering technology investments using Agile and Lean principles. Within this framework, called the Scaled Agile Framework, technology investments are planned, organized, and managed through logical constructs called Value Streams. A Value Stream, in essence, represents an ongoing program of technology investments that support aspects of Company operations where technology solutions are of long-term strategic importance. Within a Value Stream, PG&E will continually plan, prioritize, and sequence specific investments based on the value they provide to the associated aspect of Company operations at a given time. Not only does this help ensure consistent investment in critical business and technology capabilities, it also enables specialized, cross-functional delivery teams to adapt more nimbly to emergent customer and business needs, changes in priority or value propositions, and innovation in the technology environment.

For more information about PG&E's IT Value Stream approach, see Exhibit (PG&E-7), Chapter 8, Section C.3.

PG&E's 2023 expense forecast for MWC JV is \$4.5 million, which is \$1.7 million more than the 2020 recorded costs of \$2.8 million.<sup>19</sup> PG&E's capital expenditure forecast for MWC 2F is \$18.0 million in 2023, \$16.6 million in 2024, \$16.5 million in 2025, and \$18.5 million in 2026. The 2023 capital forecast is \$4.8 million less than its 2020 recorded costs of \$22.8 million.<sup>20</sup> MWCs JV and 2F comprise a substantial number of individual IT projects in any given year with some projects reaching completion, some in-flight, and additional projects launching. The drivers for the overall change between the 2020 recorded costs and the 2023 forecast costs are best discussed in terms of the changes occurring in individual Value Streams, and are presented in Sections 2.a–2.e below.

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<sup>19</sup> Exhibit (PG&E-4), WP 20-1, line 2.

<sup>20</sup> Exhibit (PG&E-4), WP 20-17, line 12.

1           **a. Asset Management and Risk Analysis**

2           PG&E is forecasting \$0.4 million expense and capital forecasts of  
3           \$2.8 million in 2023, \$3.7 million in 2024, \$3.0 million in 2025, and  
4           \$3.3 million in 2026 to support Asset Management and Risk Analysis  
5           technology investments. This is a decrease of \$1.1 million expense and  
6           \$4.7 million capital from 2020 recorded.<sup>21</sup> This decrease is primarily  
7           driven by completion of the Meter Set Technology Upgrade and  
8           ED-GIS-related projects, partially offset by the new technology  
9           investments described below.

10           Asset Management and Risk Analysis technology investments are  
11           focused on improving the understanding and management of electric  
12           asset conditions and risks. The work is centered on the development of  
13           high-quality asset data systems that process and integrate key data in  
14           real or near-real time to provide asset lifecycle stakeholders with  
15           seamless access to accurate, trustworthy, up-to-date data. The Asset  
16           Management and Risk Analysis technology investment forecast in this  
17           chapter supports development of the following capabilities:<sup>22</sup>

- 18           1) Asset data integrity is supported by ensuring that all EO asset  
19           classes are managed through a common asset management  
20           platform. Work supported by the forecast in this chapter includes  
21           establishing additional asset classes in PG&E's SAP asset  
22           management system. An example is the creation of an asset  
23           registry for streetlights;
- 24           2) Developing holistic asset management risk models that will support  
25           analysis of risk from multiple risk conditions, including the risk of  
26           wildfire ignition and storm damage. A central driver of this work has  
27           been to develop electric predictive asset maintenance models based

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**21** Exhibit (PG&E-4), WP 20-8, line 2 and WP 20-17, line 2.

**22** In addition to the Asset Management and Risk Analysis activities forecast in this chapter, the Value Stream includes IT technology investments that support EO's Wildfire risk mitigation activities. The forecast for wildfire risk-related investments is described in Chapter 4 of this exhibit.

1                   on a real-time understanding of operating conditions, asset health,  
2                   and risk; and

3                   3) Streamlining the sharing of key asset data. An example is the  
4                   sharing of pole loading data with other utilities and key third parties  
5                   through a central database which helps support grid safety by  
6                   preventing the incorrect physical loading of poles used jointly.

7                   Tables 20-9 and 20-10 summarize PG&E's Asset Management and  
8                   Risk Analysis technology forecast.

**TABLE 20-9  
AM AND RISK ANALYSIS  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Expense (MWC JV)	\$445	\$1,144	\$605	\$618	\$1,455	\$444	\$420	\$372	WP 20-1 line 2.

**TABLE 20-10  
AM AND RISK ANALYSIS  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	Capital (MWC 2F)	\$4,163	\$9,034	\$4,450	\$803	\$7,576	\$1,890	\$4,602	\$2,819	\$3,682	\$3,049	\$3,275	WP 20-17 line 2.

1           **b. Field Work Management**

2           PG&E is forecasting \$2.3 million expense and capital forecasts of  
3           \$9.0 million 2023, \$5.5 million in 2024, \$5.4 million in 2025, and  
4           \$5.6 million in 2026 to support Field Work Management technology  
5           investments. This is an increase of \$2.2 million expense and  
6           \$3.9 million capital from 2020 recorded.<sup>23</sup> The main driver of this  
7           increased investment is expanded digitization of design and estimating  
8           toolsets and the development of software tools for new service  
9           application work-planning and scheduling.

10          The Field Work Management technology investments focus on  
11          technology solutions used to plan and execute field work safely and  
12          efficiently, to document performed work completely and accurately, and  
13          to manage the flow of information between field crews and the  
14          back-office. At the enterprise level, a major goal of PG&E's Field Work  
15          Management technology investments is to implement a cross-LOB  
16          technology solution comprised of integrated mobile and web-based  
17          software systems that enable digitization and standardization of utility  
18          work processes from initiation to completion, as is discussed more fully  
19          in Exhibit (PG&E-7), Chapter 8.

20          The Field Work Management technology forecast in this chapter is  
21          for investments by EO that facilitate and augment the enterprise-level  
22          solutions discussed in Exhibit (PG&E-7), Chapter 8. The business  
23          technology investments forecast for this rate cycle include development  
24          of the following business capabilities:

- 25          1) Upgrading design and estimating toolsets with a modern, integrated  
26             and graphics-based construction design software. This will support  
27             improved design and construction consistency and efficiency,  
28             incorporating factors such as standards, optimal design, and  
29             material usage cost-effectiveness;
- 30          2) Development of workflow tools targeted to organizing and  
31             coordinating the work for customer Electric Generation

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<sup>23</sup> Exhibit (PG&E-4), WP 20-8, line 8 and WP 20-17, line 8.

1 Interconnection (EGI) applications. The need for such tools  
2 continues to grow as the number of clean energy grid  
3 interconnection applications continues to grow, and the engineering  
4 coordination needed to facilitate that these interconnections satisfy  
5 grid design stability requirements also increases; and  
6 3) Development of additional tools to enhance work management  
7 capabilities, including automation of substation recordkeeping to  
8 promote consistent asset health information is captured in the same  
9 tool from installation to decommission. PG&E is also continuing to  
10 develop digital tools to enable better tracking and coordination of  
11 shared assets such as poles jointly used with other vendors (AT&T,  
12 Comcast, and other utilities). These investments enhance grid  
13 safety, for example by reducing the risks of pole overloading, which  
14 can result in unanticipated pole failures.  
15 Tables 20-11 and 20-12 summarize PG&E's Field Work  
16 Management technology forecast.

**TABLE 20-11  
FIELD WORK MANAGEMENT  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Expense (MWC JV)	\$720	\$1,710	\$1,928	\$224	\$132	\$785	\$1,158	\$2,267	WP 20-8 Line 8

**TABLE 20-12  
FIELD WORK MANAGEMENT  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	Capital (MWC 2F)	\$6,990	\$4,094	\$2,534	\$466	\$5,128	\$1,913	\$4,601	\$8,990	\$5,512	\$5,416	\$5,637	WP 20-17, line 8.

1           **c. Billing and Rates**

2           PG&E is forecasting \$0.1 million expense and expense forecasts of  
3           \$5.3 million 2023, \$6.4 million in 2024, \$6.1 million in 2025, and  
4           \$6.5 million in 2026 to support Billing and Rates technology  
5           investments. These investment levels represent an essentially flat  
6           expense spending level and a \$0.3 million capital increase from 2020  
7           recorded.<sup>24</sup>

8           Billing & Rates technology investments in this section focus on the  
9           technology solutions used to manage electric rates, to track customer  
10          energy usage, to generate customer bills, and to process customer  
11          financial transactions and billing exceptions.

12          The primary Billing and Rates investment during this GRC period is  
13          the EGI Tariff program, which supports the EGI process. This program  
14          automates workflow and interfaces to manage interconnection requests  
15          under PG&E's Rule 21, Wholesale Distribution Tariff. The EGI Tariff  
16          program is critical to PG&E because it ensures changes mandated by  
17          the CPUC to the EGI process are implemented within PG&E's  
18          supporting IT infrastructure in compliance with ordered deadlines.  
19          Automated processing of customer load and interconnection requests  
20          would not be possible without this program. PG&E anticipates that the  
21          evolving interconnection landscape will continue to result in numerous  
22          mandated changes.

23          Tables 20-13 and 20-14 summarize PG&E's Billing and Rates  
24          technology forecast.

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<sup>24</sup> Exhibit (PG&E-4), WP 20-8, line 3 and WP 20-17, line 3.

**TABLE 20-13  
BILLING AND RATES  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Expense (MWC JV)	\$123	\$442	\$243	\$1	\$69	\$44	\$100	\$100	WP 20-8, line 3.

**TABLE 20-14  
BILLING AND RATES  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	Capital (MWC 2F)	\$4,870	\$3,342	\$2,858	\$2,267	\$5,046	\$4,719	\$7,264	\$5,347	\$6,403	\$6,055	\$6,514	WP 20-17, line 3.

1           **d. Customer Service**

2           PG&E is forecasting \$0.1 million expense and capital forecasts of  
3           \$0.8 million 2023, \$1.0 million in 2024, \$2.0 million in 2025, and  
4           \$3.1 million in 2026 to support Customer Service technology  
5           investments. This is an increase of \$0.1 million expense and a  
6           decrease of \$2.9 million capital from 2020 recorded.<sup>25</sup>

7           The main driver of this forecast decrease is completion of the Smart  
8           Connect new service customer application portal, which is partially offset  
9           by the new technology investments described below.

10          Customer Service technology investments are intended to improve  
11          PG&E's customer service and experience by improving the application  
12          process and reducing application cycle times.

13          During the 2023-2026 rate cycle, PG&E plans to facilitate the new  
14          service application process by enabling applicant designers and their  
15          respective firms to gain limited but appropriate external access to  
16          internal PG&E estimating software so that they can directly input  
17          application data. The resulting customer-generated estimates will then  
18          be integrated into the standard PG&E workflow to help reduce  
19          duplication of effort and reduce service application times. In addition,  
20          PG&E plans to develop pre-application tools that provide customers with  
21          quick-turnaround assessments of project costs and benefits which will  
22          enable customers to decide if they want to proceed with their projects  
23          without first having to commit to the more rigorous, costly, and lengthy  
24          full application process.

25          As California moves to achieve its ambitious decarbonization goals,  
26          existing customers will need to make informed decisions about  
27          building-electrification conversions. PG&E's Service Planning group will  
28          need new tools to be able to efficiently respond to the growing number  
29          of customer requests. To help meet this need, PG&E plans to develop  
30          additional tools, including: (1) a dynamic customer-facing  
31          communications portal with integrated customer touch points to

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<sup>25</sup> Exhibit (PG&E-4), WP 20-8, line 4 and WP 20-17, line 4.

1 streamline and simplify service applications; and (2) a single  
2 Compliance and Risk Management portal that provides an integrated  
3 and complete customer view tailored to multiple stakeholders.

4 Table 20-15 and 20-16 summarize PG&E's Customer Service  
5 technology forecast.

**TABLE 20-15  
CUSTOMER SERVICE  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Expense (MWC JV)	-	\$254	\$272	\$153	\$0	\$273	\$199	\$120	WP 20-8, line 4.

**TABLE 20-16  
CUSTOMER SERVICE  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	Capital (MWC 2F)	-	\$604	\$1,979	\$541	\$3,679	\$8,942	\$5,530	\$831	\$1,000	\$1,980	\$3,080	WP 20-17, line 4.

1           **e. Safety, Governance, Regulatory, and Compliance**

2                     PG&E is forecasting \$0.9 million expense to support EO Safety,  
3                     Governance, Regulatory, and Compliance technology investments.  
4                     PG&E did not record any spending in this Value Stream in 2020. The  
5                     spending increase in 2023 relative to 2020 is associated with  
6                     maintaining the EO Mobile and Offline Document Viewer, which  
7                     provides EO field personnel with access to PG&E's Technical  
8                     Information Library while they are offline and using mobile devices.

9                     Safety, Governance, Regulatory, and Compliance technology  
10                    investments focus on the technology solutions used: to manage  
11                    workforce health and safety; to manage public safety and environmental  
12                    impacts; to manage Company records, compliance, and corrective  
13                    action programs; to support regulatory and legal proceedings; and to  
14                    manage relationships with external stakeholders.

15                    Table 20-17 summarizes PG&E's Safety, Governance, Regulatory,  
16                    and Compliance technology forecast.

**TABLE 20-17**  
**SAFETY, GOVERNANCE, REGULATORY, AND COMPLIANCE**  
**RECORDED AND FORECAST COSTS**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Expense (MWC JV)	-	\$441	\$654	\$36	-	\$1,084	\$756	\$941	WP 20-8, line 10.

1           **f. Non-Project Application Enhancements (NPAE)**

2                     PG&E is forecasting \$0.7 million expense in 2023 to support  
3                     investments in NPAEs. This is an increase of \$0.1 million expense and  
4                     \$0.6 million capital from 2020 recorded.<sup>26</sup>

5                     NPAEs modify or improve the way existing applications function.  
6                     This work supports system configuration changes to enable technology  
7                     that continues to support related business processes and aligns  
8                     business capabilities with business needs.

9                     Table 20-18 summarizes PG&E's NPAE technology forecast.

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<sup>26</sup> Exhibit (PG&E-4), WP 20-8, line 9 and WP 20-17, line 9.

TABLE 20-18  
NP&E  
RECORDED AND FORECAST COSTS  
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Cost	2016 Recorded	2017 Recorded	2018 Recorded	2019 Recorded	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Expense (MWC JV)	\$806	\$349	\$790	\$413	\$669	\$700	\$700	\$701	WP 20-8, line 9.

## 1 **D. Estimating Methods**

2 The estimating methodology used to develop the GRC forecast for this  
3 chapter was dependent on the type of work being performed. For the vast  
4 majority of IT-related projects and programs, PG&E utilized the IT Project  
5 Estimating Tool (PET). In instances where PG&E did not have the information  
6 necessary to complete a PET, a Job Estimate or Subject Matter Expert (SME)  
7 estimate was used. PG&E discusses its standard estimating methods for  
8 technology project investments in Exhibit (PG&E-7), Chapter 8. Historical spend  
9 patterns, subject matter expertise, and standard cost factors serve as primary  
10 inputs to the IT estimating tools used in this chapter to calculate labor and  
11 non-labor costs and document associated assumptions. Forecasts are  
12 sequenced to fit within high-level annual planning targets set by IT and  
13 Company leadership to align with strategic priorities.

14 PG&E developed the DM&A program forecast by first establishing target  
15 milestones in data management principles within the timeframe of the GRC,  
16 based on the Gartner Data Governance Maturity Model and the Data  
17 Management Framework discussed in the 2021 WMP.<sup>27</sup> Once target  
18 milestones were established, PG&E used internal and external subject matter  
19 expertise in order to estimate costs to reach and sustain those milestones. This  
20 process was iterated to optimize capability development within the timing and  
21 budget constraints of the GRC.

22 Project forecasts in the areas of Base Mapping, GIS Technical  
23 Enhancements, and GIS Asset Data Improvements were developed using  
24 subject matter expertise around anticipated units and unit costs of various types  
25 of asset registry corrections, as well as program budget expectations resulting  
26 from PG&E's internal investment planning process. Refer to Project Summary  
27 workpapers supporting this chapter for more information on the specific  
28 estimating methods used for each program.

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<sup>27</sup> PG&E's 2021 WMP Report, R.18-10-007 (February 5, 2021), Section 7.3.7.

1 **E. Compliance with Section 5.2 of the 2020 GRC Settlement Agreement**  
2 **(“Deferred Work Principles”)**

3 The 2020 GRC Settlement Agreement requires PG&E to include testimony  
4 in this GRC on deferred work if the following criteria are met:

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

11 Work that was authorized in the 2020 GRC for the MWCs in this chapter  
12 was not represented as needed to provide safe and reliable service, therefore  
13 Check 1 does not apply. Based on the results of this analysis, this chapter does  
14 not include deferred work as defined by the 2020 GRC Settlement Agreement.<sup>28</sup>

15 **F. Cost Tables**

16 The expense and capital forecasts for Data Management and  
17 Technology-related activities are summarized in the following tables:

- 18 • Table 20-19 lists expense MWCs showing 2016 through 2020 recorded  
19 adjusted expenses and 2021 through 2023 forecast expenses; and  
20 • Table 20-20 lists capital MWCs showing 2016 through 2020 recorded capital  
21 adjusted expenditures and 2021 through 2026 forecast expenditures.  
22

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<sup>28</sup> Exhibit (PG&E-4), WP 2-15.

**TABLE 20-19  
EXPENSE  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast			WP Reference
			2016	2017	2018	2019	2020	2021	2022	2023	
1	GE	E Dist Mapping	\$2,827	\$2,249	\$4,326	\$175	\$8,845	\$15,888	\$14,108	\$21,524	WP 20-1, line 1.
2	JV	Maintain IT Apps & Infra	2,233	6,054	5,860	1,647	2,810	3,777	3,333	4,501	WP 20-1, line 2.
3		Total	\$5,060	\$8,303	\$10,186	\$1,822	\$11,655	\$19,665	\$17,441	\$26,026	

**TABLE 20-20  
CAPITAL  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast			WP Reference		
			2016	2017	2018	2019	2020	2021	2022	2023		2024	2025
1	2F	Build IT Apps & Infra	\$21,715	\$21,077	\$19,586	\$5,084	\$22,788	\$17,696	\$21,997	\$16,597	\$16,499	\$18,506	WP 20-9, line 2.
2	21	Miscellaneous Capital	-	-	10	18	3	-	1,608	1,825	1,949	2,085	WP 20-9, line 1.
3		Total	\$21,715	\$21,077	\$19,596	\$5,102	\$22,791	\$17,696	\$23,605	\$18,421	\$18,448	\$20,591	

**PACIFIC GAS AND ELECTRIC COMPANY  
2023 GENERAL RATE CASE**

Testimony:  Workpapers:  SOQ:   
 Exhibit Number: 4 Chapter Number: 20  
 Chapter Title: Technology, Mapping and Asset Data Management  
 Witness Name: Jadwindar Singh

Page No.	Line No.	Item	As Filed	As Corrected
<b>Errata as of February 25, 2022</b>				
20-2	Line 18	N/A	Additionally, PG&E requests that the CPUC adopt its capital forecast for Electric Distribution Data Management and Technology projects and programs of \$17.7 million for 2021, \$23.6 million for 2022, \$19.9 million for 2023, \$19.0 million for 2024, \$19.4 million for 2025, and \$22.1 million for 2026. PG&E's 2023 forecast is approximately \$2.9 million lower than 2020 recorded capital expenditures of \$22.8 million.	Additionally, PG&E requests that the CPUC adopt its capital forecast for Electric Distribution Data Management and Technology projects and programs of \$17.7 million for 2021, \$23.6 million for 2022, \$19.7 million for 2023, \$18.4 million for 2024, \$18.4 million for 2025, and \$20.6 million for 2026. PG&E's 2023 forecast is approximately \$3.1 million lower than 2020 recorded capital expenditures of \$22.8 million.
20-5	Figure 20-2	Capital Expenditures	2022 Forecast \$23,602 2023 Forecast \$19,941 2024 Forecast \$19,989 2025 Forecast \$19,438 2026 Forecast \$22,126	2022 Forecast \$23,605 2023 Forecast \$19,700 2024 Forecast \$18,421 2025 Forecast \$18,448 2026 Forecast \$20,591

Page No.	Line No.	Item	As Filed	As Corrected
20-8	Line 25	N/A	PG&E is forecasting \$5.2 million expense in 2023, and capital expenditures forecasts of \$0 in 2021, \$1.0 million in 2022, \$1.3 million in 2023, \$1.7 million in 2024, \$2.1 million in 2025, and \$2.7 million in 2026 to support EO DM&A activities. This is an increase of \$1.1 million expense and \$1.3 million capital compared to 2020 recorded expenditures.	PG&E is forecasting \$5.2 million expense in 2023, and capital expenditures forecasts of \$0 in 2021, \$1.0 million in 2022, \$1.1 million in 2023, \$1.1 million in 2024, \$1.1 million in 2025, and \$1.1 million in 2026 to support EO DM&A activities. This is an increase of \$1.1 million expense and \$1.1 million capital compared to 2020 recorded expenditures.
20-12	Table 20-3	Capital Expenditures	2022 Forecast \$1,023 2023 Forecast \$1,295 2024 Forecast \$1,650 2025 Forecast \$2,101 2026 Forecast \$2,676	2022 Forecast \$1,026 2023 Forecast \$1,054 2024 Forecast \$1,082 2025 Forecast \$1,111 2026 Forecast \$1,141
20-39	Line 2	Estimating Methods	The estimating methodology used to develop the GRC forecast for this chapter was dependent on the type of work being performed. For all IT-related projects and programs, PG&E utilized the IT Project Estimating Tool.	The estimating methodology used to develop the GRC forecast for this chapter was dependent on the type of work being performed. For the vast majority of IT-related projects and programs, PG&E utilized the IT Project Estimating Tool (PET). In instances where PG&E did not have the information necessary to complete a PET, a Job Estimate or Subject Matter Expert (SME) estimate was used.
20-41	Table 20-20, Line 2	MWC 21	2022 Forecast \$1,604 2023 Forecast \$1,953 2024 Forecast \$2,392 2025 Forecast \$2,938 2026 Forecast \$3,620	2022 Forecast \$1,608 2023 Forecast \$1,712 2024 Forecast \$1,825 2025 Forecast \$1,949 2026 Forecast \$2,085
20-41	Table 20-20, Line 2	Total	2022 Forecast \$23,602 2023 Forecast \$19,941 2024 Forecast \$18,989 2025 Forecast \$19,438 2026 Forecast \$22,126	2022 Forecast \$23,605 2023 Forecast \$19,700 2024 Forecast \$18,421 2025 Forecast \$18,448 2026 Forecast \$20,591

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 21**  
**INTEGRATED GRID PLATFORM AND**  
**GRID MODERNIZATION PLAN**  
**[INCLUDES ERRATA THROUGH**  
**FEBRUARY 25, 2022]**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 21  
INTEGRATED GRID PLATFORM AND  
GRID MODERNIZATION PLAN  
[INCLUDES ERRATA THROUGH  
FEBRUARY 25, 2022]

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PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 21  
INTEGRATED GRID PLATFORM AND  
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[INCLUDES ERRATA THROUGH  
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1                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                                   **CHAPTER 21**  
3                   **INTEGRATED GRID PLATFORM AND**  
4                                   **GRID MODERNIZATION PLAN**  
5                   **[INCLUDES ERRATA THROUGH**  
6                                   **FEBRUARY 25, 2022]**

7   **A. Introduction**

8       **1. Scope and Purpose**

9           The purpose of this chapter is to demonstrate that Pacific Gas and  
10          Electric Company’s (PG&E or the Company) expense and capital  
11          expenditure forecasts for electric distribution projects related to Grid  
12          Modernization are reasonable and should be adopted by the California  
13          Public Utilities Commission (CPUC or Commission).

14          To support PG&E’s objective of providing secure, reliable, and resilient  
15          electricity that enables continued gains for clean energy technology and  
16          California’s economy in a way that gives our customers value, flexibility, and  
17          choice in how they use energy, PG&E needs to continue to improve its  
18          existing infrastructure and invest in new technologies. PG&E’s critical  
19          systems like Supervisory Control and Data Acquisition (SCADA) and its  
20          communication network must be improved in order to manage the growing  
21          number of devices on a more dynamic grid. At the same time, climate  
22          change and cybersecurity issues present new threats to the electric grid to  
23          which utilities throughout California, and the entire United States, must  
24          adapt.

25          In addition, the growth of Distributed Energy Resources (DER), such as  
26          distributed rooftop solar, behind-the-meter (BTM) energy storage, and  
27          electric vehicles, is creating a foundational paradigm shift in the electric grid  
28          as some consumers of electricity also become generators of electricity who  
29          both benefit from the grid and deliver benefits to it. Through the  
30          Commission-led Distribution Resources Plan (DRP) proceeding, PG&E  
31          continues to evaluate opportunities for enabling cost-effective DERs to be a  
32          part of reliable planning, operations, and investment processes.  
33          Specifically, as directed by the Commission’s decision (Decision

1 (D.) 18-02-004), PG&E submits annual Grid Needs Assessment (GNA) and  
2 Distribution Deferral Opportunity (DDOR) reports. These reports provide  
3 transparency into the assumptions and results of PG&E’s distribution  
4 planning process that yield a candidate deferral shortlist, proposed Grid  
5 Modernization investments, and proactive hosting capacity upgrades  
6 proposed to accommodate forecast DER growth. PG&E filed its most recent  
7 GNA<sup>1</sup> and DDOR<sup>2</sup> reports on August 17, 2020.

8 The Commission’s March 2018 Grid Modernization Decision  
9 (D.18-03-023) requires all investor-owned utilities (IOU) to submit a “Grid  
10 Modernization Plan” in their General Rate Case (GRC) filings that provides a  
11 10-year Grid Modernization vision and information for each proposed grid  
12 modernization program as described in Appendix A of the decision. This  
13 decision defined Grid Modernization expenditures as those having “any  
14 relationship with DER integration.”<sup>3</sup> This chapter presents PG&E’s forecast  
15 for electric distribution investments related primarily to Grid Modernization;  
16 additional Grid Modernization-related investments are located in other  
17 chapters within Exhibit (PG&E-4). In compliance with the Commission’s  
18 requirements, and consistent with PG&E’s approach in the 2020 GRC,  
19 tables demonstrating the location and cost of all the Grid Modernization  
20 investments in PG&E’s 2023 GRC filing are included as workpapers.<sup>4</sup>

21 The project portfolio presented in this chapter is a program of  
22 investments that will facilitate both DER enablement and safe and reliable  
23 operation of the electric grid. The goal of these projects is to modernize  
24 PG&E’s grid with improved situational awareness, operational efficiency,  
25 cybersecurity, and DER integration capabilities to meet today’s challenges  
26 while also positioning the grid to meet the demands of a dynamic energy  
27 future. PG&E uses the term “Integrated Grid Platform” (IGP) throughout the

---

1 PG&E’s 2020 Grid Needs Assessment (Aug. 17, 2020), at  
<<https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=619783>>  
(as of June 15, 2021).

2 PG&E’s 2020 Distribution Deferral Opportunity Report (Aug. 17, 2020), at  
<<https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=619785>>  
(as of June 15, 2021).

3 D.18-03-023, p. 8.

4 See Exhibit (PG&E-4) WP 21-14 and WP 21-16.

1 chapter to refer to the closely linked Advanced Distribution Management  
2 System (ADMS), Distributed Energy Resource Management System  
3 (DERMS), and IGP Information Technology (IT) Infrastructure projects,  
4 which together will constitute an efficient and modern operational platform  
5 capable of responding to emergent challenges posed by DERs and  
6 cybersecurity threats. Other proposed investments in this chapter, including  
7 Distribution Engineering Planning Tools, the Community Microgrid  
8 Enablement Program (CMEP), the Electric Emerging Technology Program,  
9 and the Elkhorn Battery Energy Storage System<sup>5</sup> are Grid  
10 Modernization-related, but not considered part of “IGP” because they are not  
11 related to real-time distribution grid operations.

12 To provide the context for the Grid Modernization requests in this  
13 chapter, PG&E’s 10-year Grid Modernization vision and strategy is included  
14 in Attachment A to this chapter. While its fundamentals are unlikely to  
15 change, PG&E’s vision will evolve in parallel with the direction of California’s  
16 energy policy as PG&E continues to work with customers, regulators, and  
17 technology providers to build a safe, reliable, and resilient grid. As required  
18 by the Commission, PG&E conducted a workshop on its Grid Modernization  
19 Plan on April 26, 2021; this chapter reflects PG&E’s presentation at that  
20 workshop and considers the input provided by stakeholders at the  
21 workshop.

22 This chapter was updated as part of the February 25, 2022 submittal  
23 remove the Electric Program Investment Charge (EPIC) Program funding  
24 from the GRC as described in PG&E’s opening testimony, pending renewal  
25 of the EPIC program.<sup>6</sup>

## 26 **2. Summary of Request**

27 PG&E requests that the Commission adopt its 2023 expense forecast  
28 of \$49.1 million to support PG&E’s Grid Modernization Plan, including  
29 ADMS, DERMS, CMEP, Distribution Engineering Planning Tools,  
30 Distribution Deferral Non-Procurement Costs, IGP IT Infrastructure, and the

---

5 The Elkhorn Battery Energy Storage System is also known as the Moss Landing Battery Energy Storage System.

6 See Exhibit (PG&E-4), Page 21-27, Lines 2-5.

1 Electric Emerging Technology Program. PG&E's 2023 expense forecast is  
2 \$23.9 million more than its 2020 recorded costs of \$25.2 million.<sup>7</sup>

3 Additionally, PG&E requests that the Commission adopt its capital  
4 expenditure forecast of \$104.4 million in 2021, \$147.9 million in 2022,  
5 \$131.7 million in 2023, \$89.0 million in 2024, \$42.2 million in 2025, and  
6 \$43.4 million in 2026 to support foundational investments in PG&E's IGP  
7 and Grid Modernization plan. PG&E's 2023 capital forecast is \$26.0 million  
8 less than its 2020 recorded costs of \$157.6 million.<sup>8</sup>

9 Note that this summary of PG&E's request does not include the expense  
10 or capital forecasts for the Elkhorn Battery Energy Storage System in the  
11 years 2021-2023 because they are market sensitive. PG&E will describe  
12 the work in this chapter, but the full project forecast is being provided in a  
13 confidential appendix.<sup>9</sup>

14 Forecasts in this chapter are shown with escalation at the Major Work  
15 Category (MWC) level and escalation is included in all expense and capital  
16 totals. For more information on escalation, please refer to Chapter 2 of this  
17 exhibit.

### 18 **3. Overview of Recorded and Forecast Costs**

19 PG&E uses the MWCs shown in Table 21-1 to record Grid  
20 Modernization-related expenditures for capital and expense.

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7 See Exhibit (PG&E-4), WP 21-1, line 6.

8 See Exhibit (PG&E-4), WP 21-6, line 9.

9 See Exhibit (PG&E-4), Appendix A.

**TABLE 21-1  
GRID MODERNIZATION MWCs**

Line No.	MWCs	Description
1	Expense MWCs	
2	HG	Tracks Distribution Operation Technology-related expenses, including Ch. 21 forecast for ADMS and DERMS.
3	JV	Tracks IT-related expenses, including Ch. 21 forecast for IGP IT Infrastructure and non-DRP-related Distribution Engineering Planning Tools.
4	AT	Tracks expenses associated with <del>Research and Development (R&amp;D)</del> emerging technology activities, including the <del>Ch. 21 recorded costs for the Electric Program Investment Charge (EPIC) Program</del> and forecast for the Electric Emerging Technology Program.
5	AB	Tracks miscellaneous expenses, including Ch. 21 forecast for the Elkhorn Battery Energy Storage System, CMEP beginning in 2023, and DRP-related Distribution Engineering Planning Tools.
6	IG	Tracks expenses associated with miscellaneous balancing or memorandum accounts, including Ch. 21 forecast for CMEP through 2022 and DRP Non-Procurement Costs.
7	Capital MWCs	
8	63	Tracks Distribution Operation Technology capital investments, including Ch. 21 forecast for ADMS and DERMS.
9	2F	Tracks IT capital investments, including Ch. 21 forecast for IGP IT Infrastructure and non-DRP-related Distribution Engineering Planning Tools.
10	21	Tracks miscellaneous capital investments, including Ch. 21 forecast for DRP-related Distribution Engineering Planning Tools.
11	3M	Tracks capital investments associated with miscellaneous balancing or memorandum accounts, including Ch. 21 recorded costs related to the Smart Grid Pilot Project.
12	3R	Tracks energy storage capital investments, including Ch. 21 forecast for the Elkhorn Battery Energy Storage System.
13	82	Tracks capital investments associated with Transmission interconnection, including Gen-Tie work for the Elkhorn Battery Energy Storage System.

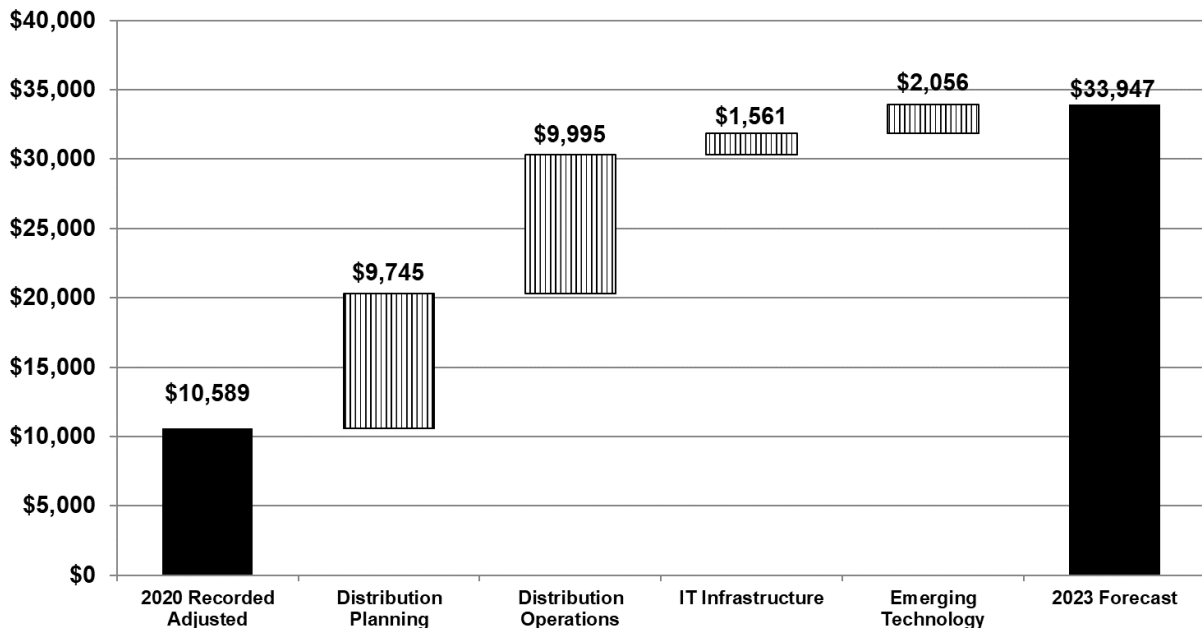
1           **a. Expense**

2                         Figure 21-1 shows the walk from 2020 recorded expenses to the  
3                         2023 expense forecast. This figure includes costs that are subject to  
4                         recovery on a recorded basis through accounts including the Distributed  
5                         Energy Resources Distribution Deferral Account (DERDDA), Avoided  
6                         Costs Calculator Update Memorandum Account (ACCUMA), Distribution  
7                         Resources Plan Tools Memorandum Account (DRPTMA), New System  
8                         Generation Balancing Account (NSGBA), and the Microgrids  
9                         Memorandum Account (MGMA). These amounts are included for

1 trending purposes because the activity will become GRC funded  
2 beginning in 2023.

3 PG&E's 2023 forecast of \$49.1 million is \$23.9 million higher than its  
4 2020 recorded expenses of \$25.2 million.<sup>10</sup> Reasons for the increase  
5 between 2020 and 2023 include: an increase in ADMS activity  
6 associated with the initiation of activities associated with Outage  
7 Management System (OMS) replacement and Advanced Application  
8 implementation, an increase in CMEP program activity, and an increase  
9 in non-procurement costs for DRP distribution deferral projects. There  
10 is an additional increase due to the beginning of operations and  
11 maintenance (O&M) on the Elkhorn Battery Energy Storage System  
12 which is not shown here but which is described in confidential  
13 Appendix A.<sup>11</sup>

**FIGURE 21-1**  
**EXPENSE WALK 2020-2023**  
**(THOUSANDS OF NOMINAL DOLLARS)**



<sup>10</sup> See Exhibit (PG&E-4), WP 21-1, line 6.

<sup>11</sup> See Exhibit (PG&E-4), Appendix A.

1           **b. Capital**

2           Figure 21-2 shows 2020 recorded capital expenditures and the  
3           capital forecast for 2021-2026.<sup>12</sup> This figure includes costs that are  
4           subject to recovery on a recorded basis through accounts including the  
5           DRPTMA and the NSGBA; these amounts are included for trending  
6           purposes because the activity will become GRC funded beginning in  
7           2023.

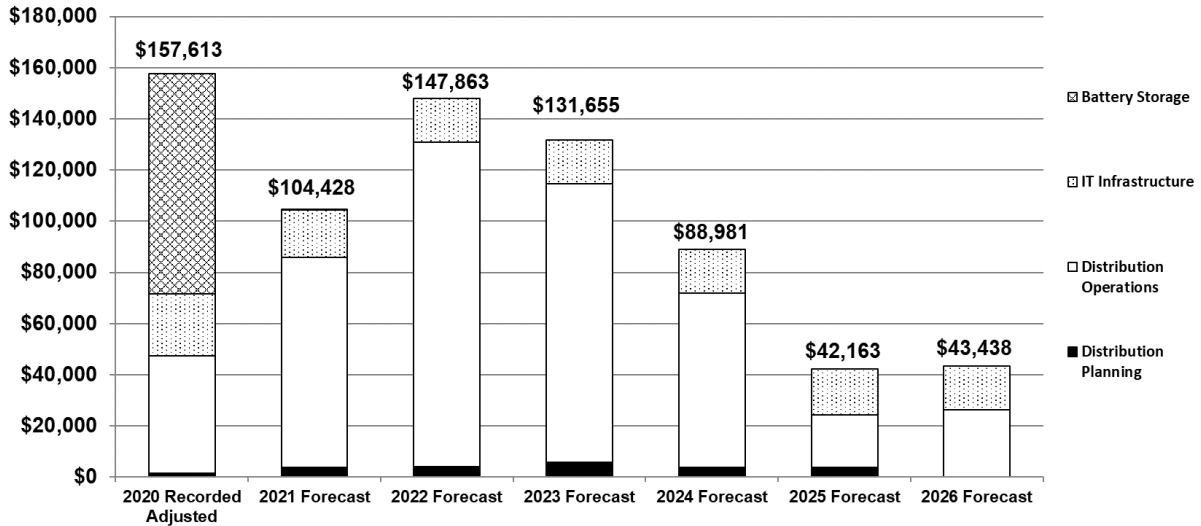
8           PG&E's 2023 forecast of \$131.7 million is \$26.0 million lower than  
9           the 2020 recorded costs of \$157.6 million.<sup>13</sup> The primary reasons for  
10          the decrease are the conclusion of construction on the Elkhorn Battery  
11          Energy Storage System and a reduction in spending on IT  
12          Infrastructure, which outweighed increases in ADMS Program spending  
13          related to the initiation of activities associated with OMS replacement  
14          and Advanced Application implementation.

---

<sup>12</sup> Some values vary from the values listed in the Results of Operations (RO) Model due to errata. These amounts do not align to the RO Model provided to the Public Advocates Office at the time of filing. The RO will be updated to incorporate these errata with the Joint Comparison Exhibit submittal.

<sup>13</sup> See Exhibit (PG&E-4) WP 21-6, line 9.

**FIGURE 21-2  
CAPITAL RECORDED AND FORECAST 2020-2026  
(THOUSANDS OF NOMINAL DOLLARS)**



1 **c. Cost Allocation**

2 Consistent with the allocation of electric distribution-related capital  
3 and expense costs generally for recovery in electric distribution rates  
4 under GRC decisions and decisions in the DRP and Integrated  
5 Distributed Energy Resources (IDER) proceedings, the costs of Grid  
6 Modernization and DRP/IDER-related distribution deferral and  
7 administrative costs should be allocated for recovery in electric  
8 distribution rates in this GRC.<sup>14</sup> These costs should be allocated to  
9 electric distribution rates because bundled and non-bundled customers  
10 will share equally in all Grid Modernization program benefits, including  
11 benefits related to cybersecurity, reliability, safety, energy savings,  
12 improved management of DER-related grid issues, and enablement of  
13 DER-provided grid services. Moreover, the real-time data produced by  
14 PG&E’s Grid Modernization investments do not advantage PG&E in

---

<sup>14</sup> An exception is the cost associated with the Elkhorn Battery Energy Storage System, described in Section C.5, which is recovered via the NGSBA.

1 identifying DER siting opportunities<sup>15</sup> or within any future distribution  
2 market construct wherein DER dispatch is governed by  
3 ownership-agnostic optimization algorithms.

#### 4 **4. Support for Request**

5 PG&E's expense and capital forecasts in this chapter are reasonable  
6 because they are required to reduce cybersecurity risk and address  
7 challenges stemming from an increasing number of DERs on the grid.  
8 Specifically, the benefits enabled by this chapter's forecast include:

- 9 • Reduced cybersecurity risk from replacement of the antiquated  
10 Real-Time Supervisory Control and Data Acquisition (RT-SCADA)  
11 system;
- 12 • Improved management of DER-related grid issues through awareness  
13 of masked load and thermal, voltage, and protection issues;
- 14 • Dispatch of DER to mitigate real-time and forecasted grid constraints;
- 15 • Reliability improvements from ADMS fault location and automated  
16 switching capabilities;
- 17 • Operational efficiency improvements through automation of manual  
18 tasks in ADMS;
- 19 • Reduced lifecycle technology cost through consolidation of disparate  
20 grid management applications into an ADMS;
- 21 • Upgraded IT infrastructure to more reliably transmit larger volumes of  
22 data;
- 23 • Planning tools that will enable PG&E to fully analyze grid impacts of  
24 DER;
- 25 • Engineering and design support for community microgrids; and  
26 • Continuation of PG&E's electric emerging technology R&D work.

27 PG&E's Grid Modernization forecast builds on past investments and  
28 R&D technology demonstrations and takes a cost-conscious, conservative  
29 approach to create a foundation for modern grid operations.

---

<sup>15</sup> PG&E publicly shares the Locational Net Benefits Analysis (LNBA), Integration Capacity Analysis (ICA), GNA, and DDOR data that are useful in identifying DER siting opportunities.

## 5. Organization of the Remainder of This Chapter

The remainder of the chapter is organized as follows:

- Section B – Program and Risk Overview;
- Section C – Activities, Costs, and Forecast Drivers by MWC;
- Section D – Estimating Methods;
- Section E – Compliance with Prior Commission Decisions;
- Section F – Balancing and Memorandum Accounts;
- Section H – Cost Tables;
- Attachment A – PG&E’s Grid Modernization Plan – 10 Year Vision;
- Attachment A1 – Grid Modernization Plan – Upgrades Initiated or Completed to Date;
- Attachment A2 – DER-Related Research, Development, and Demonstration Projects; and
- Attachment A3 – Community Microgrid Enablement Program Evaluation.

### B. Program and Risk Overview

#### 1. Program Description

##### a. Program Overview

This chapter presents a diverse portfolio of projects that help PG&E respond to the challenges and opportunities presented by the growing adoption of DER on the grid. When fully implemented, these projects will prepare PG&E to respond to DER-driven challenges on three key time scales:

- Real-Time/Operational – The IGP, including ADMS, DERMS, and IT Infrastructure, will provide PG&E with the grid management tools and communications infrastructure needed to promote awareness of, and effective responses to, DER-related issues occurring in real-time. DERMS will enable PG&E to proactively dispatch DER in response to grid issues, effectively harnessing the ability of DER to serve as a positive force on the distribution grid, rather than as a source of issues that need to be managed.
- Medium-Term/Planning – The Distribution Planning Tool enhancement work in this chapter will provide PG&E with the analytical capabilities needed to plan grid infrastructure upgrades or

1           deferrals amid the heightened complexity driven by the time-of-day  
2           and seasonal variability of DER. Additionally, the CMEP will bring  
3           PG&E engineering expertise to bear to help plan the development of  
4           microgrids.

- 5           • ~~Long-Term/R&D~~ Emerging Technology – The Emerging Electric  
6           Technology Program will assist DER integration capability in the  
7           longer term through a series of external innovation partnerships that  
8           will keep PG&E informed of the external technology landscape and  
9           industry trends, and facilitate coordination with external groups to  
10          identify technology solutions that address PG&E’s greatest  
11          challenges. ~~field demonstration of emerging technologies, a vital~~  
12          ~~first step to scaling any new technology within core Company~~  
13          ~~operations.~~

14           Although the projects presented in this chapter are largely driven by  
15          the need to accommodate DER, they provide many additional benefits.  
16          These benefits include improved cybersecurity and reliability  
17          performance, increased operational efficiency, integration of mission  
18          critical operational tools, reduced technical debt, improved safety, more  
19          targeted and efficient Public Safety Power Shutoffs (PSPS), and  
20          non-DER-related innovation partnerships in areas such as safety,  
21          reliability, resiliency, and affordability.

## 22          **b. Management Structure**

23           The Grid Modernization projects in this chapter will be managed by  
24          various teams across PG&E:

- 25          • ADMS and DERMS are cross-functional programs centrally  
26          managed by the witness—the Director of the IGP Program, under  
27          Transmission Operations—and implemented in conjunction with  
28          Distribution Asset Management, Distribution Operations, Distribution  
29          Engineering, and various IT organizations;
- 30          • The Infrastructure and Operations team within PG&E’s IT  
31          organization manages deployment of IT Infrastructure improvements  
32          discussed in this chapter;
- 33          • Distribution Engineering Planning Tools projects are managed by  
34          PG&E’s Asset Planning and Integrated Grid Planning teams;

- 1 • CMEP will be managed by the Microgrid Policy & Pricing Strategy
- 2 team within PG&E's Energy Strategy and Innovation Group;
- 3 • The Electric Emerging Technology Program is managed by the
- 4 Emerging Technology Strategy and Programs team within PG&E's
- 5 Asset Knowledge Management organization, ~~the same team that~~
- 6 ~~currently manages PG&E's EPIC Program~~; and
- 7 • The Elkhorn Battery Energy Storage System is managed by the
- 8 Major Projects and Programs team within Electric Operations (EO).

## 9 **2. Risk Integration**

10 Risk controls and mitigations are aligned to various MWCs and MATs in  
11 Electric Distribution. None of the MWCs presented in this chapter  
12 correspond to a risk mitigation or risk control that address a risk on Electric  
13 Operation's Corporate Risk Register. More information about risk  
14 mitigations and controls is in PG&E's Electric Distribution Risk Management  
15 testimony (Exhibit (PG&E-4), Chapter 3).

## 16 **C. Activities, Costs and Forecast Drivers by MWC**

### 17 **1. Distribution Planning Programs**

#### 18 **a. Distribution Engineering Planning Tools**

19 Distribution planning is becoming increasingly complex as new  
20 sources of data need to be integrated to support accurate system  
21 modeling. Advanced planning tools are the foundation for well-planned  
22 grid infrastructure improvements because they will allow PG&E to  
23 evaluate a wider variety of scenarios and conditions created by an  
24 increasingly dynamic and distributed electric grid. The advanced  
25 capabilities required include the ability to forecast load under a variety of  
26 scenarios and the ability to perform time series analysis of the  
27 distribution system (i.e., conditions at many different times of day or  
28 year, or in varying weather conditions) to forecast long-term and  
29 near-term planning deficiencies and constraints.

30 PG&E's Distribution Engineering Planning Tools forecast is split  
31 between tool development work driven by DRP compliance, which is  
32 tracked in MWCs 21 and AB, and tool enhancements driven by business  
33 needs unrelated to the DRP, which are tracked in MWCs 2F and JV.

1 Planning Tool Development Driven by DRP Compliance

2 Multiple tracks within the DRP<sup>16</sup> have required the creation and use  
 3 of new tools including Integration Capacity Analysis (ICA),<sup>17</sup> Locational  
 4 Net Benefit Analysis (LNBA),<sup>18</sup> and the DRP Data Portal.<sup>19</sup> The DRP  
 5 also required the ongoing analysis and publication of distribution data  
 6 via the GNA and DDOR [annual reports](#).<sup>20</sup> The scale of the data and  
 7 analysis requires specific and customized tools to process and promote  
 8 data quality and accuracy.

9 These requirements from the DRP require PG&E to make upgrades  
 10 to existing planning tools, including CYME, a tool used by PG&E  
 11 engineers to model power flows on the distribution grid, study scenarios,  
 12 and plan grid reconfigurations or upgrades, and LoadSEER, the  
 13 Company's core load forecasting tool. The new functionalities delivered  
 14 by this project will include:

- 15 • Scenario Planning – Studying distribution system impacts across  
 16 various forecast and planning scenarios.
- 17 • Load Forecasting Enhancements – Forecasting load more  
 18 granularly, at the line section level, and performing short-term load  
 19 forecasts for DER dispatch.
- 20 • Tools Integration – Eliminating manual processes by automating the  
 21 integration of various distribution planning tools.
- 22 • Report Process Management – Automating the process and  
 23 creation of Distribution Investment Deferral Framework (DIDF)  
 24 reports.

25 Non-DRP-Related Distribution Planning Tool Enhancements

26 This project proposes several enhancements to the CYME  
 27 application and study process driven by business needs unrelated to the  
 28 DRP. The forecast in MWCs 2F and JV through 2022 covers the

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16 *Order Instituting Rulemaking* (OIR), R.14-08-013 (Aug. 20, 2014).

17 D.17-09-026.

18 D.17-09-026.

19 D.18-02-004.

20 D.18-02-004.

1 “Distribution Engineering Planning Tools” project described in the 2020  
2 GRC. The 2023-2026 forecast for these MWCs covers the following  
3 new projects:

- 4 • CYME Substation Modeling & Analysis – This project will model the  
5 distribution substation within CYME, including, but not limited to,  
6 substation transmission protective devices at the interface between  
7 transmission and distribution, transformer banks, substation buses,  
8 and distribution breakers. Adding new substation components into  
9 the CYME model will allow for additional analyses to be performed  
10 within the CYME application. The current process requires  
11 engineers to do some of the substation-level analyses outside of  
12 CYME, either in separate protection analysis tools, spreadsheets, or  
13 on paper. Further incorporating the substation model into  
14 distribution planning software allows engineers to further study  
15 within CYME bank and feeder level upgrades, bank and feeder loss  
16 studies, substation elements of the distribution protection studies,  
17 and bank and feeder capability ratings.
- 18 • Distribution Time-Series Analysis Phase 2 – This project will build  
19 upon the successful implementation of the CYME Time-Series Load  
20 Flow Analysis project and further automate the distribution planning  
21 process. This project will extend the existing time-series analysis to  
22 assist with Voltage Regulator and Capacitor optimization and Risk  
23 Prioritization. Additionally, this project will investigate the use of the  
24 Advanced Project Manager, results from the time-series analysis,  
25 and the technoeconomic analysis module to generate standardized  
26 and templated project authorization documentation.
- 27 • Distribution Planning Automation – The Distribution Planning  
28 Automation project will develop a manage-by-exception analysis  
29 process within CYME for capacity planning study deficiencies.  
30 Circuit analyses will be initiated and reviewed at the dashboard  
31 level, allowing engineers to focus their review on circuits with  
32 forecasted deficiencies. Distribution planning tools will also be  
33 further integrated with two-way information flow.

1 PG&E's forecast for the Distribution Engineering Planning Tools  
 2 project has both an expense and capital expenditure component and is  
 3 summarized in Tables 21-2 and 21-3 below. The 2023 Distribution  
 4 Engineering Planning Tools forecast is higher than 2020 recorded costs  
 5 due to an anticipated increase in tool development work driven by new  
 6 requirements from the DRP and enhancements to PG&E's distribution  
 7 planning processes. Project work is expected to conclude in 2025.

**TABLE 21-2**  
**DISTRIBUTION ENGINEERING PLANNING TOOLS**  
**RECORDED AND FORECAST EXPENSE**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	Workpaper Reference
1	Expense (MWC AB)	\$3,320	\$3,926	\$4,135	\$4,565	WP 21-5, line 29.
2	Expense (MWC JV)	298	215	200	1,009	WP 21-5, line 14.
3	Total	\$3,618	\$4,141	\$4,335	\$5,574	

**TABLE 21-3**  
**DISTRIBUTION ENGINEERING PLANNING TOOLS**  
**RECORDED AND FORECAST CAPITAL**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Workpaper Reference
1	Capital (MWC 21)	\$395	\$2,882	\$3,083	\$2,237	\$1,852	\$1,902	-	WP 21-12, line 21.
2	Capital (MWC 2F)	1,180	1,050	1,000	3,469	1,886	1,995	-	WP 21-12, line 12.
3	Total	\$1,575	\$3,932	\$4,083	\$5,706	\$3,738	\$3,897	-	

8 **b. Distribution Deferral Non-Procurement Costs**

9 PG&E is responsible for providing deferral of distribution services  
 10 via the DRP (R.14-08-013), as well as Incentive Pilots via the DERDDA  
 11 (R.14-10-003). Through the DRP, PG&E has developed the DIDF to  
 12 procure, through third party vendors, Distribution Deferral services to  
 13 replace or defer traditional wire-based projects in the Company's project  
 14 planning pipeline.

15 To comply with these requirements, PG&E administers the DIDF to  
 16 select the best candidates for potential deferral of distribution services.

1 The culmination of this process is procurement of distribution deferral  
2 services via a Request for Offers (RFO) from third parties. Per  
3 Commission direction (D.16-12-036 and D.18-02-004), the direct  
4 procurement and administrative costs associated with these contracts  
5 may be recovered in the GRC as recorded in the DERDDA, but no such  
6 costs are included in this GRC because no actual procurement costs  
7 have yet been incurred. The forecast for this GRC period therefore only  
8 includes the non-procurement administrative costs associated with  
9 these contracts, which were also directed to be recovered in the GRC  
10 per D.16-12-036 and D.18-02-004.

11 PG&E has followed the specific CPUC compliance requirements of  
12 the DRP (R.14-08-013) and the DERDDA (formerly the Integrated  
13 Distributed Energy Resources Account (IDERA)) to track  
14 non-procurement costs. These non-procurement costs encompass both  
15 the DERDDA incentive pilots, as well as the DRP DIDF DER Projects.

16 The forecast also includes payments made by PG&E to contractors  
17 for updates to the Avoided Cost Calculator. Commission decision  
18 D.16-06-007 directed PG&E to track these costs in the ACCUMA and  
19 recover these costs in the GRC.

20 In summary, the non-procurement costs covered by this forecast  
21 include but are not limited to:

- 22 • The solicitation process (including RFOs);
- 23 • Development and administration of contracts;
- 24 • Ongoing testing and validation of deployed DERs;
- 25 • Ongoing project and contract management costs;
- 26 • Contingency planning costs, developed in conjunction with PG&E's  
27 Distribution Planning group, to enable continued operation of the  
28 grid; and
- 29 • Costs associated with updates to the Avoided Cost Calculator.

30 The forecast for Distribution Deferral Non-Procurement costs only  
31 has an expense component, and is summarized in Table 21-4, below.  
32 The 2023 forecast is higher than 2020 recorded costs due to an  
33 anticipated increase in DRP DIDF and DER Tariff Pilot Program  
34 activities.

**TABLE 21-4**  
**DISTRIBUTION DEFERRAL NON-PROCUREMENT COSTS**  
**RECORDED AND FORECAST COSTS**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	Workpaper Reference
1	Expense (MWC IG)	\$296	\$926	\$2,419	\$3,026	WP 21-5, line 34.

1                    PG&E proposes to continue the DERDDA to record amounts above  
2                    the adopted GRC forecast. PG&E proposes to continue recording to the  
3                    ACCUMA as well.

4                    **c. Community Microgrid Enablement Program**

5                    PG&E's CMEP was introduced in Track 1 of the Microgrid OIR<sup>21</sup> as  
6                    part of PG&E's proposal to address PSPS mitigation and support energy  
7                    resilience for our customers and communities. CMEP's approach is to  
8                    empower communities directly through a combination of technical and  
9                    financial assistance, as well as through development of the tariffs and  
10                    agreements necessary to facilitate multi-customer microgrids.

11                    The CMEP will help surmount the technical, financial, legal, and  
12                    regulatory challenges inherent in scaling novel microgrid technology  
13                    deployments. While CMEP provides tools and information for all forms  
14                    of resilience solutions, including BTM installations, the focus of the  
15                    program is on facilitating the development of front-of-the-meter (FTM),  
16                    multi-customer microgrids. The CMEP program consists of four  
17                    elements:

- 18                    • Web-Based Tools and Information – PG&E's Community Resilience  
19                    Guide ([www.pge.com/resilience](http://www.pge.com/resilience)) provides financial, technical, and  
20                    interconnection resources for community resilience projects.
- 21                    • Enhanced Utility Technical Support – PG&E provides incremental  
22                    support through a 3-stage process to facilitate development of  
23                    multi-customer microgrids from initial concept exploration, through  
24                    solution assessment, to solution execution.

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<sup>21</sup> OIR, R.19-09-009 (Sept. 19, 2019).

- 1 • Community Microgrid Enablement Tariff – PG&E submitted a pro  
2 forma tariff in Advice Letter 5918-E to govern the eligibility,  
3 development, and island and transitional operation of community  
4 microgrids.
- 5 • Cost Offsets – PG&E will offset the cost of equipment necessary to  
6 enable the safe islanding of a community microgrid, up to \$3 million  
7 per project.

8 In D.20-06-017, the CPUC approved PG&E’s CMEP request of  
9 \$6.75 million in capital for 2020, \$27 million in capital for 2021,  
10 \$27 million in capital for 2022, and \$3 million in expense for each year  
11 2020-2022; the CPUC also authorized PG&E to record CMEP costs in a  
12 new MGMA.<sup>22</sup>

13 In this GRC application, PG&E seeks authorization for the costs  
14 associated with maintaining the Web-based Tools and Information and  
15 Enhanced Utility Technical Support components of CMEP beyond 2022  
16 because it believes that these functions will remain critical to support the  
17 growth of multi-customer microgrids. In fact, with the CPUC’s adoption  
18 of a new Microgrid Incentive Program (MIP) in Track 2 of the Microgrid  
19 OIR,<sup>23</sup> which may be approved in its full form in 2022, PG&E anticipates  
20 a significant MIP-driven increase in community demand for microgrid  
21 development and technical support. As a result, PG&E’s 2023 CMEP  
22 expense forecast is higher than its 2020 recorded costs and 2021 and  
23 2022 forecast.

24 PG&E does not seek additional capital beyond the funding already  
25 authorized in D.20-06-017 for the Cost Offsets portion of CMEP. In  
26 accordance with D.20-06-017, Ordering Paragraph 16, PG&E intends to  
27 recover costs for CMEP capital and expense through 2022 via a  
28 reasonableness review application after such costs have been recorded  
29 in the MGMA.

30 The forecast for CMEP, which is comprised only of expense  
31 components, is summarized in Table 21-5 below. The 2023 forecast is

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<sup>22</sup> R.19-09-009, Exhibit (PG&E-1), Ch. 5, p. 5-7, Table 6-1, and p. 5-8, fn. 9.

<sup>23</sup> D.21-01-018, Section 3.4, starting at p. 55.

1 higher than 2020 recorded costs because the 2020 recorded costs do  
 2 not reflect a full year of program activity and because an increase in  
 3 microgrid development activity is anticipated following the Commission's  
 4 expected 2022 approval of the MIP.

**TABLE 21-5  
 COMMUNITY MICROGRID ENABLEMENT PROGRAM  
 RECORDED AND FORECAST COSTS  
 (THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Cost	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	Workpaper Reference
1	Expense (MWC IG)	\$391	\$3,088	\$3,177	–	WP 21-5, line 33
2	Expense (MWC AB)	–	–	–	\$5,450	WP 21-5, line 30
3	Total	\$391	\$3,088	\$3,177	\$5,450	

## 5 **2. Distribution Operations Programs**

### 6 **a. Advanced Distribution Management System**

7 This project continues PG&E's multiyear implementation of ADMS, a  
 8 platform that will integrate several mission critical Distribution Operator  
 9 (DO) applications currently spread across multiple platforms. The  
 10 ADMS will become PG&E's core distribution operations technology tool  
 11 to enable the visibility, control, forecasting, and analysis of a more  
 12 dynamic grid. Greater visibility and control of the grid are needed for  
 13 PG&E to continue providing safe and reliable service to customers in the  
 14 face of the increasing complexity of the grid due to DER adoption, the  
 15 apparent "new normal" of weather-related emergencies, evolving  
 16 California energy policy requirements, and increasing cyber-security  
 17 threats.

18 When fully deployed, the ADMS platform will bring Distribution  
 19 Supervisory Control and Data Acquisition (D-SCADA), Distribution  
 20 Management System (DMS), and OMS into a single, modernized  
 21 platform. The components that will ultimately be brought together in the  
 22 proposed ADMS platform are described below.

- 23 • D-SCADA – PG&E's D-SCADA system gathers, processes, and  
 24 displays systemwide operating data to DOs at control centers.

25 Operators use the system to remotely control and/or operate

1 devices on the distribution network. The D-SCADA system consists  
2 of distributed IT network system and server hardware and a growing  
3 number of SCADA-enabled field devices which send and receive  
4 real-time data over the network.

- 5 • Distribution Management System – DMS is a system that utilities  
6 use to maintain an “As-Operated” model of the electric distribution  
7 grid and to run advanced applications that analyze and control the  
8 grid. Examples of these advanced applications include Fault  
9 Location, Isolation, and Service Restoration, Volt/Var Optimization,  
10 Restoration Switching Analysis, and Switch Planning and Execution.
- 11 • Outage Management System – OMS is a network model-based  
12 system used to identify electrical outage locations and assist in the  
13 restoration of power. This system also provides utility customers  
14 with updated outage information and is the source for reliability  
15 reporting. The accuracy of OMS’s identification of outages is  
16 dependent on its network model reflecting the actual as-switched  
17 state of the distribution system at any given time.

18 The three primary justifications for the ADMS project highlighted in  
19 the 2020 GRC remain in force today:

- 20 • PG&E’s D-SCADA Application Needs to be Replaced. PG&E’s  
21 existing D-SCADA application is outdated. RT-SCADA, the current  
22 application managing data exchange between field devices,  
23 processors/servers, and displays in the Distribution Control Center  
24 (DCC), does not have the functionality and cybersecurity features to  
25 address future grid conditions, including an increased number of  
26 field devices and increased DER penetration. RT-SCADA cannot  
27 reliably be integrated with other distribution control applications,  
28 cannot support the data volume and advanced applications required  
29 for future grid conditions, and is not equipped with best in class  
30 cybersecurity defenses. RT-SCADA will be replaced as part of the  
31 implementation of ADMS.
- 32 • Integrating PG&E’s Core Distribution Grid Operational Technologies  
33 Will Be Beneficial. Today, DOs use multiple applications  
34 concurrently, sometimes manually transferring information between

1 these systems. While this has worked in the past, it is a source of  
2 human error, creates duplicative work, and limits PG&E’s ability to  
3 use technology to automate processes and drive efficiencies.  
4 Implementing an ADMS platform with a common data source for the  
5 “As-Operated” grid state and real-time SCADA states will avoid  
6 these issues, allowing DOs to perform higher value activities.

- 7 • PG&E’s Distribution Grid Operational Technology Needs to  
8 Accommodate Future DER Growth and Evolving California Energy  
9 Policy Requirements. PG&E’s existing operating technology is not  
10 well-suited to operate the grid as DER penetration increases.  
11 PG&E’s D-SCADA and DMS systems were not designed with the  
12 grid operating conditions created by high volume and penetration of  
13 DERs in mind, nor were they designed to efficiently integrate with  
14 other systems envisioned to enable to DERs to provide distribution  
15 services, such as DERMS and/or Demand Response Management  
16 System (DRMS).<sup>24</sup>

17 To consolidate all integral ADMS Program work into a single  
18 location, in this GRC PG&E has merged two workstreams that were  
19 previously forecasted outside of ADMS into the broader ADMS program  
20 forecast. These include:

- 21 • ADMS Asset Data – This workstream’s goal is to execute on data  
22 enhancement initiatives, including enhancements to Phase ID data,  
23 that will directly facilitate the build of the ADMS network model or  
24 improve the quality of ADMS power flow solutions. In the 2020  
25 GRC, this workstream was forecasted as the “Distribution GIS Asset  
26 Data Improvement” project.<sup>25</sup>
- 27 • ADMS Cybersecurity – This workstream’s goal is to enact an  
28 industry leading cybersecurity design supporting the new ADMS that  
29 will mitigate security risks and counter an advancing threat  
30 landscape against the electric distribution grid. In the 2020 GRC,

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<sup>24</sup> DRMS is the IT system that processes enrollments, registration to the California Independent System Operator (CAISO), management of aggregated resources, dispatch events of PG&E’s Demand Response events, and retail settlements.

<sup>25</sup> A.18-12-009, HE-17: Exhibit (PG&E-4), Ch. 19, p. 19-19, line 6 to p. 19-28, line 8.

1 this workstream was forecasted as the “IGP Cybersecurity  
2 Project.”<sup>26</sup>

3 The forecast for ADMS, which has both an expense and capital  
4 expenditure component, is summarized in Table 21-6, below. The 2023  
5 forecast is higher than 2020 recorded costs due the initiation of work  
6 associated with OMS replacement in 2021 and Advanced Application  
7 implementation in 2022.

**TABLE 21-6**  
**ADVANCED DISTRIBUTION MANAGEMENT SYSTEM**  
**RECORDED AND FORECAST COSTS**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Workpaper Reference
1	Capital (MWC 63)	\$44,373	\$81,885	\$126,880	\$108,074	\$64,037	–	–	WP 21-12, lines 3-8. WP 21-5, lines 3-9.
2	Expense (MWC HG)	5,154	5,424	2,287	15,422	10,246	–	–	
3	Total	\$49,528	\$87,309	\$129,167	\$123,496	\$74,283	–	–	

8 **b. Distributed Energy Resource Management System**

9 As DER penetration increases, new distribution system challenges  
10 are expected to arise including capacity constraints, power quality  
11 issues, and adverse impacts on protection systems. Furthermore,  
12 decreases in DER hosting capacity will limit PG&E’s ability to support  
13 more DERs without infrastructure improvements. To address these  
14 issues, PG&E proposes to build a DERMS to complement the  
15 foundational technology improvements and grid management tools built  
16 by the ADMS Program.

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<sup>26</sup> A.18-12-009, HE 18: Exhibit (PG&E-7), Ch. 9, WP 9-79 to WP 9-82.

1 Informed by PG&E's experience implementing DERMS pilots via  
 2 EPIC projects 2.02<sup>27</sup> and 3.03,<sup>28</sup> this project will address near-term  
 3 challenges while also providing flexibility for an evolving future.

4 Specifically, PG&E proposes to build a DERMS that will deliver the  
 5 following capabilities:

- 6 • Monitoring, Dispatch, and Program Management of DER Systems –  
 7 DERMS will be a secure platform that enables the monitoring and  
 8 dispatch of both FTM, BTM, and aggregated DER assets with rules  
 9 based on program types. DERMS will provide new visibility into  
 10 DER status, flexibility, availability, and program-level insights, while  
 11 enabling visibility and control over the large population of smaller  
 12 DERs without SCADA telemetry.
- 13 • Full Integration with ADMS – DERMS will seamlessly integrate with  
 14 the ADMS, building on the integrated network model and grid  
 15 modeling capabilities provided by the core ADMS product.
- 16 • DER Interconnection and Market Participation Facilitation – DERMS  
 17 will enable more dynamic hosting capacity by managing constraints  
 18 on DERs including a limited generation profile,<sup>29</sup> and other  
 19 constraints under abnormal conditions. DERMS will also help  
 20 manage DER impacts at the Transmission and Distribution interface  
 21 including coordination of wholesale market participants on the  
 22 distribution system.

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<sup>27</sup> PG&E, EPIC 2.02 – Distributed Energy Resource Management System (Jan. 18, 2019), at <[https://www.pge.com/pge\\_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-2.02.pdf](https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-2.02.pdf)> (accessed May 23, 2021).

<sup>28</sup> PG&E's Application For Approval of Its 2018- 2020 Electric Program Investment Charge Investment Plan, A.17-04-028 (Apr. 28, 2017), at <[https://www.pge.com/pge\\_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/EPIC-3-Application-PGE.pdf](https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/EPIC-3-Application-PGE.pdf)> (accessed May 23, 2021).

<sup>29</sup> A limited generation profile is described in Issue 9 of D.20-09-035 (see Section 4.3.3). It provides the capability to limit a customer's generation based on a profile that changes temporarily. Decision link, at <<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M347/K953/347953769.PDF>> (accessed June 7, 2021).

- 1 • Operation of DER-Based Deferral Solutions – DERMS will increase  
 2 the efficiency of managing the dispatch, mitigations, and settlements  
 3 of projects participating in the DIDF and other alternatives to  
 4 conventional infrastructure investments. As the number of these  
 5 projects expand, one-off project management solutions will become  
 6 untenable and a platform-based solution will be essential.
- 7 • Enablement of DER-Based Resilience Solutions – DER-based  
 8 resilience solutions—such as third party and PG&E-operated  
 9 microgrids—are projected to grow as microgrids are increasingly  
 10 leveraged for resilience and PSPS impact mitigation. A  
 11 platform-based approach will help facilitate proper management and  
 12 operation of these systems and enable higher participation of DER  
 13 assets.

14 While PGE expects that portions of the functionalities described  
 15 above may be needed for isolated projects prior to the projected 2026  
 16 deployment date of DERMS, this project focuses on a platform-based  
 17 approach to address the expected growth and management of DERs  
 18 based on technological, consumer, and regulatory advances well into  
 19 the future.

20 The forecast for DERMS has both an expense and capital  
 21 expenditure component, and is summarized in Table 21-7, below. The  
 22 2023 forecast is higher than 2020 recorded costs because the DERMS  
 23 project is not scheduled to begin until 2023.

**TABLE 21-7**  
**DISTRIBUTED ENERGY RESOURCE MANAGEMENT SYSTEM**  
**RECORDED AND FORECAST COSTS**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Workpaper Reference
1	Capital (MWC 63)	.	–	–	\$975	\$4,005	\$20,565	\$26,438	WP 21-12, line 9.
2	Expense (MWC HG)	–	–	–	119	502	2,644	3,480	WP 21-5, line 10.
3	Total	–	–	–	\$1,094	\$4,507	\$23,209	\$29,918	

### 3. IGP IT Infrastructure

Deploying the new planning and operational technologies described in this chapter will substantially increase the volume of data traffic necessary to operate the electric system. It will also increase demand for low latency data transmission, which is necessary for real-time visibility and control of the grid. To satisfy these needs, PG&E requires modern, secure communications and computing infrastructure with adequate capacity, coverage, scalability, and resiliency. To this end, PG&E plans to continue several foundational investments to modernize and expand its IT infrastructure.<sup>30</sup>

These investments primarily involve PG&E's multi-purpose telecommunications network, which connects the people, information, devices, and autonomous systems essential to Company operations. Parts of that network currently rely on outdated technologies that were not designed to support the volume of traffic or quantity of devices now being deployed in the field. As the network has aged, many of its individual components are also at increasing risk of failure, which can lead to a loss of real-time visibility. The investments described below will enable PG&E to maintain adequate network reliability, meet increasing demand, and securely connect users and devices at locations across PG&E's service territory. In addition, investments in computing infrastructure will help ensure that the systems that receive and process data across the network can efficiently scale to meet future growth. PG&E uses a combination of Company-owned network assets, telephone company leases, and carrier technologies (e.g., cellular, satellite) to provide the capacity and resiliency that PG&E's operating technologies require.

These investments in IT infrastructure, which have applications and benefits beyond support for IGP, span several workstreams:

- Field Area Network (FAN) – This workstream will continue ongoing deployment of a multi-purpose wireless communications network that provides connectivity to PG&E's data network for field devices—

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<sup>30</sup> In the 2020 GRC, the forecast for this work was presented in HE-66: Exhibit (PG&E-7), Ch. 8, "Information Technology." For the 2023 GRC, recorded and forecast costs have been centralized in this chapter.

1 including automation devices, sensors, and mobile devices used by field  
2 personnel—within a several-mile radius of a target field location (such  
3 as a substation or service center). The FAN is a scalable and resilient  
4 mesh network designed with the capability to meet both current needs  
5 and emerging use cases for network connectivity in the field.

- 6 • SCADA Network Reliability Improvements – This workstream will  
7 continue ongoing work to modernize the architecture of PG&E’s legacy  
8 SCADA communications networks, which are approaching 30 years old,  
9 and address associated IT asset failure risks. The work will include the  
10 removal or replacement of obsolete and high-failure-rate equipment,  
11 unreliable leased wireline circuits, and alternating current-powered  
12 network components without battery back-ups, as well as deployment of  
13 secondary communication paths to critical sites and devices to improve  
14 resiliency and eliminate single points of failure in the SCADA  
15 communications network.
- 16 • Substation Converged Compute Platform – This workstream will  
17 continue ongoing work to pilot and deploy at select substations a  
18 modern, “cloud-like” infrastructure platform that will consolidate and  
19 standardize existing, physically separate equipment and supporting  
20 software into a smaller, shared physical footprint that can efficiently  
21 scale to support future automation and DER demand. This “converged”  
22 infrastructure will leverage a modern design similar to the private cloud  
23 infrastructure used in PG&E data centers, but it must be adapted to the  
24 unique operating environment of an electric substation.
- 25 • Data Center and Control Center Infrastructure Preparation – This  
26 workstream will continue ongoing work to support deployment of the  
27 ADMS platform at PG&E’s three DCCs and its integration with systems  
28 in PG&E data centers by enhancing communications networks at the  
29 DCCs, adding capacity to key fiber optic circuits, and deploying alternate  
30 communication paths to improve network resiliency and reduce the  
31 potential impact of asset failures. This workstream is currently  
32 forecasted to conclude in 2021.

33 The forecast for IGP IT Infrastructure, which has both an expense and  
34 capital expenditure component, is summarized in Tables 21-8 and 21-9,

1 below.<sup>31</sup> The 2023 forecast is lower than 2020 recorded costs because a  
 2 decrease in program activity associated with FAN, SCADA Network  
 3 Reliability Improvement, and Data Center and Control Center Infrastructure  
 4 is expected to outweigh increases in the Substation Converge Compute  
 5 Platform program activity.

**TABLE 21-8  
 IGP IT INFRASTRUCTURE  
 RECORDED AND FORECAST EXPENSE  
 (THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	Workpaper Reference
1	Expense (MWC JV)	\$739	\$1,130	\$2,300	\$2,300	WP 21-5, lines 15-18.

**TABLE 21-9  
 IGP IT INFRASTRUCTURE  
 RECORDED AND FORECAST CAPITAL  
 (THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Workpaper Reference
1	Capital (MWC 2F)	\$23,993	\$18,490	\$16,900	\$16,900	\$17,200	\$17,700	\$17,000	WP 21-12, lines 14-17.

#### 6 **4. Electric Emerging Technology Program**

7 The Electric Emerging Technology Program will identify, develop, and  
 8 ~~demonstrate emerging but unproven technologies to provide benefits to~~  
 9 ~~PG&E's electric customers and advance California energy policy objectives.~~  
 10 ~~This program will allow PG&E to continue its invaluable work in the~~  
 11 ~~Technology Demonstration and Deployment area of the EPIC Program in~~  
 12 ~~the event that PG&E is not authorized in the EPIC successor program~~  
 13 ~~rulemaking (Rulemaking (R.) 19-10-005) to continue as an EPIC~~  
 14 ~~administrator beyond the current EPIC 3 cycle. Current EPIC work will end~~  
 15 ~~by 2022, and PG&E's role in demonstrating emerging technologies will~~

---

<sup>31</sup> Certain costs presented in Tables 21-8 and 21-9 are associated with the Information Technology Asset Failure (ITAF) risk event, mitigation M005 – Multi-Faceted Mitigations described in Exhibit (PG&E-7), Ch. 8, Section B.2.

1 remain critical going forward, particularly in support of PG&E and the state's  
2 high-priority wildfire risk mitigation and clean energy goals. If the IOUs are  
3 authorized in R.19-10-005 to continue administering their respective EPIC  
4 Programs, PG&E will withdraw this program from consideration in the 2023  
5 GRC fund and administer a series of external innovation partnerships that  
6 will serve to keep PG&E informed of the external technology landscape and  
7 industry trends, and facilitate coordination with industry, academia, and  
8 other external groups to identify and apply technology solutions that address  
9 PG&E's greatest challenges.

10 The program has ~~three~~ two primary components:

- 11 • ~~Emerging Technology Projects~~ – Through these projects, PG&E will  
12 develop and demonstrate pre-commercial technologies or strategies at a  
13 scale sufficiently large and in conditions sufficiently reflective of  
14 anticipated actual operating environments to enable appraisal of their  
15 operational and performance characteristics and financial risks.  
16 Candidate projects and initiatives will be evaluated based on their  
17 expected furtherance of safety, reliability, resiliency, customer  
18 affordability, and renewable energy integration.
- 19 • External Innovation Partnerships – This area will cover a range of  
20 external partnerships and initiatives, including formal external innovation  
21 challenges, industry technology and vendor landscaping, participation in  
22 emerging technology consortia, and targeted partnerships with  
23 academia and national labs. Maintaining these types of targeted  
24 partnerships and initiatives will be critical to not only keeping PG&E  
25 appraised of technology trends and promising opportunities, but also  
26 enabling PG&E to influence other resources and sources of funding  
27 towards addressing the needs of California and PG&E's customers.
- 28 • Emerging Technology Program Innovation Partnership Administration –  
29 This area will create a central Program Management Office (PMO) to  
30 fund the internal staff that will administer the portfolio of emerging  
31 technology projects and external innovation partnerships. This PMO  
32 would be similar in structure to the centralized governance and enabling  
33 services in place for the current EPIC Program. The current EPIC  
34 Program caps administrative expenses at 10 percent of overall program

1 spend, and PG&E would similarly cap the expenditures for this Electric  
2 Emerging Technology Program.

3 The forecast for the Electric Emerging Technology Program is expense  
4 only, and is summarized in Table 21-10, below. The 2023 forecast is higher  
5 than 2020 recorded costs due to the initiation of the External Innovation  
6 Partnerships workstream beginning in 2023.

**TABLE 21-10**  
**ELECTRIC EMERGING TECHNOLOGY PROGRAM**  
**RECORDED AND FORECAST COSTS**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	Workpaper Reference
1	Expense (MWC AT)	-	-	-	\$2,056	WP 21-5, line 26.

## 7 **5. Elkhorn Battery Energy Storage System**

8 PG&E received approval by the CPUC's Resolution (Res.) E-4949 to  
9 design, permit, construct, and maintain the Elkhorn Battery Energy Storage  
10 System (Elkhorn BESS), a lithium-ion battery installation that will deliver  
11 182.5 megawatts of power at the point of interconnection at the  
12 Moss Landing Substation in Monterey County. The project is forecasted to  
13 be released to operations in July 2021 with an early 2022 forecasted project  
14 completion date. The Elkhorn BESS will be owned and operated by PG&E.

15 The Elkhorn BESS project is being developed via an engineering,  
16 procurement, and construction contract with Tesla, Inc.; the project is  
17 managed by EO. The project includes the installation of 256 Tesla  
18 Megapack battery units on 33 concrete slabs. Each unit houses batteries  
19 and associated equipment in a steel cabinet. Transformers and switchgears  
20 connect energy stored in the batteries with the 115 kilovolt transmission  
21 system. It will have the capacity to store and dispatch up to  
22 730 megawatt-hours of energy to the electrical grid at a maximum rate of  
23 182.5 megawatts for up to four hours during periods of high demand.

24 Without adding new fossil fuel resources to the grid, Elkhorn BESS will  
25 enhance reliability by addressing capacity deficiencies resulting from local  
26 load growth. The system will also participate in the CAISO markets,

1 providing energy and ancillary services, such as serving as an operating  
 2 reserve that can quickly be dispatched to facilitate sufficient capacity to the  
 3 CAISO-controlled grid. These services will help the state integrate  
 4 renewable resources, such as wind and solar, which are intermittent or  
 5 generate the most energy during times of low customer demand.

6 Per Res.E-4949, the Commission authorized PG&E to record the  
 7 revenue requirement based on actual costs up to the adopted cost forecast  
 8 associated with the project once the project achieved commercial operation  
 9 to the NSGBA. The resolution directed that the cost forecast be included in  
 10 the GRC, but the resulting revenue requirement transferred to the NSGBA  
 11 for inclusion in the New System Generation Charge and recovered in rates  
 12 consistent with the cost forecast via the Cost Allocation Mechanism for the  
 13 full useful life of the project using the net capacity cost calculation.

14 The public portion of the forecast for the Elkhorn BESS, which has both  
 15 an expense and capital expenditure component, is summarized in Tables  
 16 21-11 and 21-12, below.<sup>32</sup> The 2023 forecast is lower than 2020 recorded  
 17 costs because capital expenditure decreases associated with the end of  
 18 construction on the Elkhorn BESS more than outweigh expense increases  
 19 associated with the beginning of O&M on the completed project.

**TABLE 21-11  
 ELKHORN BATTERY ENERGY STORAGE SYSTEM  
 RECORDED AND FORECAST EXPENSE  
 (THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	Workpaper Reference
1	Expense (MWC AB)	-	-	CONF	CONF	WP 21-5, line 29.

<sup>32</sup> See Exhibit (PG&E-4), Appendix A for confidential Elkhorn costs.

**TABLE 21-12**  
**ELKHORN BATTERY ENERGY STORAGE SYSTEM**  
**RECORDED AND FORECAST CAPITAL**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	Workpaper Reference
1	Capital (MWC 3R)	\$86,080	CONF	CONF	–	–	–	–	WP 21-12, line 27. WP 21-12, line 30.
2	Capital (MWC 82)	41	121	–	–	–	–	–	
3	Total	\$86,121	CONF	CONF	–	–	–	–	

#### 1 **D. Estimating Methods**

2 PG&E uses a variety of estimating methods for projects within this chapter:

- 3 • Forecasts for IGP IT Infrastructure and Distribution Engineering Planning  
4 Tools work under MWC 2F and JV in this chapter were created using the  
5 standard estimating methods for technology project investments discussed  
6 in Exhibit (PG&E-7), Chapter 8. Historical spend patterns, subject matter  
7 expertise, and standard cost factors serve as primary inputs to the IT  
8 estimating tools used in this chapter to calculate labor and non-labor costs  
9 and document associated assumptions. Forecasts are sequenced to fit  
10 within high-level annual planning targets set by IT and Company leadership  
11 to align with strategic priorities. Refer to the project summary workpaper  
12 starting at WP 21-58 for more information on the specific estimating  
13 methods used for the IGP IT Infrastructure project, and the project summary  
14 workpaper starting at WP 21-35 for more information on the estimating  
15 methods used for non-DRP-driven Distribution Engineering Planning Tools;
- 16 • Forecasts for the “Release 1 (SCADA),” “ADMS Asset Data,” “ADMS  
17 Cybersecurity,” and “ADMS PMO” subcomponents of the ADMS project are  
18 the result of a detailed bottoms-up forecasting exercise by PG&E subject  
19 matter experts (SME), informed by insights on project cost gained through  
20 implementation to date. PG&E utilized an Association for the Advancement  
21 of Cost Engineering (AACE) Class 2 estimate for these subcomponents of  
22 the ADMS forecast due to the use of deterministic estimating methods and  
23 the presence of detailed engineering designs and resource/contracting  
24 plans. The forecast for the “Release 2 (OMS)” and “Release 3 (Advanced  
25 Apps)” portions of the ADMS project was developed by PG&E SMEs in

1 consultation with a third-party Systems Integrator with extensive experience  
2 implementing ADMS projects in North America. PG&E utilized an AACE  
3 Class 3 estimate for these subcomponents of the ADMS forecast due to the  
4 presence of a detailed scope of work and estimation method that was more  
5 deterministic than probabilistic;

- 6 • The DERMS program forecast was created by SMEs at PG&E in  
7 consultation with a third-party Systems Integrator using the assumptions  
8 outlined in WP 21-13. PG&E used an AACE Class 5 estimate because the  
9 project is in the early concept and planning phases;
- 10 • The CMEP program forecast for 2021 and 2022 was authorized in  
11 D.20-06-017 (p. 85). The 2023 forecast is the product of PG&E SME  
12 judgement of resources required to support an anticipated increase in  
13 microgrid project development activity;
- 14 • The DRP-related Distribution Engineering Planning Tools forecast was  
15 created by PG&E SMEs using a combination of vendor quotations and  
16 PG&E internal labor costs;
- 17 • The Distribution Deferral Non-Procurement Cost forecast was the product of  
18 PG&E SME judgement regarding the labor required to successfully  
19 complete the work;
- 20 • The Electric Emerging Technology Program forecast was created using the  
21 planned external innovation partnerships planned for 2022 as a benchmark;  
22 ~~and using PG&E's current annual expenditures on the EPIC Program as a~~  
23 ~~benchmark; and~~
- 24 • The Elkhorn Battery Energy Storage System forecast was authorized in  
25 Res.E-4949.

## 26 **E. Compliance with Prior Commission Decisions**

### 27 **1. Compliance with Section 5.2 of the GRC Settlement Agreement**

28 Section 5.2 of the 2020 GRC Settlement Agreement required PG&E to  
29 make an additional showing in its 2023 GRC testimony for deferred work  
30 that was previously requested and authorized based on representations that  
31 the work was needed to provide safe and reliable service. PG&E reviewed  
32 the Grid Modernization chapter of its 2020 GRC<sup>33</sup> and determined that no

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33 A.18-12-009, HE-17: Exhibit (PG&E-4), Ch. 19.

1 work met the criteria for deferred work as described in the Settlement  
2 Agreement.

## 3 **2. Other Compliance Items**

- 4 • D.18-03-023 outlined several content requirements for IOU Grid  
5 Modernization GRC filings. PG&E identifies the location within its filing  
6 where these content requirements are satisfied in WP Table 21-16.  
7 Furthermore, D.18-03-023 requires IOUs to provide tables  
8 demonstrating the location and cost of all Grid Modernization  
9 investments within the filing if they are not located within a single  
10 chapter. PG&E provides this information in WP Tables 21-14 and WP  
11 21-15;
- 12 • D.20-06-017 (p. 85) required PG&E's 2023 GRC to include a CMEP  
13 program evaluation that will enable the Commission to determine the  
14 efficacy of the program and whether funding should continue beyond  
15 2022. This program evaluation is located in Attachment A3 to this  
16 chapter; and
- 17 • D.20-12-005 (p. 308) required PG&E's 2023 GRC to include support for  
18 its proposed allocation of Grid Modernization costs. This discussion is  
19 included in Section A.3.c of this Testimony chapter.

## 20 **F. Balancing and Memorandum Accounts**

21 Portions of the forecast in this chapter are associated with the balancing or  
22 memorandum accounts listed below.

- 23 • Distributed Energy Resources Distribution Deferral Account (DERDDA) –  
24 This balancing account tracks non-procurement costs associated with DER  
25 contracts for distribution deferral, which are discussed in Section C.1.b.  
26 PG&E proposes to modify the DERDDA preliminary statement to include  
27 only incremental costs above the amounts ultimately adopted by the  
28 Commission;
- 29 • Avoided Costs Calculator Update Memorandum Account (ACCUMA) – This  
30 memorandum account tracks costs associated with updates to the Avoided  
31 Costs Calculator, which are discussed in Section C.1.b. ~~A discussion of the~~  
32 ~~reasonableness of the recorded costs in this account is located in the project~~

1 ~~summary for Distribution Deferral Non-Procurement Costs, which starts at~~  
2 ~~WP 21-43. PG&E proposes to continue recording to the ACCUMA;~~

- 3 • Distribution Resources Plan Tools Memorandum Account (DRPTMA) – This  
4 memorandum account tracks Distribution Engineering Planning Tool costs  
5 driven by DRP Compliance, which are discussed in Section C.1.a.

6 ~~A discussion of the reasonableness of recorded costs in this account is~~  
7 ~~located in the project summary for Distribution Engineering Planning Tools,~~  
8 ~~which starts at WP 21-35. PG&E proposes to continue to record amounts~~  
9 ~~incremental to the GRC in the DRPTMA;~~

- 10 • New System Generation Balancing Account (NSGBA) – This balancing  
11 account is used to record costs for the Elkhorn Battery Energy Storage  
12 System, which is discussed in Section C.5; and
- 13 • Microgrids Memorandum Account (MGMA) – This memorandum account is  
14 used to record cost for CMEP, which is discussed in Section C.1.c.

15 For further information about balancing or memorandum accounts, refer to  
16 Exhibit (PG&E-12), Chapter 7.

## 17 **G. Cost Tables**

18 The expense and capital forecasts for IGP and Grid Modernization  
19 (excluding the Elkhorn Battery Energy Storage System forecast in years  
20 2021-2023, which is presented in a confidential appendix)<sup>34</sup> are summarized in  
21 the following tables:

- 22 • Table 21-13 lists the expense MWCs, showing 2016 through 2020 recorded  
23 expenses and 2021 through 2023 forecast expenses; and
- 24 • Table 21-14 lists the capital MWCs, showing 2016 through 2020 recorded  
25 expenditures and 2021-2026 forecast expenditure.

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26 .

<sup>34</sup> See Exhibit (PG&E-4), Appendix A.

**TABLE 21-13**  
**JUNE 30, 2021 GRC FORECAST**  
**EXPENSE**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast			Workpaper Reference
			2016	2017	2018	2019	2020	2021	2022	2023	
1	AB	Misc Expense	-	-	\$484	\$2,003	\$3,320	\$3,926	\$4,135	\$10,015	WP 21-1, line 1.
2	AT	Emerging Technology	\$20,423	\$18,907	14,651	8,004	14,609	16,158	16,653	17,174	WP 21-1, line 2.
3	HG	Elec Trans Ops Engr & Tech	-	453	3,374	3,010	5,154	5,424	2,287	15,541	WP 21-1, line 3.
4	IG	Manage Var Bal Acct Processes	-	71	149	236	686	4,013	5,596	3,026	WP 21-1, line 4.
5	JV	Maintain IT Apps & Infra			1,404	524	1,429	1,345	2,500	3,309	WP 21-1, line 5.
6		Total	\$20,423	\$19,431	\$20,062	\$13,778	\$25,198	\$30,867	\$31,171	\$49,065	

**TABLE 21-14**  
**FEBRUARY 25, 2022 UPDATED GRC FORECAST**  
**EXPENSE**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast			Workpaper Reference
			2016	2017	2018	2019	2020	2021	2022	2023	
1	AB	Misc Expense	-	-	\$484	\$2,003	\$3,320	\$3,926	\$4,135	\$10,015	WP 21-1, line 1.
2	AT	Emerging Technology	\$20,423	\$18,907	14,651	8,004	-	-	-	2,056	WP 21-1, line 2.
3	HG	Elec Trans Ops Engr & Tech	-	453	3,374	3,010	5,154	5,424	2,287	15,541	WP 21-1, line 3.
4	IG	Manage Var Bal Acct Processes	-	71	149	236	686	4,013	5,596	3,026	WP 21-1, line 4.
5	JV	Maintain IT Apps & Infra			1,404	524	1,429	1,345	2,500	3,309	WP 21-1, line 5.
6		Total	\$20,423	\$19,431	\$20,062	\$13,778	\$10,589	\$14,708	\$14,518	\$33,947	

(PG&E4)

**TABLE 21-15  
CAPITAL  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast					Workpaper Reference	
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		2026
1	21	Misc. Capital	-	-	\$1,114	\$2,116	\$395	\$2,882	\$3,083	\$2,237	\$1,852	\$1,902	-	WP 21-12, line 22.
2	2F	IT Capital	-	-	12,077	16,759	26,724	19,540	17,900	20,369	19,086	19,695	17,000	WP 21-12, line 19.
3	3M	Install/Repl Var Bal Acct	\$10,151	\$(5)	-	-	-	-	-	-	-	-	-	WP 21-12, line 25.
4	3R	Energy Storage Capital	-	-	-	15,460	86,080	CONF	CONF	-	-	-	-	WP 21-12, line 28.
5	63	Electric Distribution Operations	-	-	5,048	12,209	44,373	81,885	126,880	109,049	68,042	20,565	26,438	WP 21-12, line 10.
6	82	Technology TO-EGI/WRO/SI	-	-	11	67	41	121	-	-	-	-	-	WP 21-12, line 31.
7		Total	\$10,151	\$(5)	\$18,250	\$46,610	\$157,613	\$104,428	\$147,863	\$131,655	\$88,981	\$42,163	\$43,438	

(PG&E4)

**PACIFIC GAS AND ELECTRIC COMPANY  
2023 GENERAL RATE CASE**

Testimony:  Workpapers:  SOQ:   
 Exhibit Number: 4 Chapter Number: 21  
 Chapter Title: Integrated Grid Platform and Grid Modernization Plan  
 Witness Name: Elaine Reusing and Quinn Nakayama

Page No. in Errata 1	Line No.	Item	As Filed	As Corrected
<b>Errata as of February 25, 2022</b>				
21-3	19	Scope and Purpose		This chapter was updated as part of the February 25, 2022 filing to provide an update for PG&E's 10,000 mile Electric Distribution Undergrounding Program. For this chapter the update is not related to PG&E's undergrounding program, it is to remove the EPIC program funding from the GRC as described in PG&E's opening testimony, pending renewal of the EPIC program.
21-5	4	Table 21-1	Tracks expenses associated with Research and Development (R&D) including Ch. 21 recorded costs for the Electric Program Investment Charge (EPIC) Program and forecast for the Electric Emerging Technology Program.	Tracks expenses associated with emerging technology activities, including the forecast for the Electric Emerging Technology Program.
21-7	Figure 21-1	N/A	2020 Recorded Adjusted \$25,198, Distribution Planning \$9,745, Distribution Operations \$10,387, IT Infrastructure \$1,169, Emerging Technology \$2,566, 2023 Forecast \$49,065	2020 Recorded Adjusted \$10,589, Distribution Planning \$9,745, Distribution Operations \$9,995, IT Infrastructure \$1,561, Emerging Technology \$2,056, 2023 Forecast \$33,947

Page No. in Errata 1	Line No.	Item	As Filed	As Corrected
21-9	29	N/A	Continuation of PG&E's electric technology R&D work.	Continuation of PG&E's electric emerging technology work.
21-10	1	N/A	PG&E's Grid Modernization forecast builds on past investments and R&D and takes a cost-conscious, conservative approach to create a foundation for modern grid operations.	PG&E's Grid Modernization forecast builds on past investments and technology demonstrations and takes a cost-conscious, conservative approach to create a foundation for modern grid operations.
21-11	8	N/A	Long-Term/R&D – The Emerging Electric Technology Program will assist DER integration capability in the longer term through field demonstration of emerging technologies, a vital first step to scaling any new technology within core Company operations.	<u>Long-Term/Emerging Technology – The Emerging Electric Technology Program</u> will assist DER integration capability in the longer term through a series of external innovation partnerships that will keep PG&E informed of the external technology landscape and industry trends, and facilitate coordination with external groups to identify technology solutions that address PG&E's greatest challenges.
21-11	18	N/A	R&D	innovation partnerships
21-11	12	N/A	These benefits include improved cybersecurity and reliability performance, increased operational efficiency, integration of mission critical operational tools, reduced technical debt, improved safety, more targeted and efficient Public Safety Power Shutoffs (PSPS), and non-DER-related R&D in areas such as safety, reliability, resiliency, and affordability.	These benefits include improved cybersecurity and reliability performance, increased operational efficiency, integration of mission critical operational tools, reduced technical debt, improved safety, more targeted and efficient Public Safety Power Shutoffs (PSPS), and non-DER-related innovation partnerships in areas such as safety, reliability, resiliency, and affordability.

Page No. in Errata 1	Line No.	Item	As Filed	As Corrected
21-12	1	N/A	The Electric Emerging Technology Program is managed by the Emerging Technology Strategy and Programs team within PG&E's Asset Knowledge Management organization, the same team that currently manages PG&E's EPIC Program; and	The Electric Emerging Technology Program is managed by the Emerging Technology Strategy and Programs team within PG&E's Asset Knowledge Management organization; and

Page No. in Errata 1	Line No.	Item	As Filed	As Corrected
21-27	7	N/A	<p>The Electric Emerging Technology Program will identify, develop, and demonstrate emerging but unproven technologies to provide benefits to PG&amp;E's electric customers and advance California energy policy objectives. This program will allow PG&amp;E to continue its invaluable work in the Technology Demonstration and Deployment area of the EPIC Program in the event that PG&amp;E is not authorized in the EPIC successor program rulemaking (Rulemaking (R.) 19-10-005) to continue as an EPIC administrator beyond the current EPIC 3 cycle. Current EPIC work will end by 2022, and PG&amp;E's role in demonstrating emerging technologies will remain critical going forward, particularly in support of PG&amp;E and the state's high-priority wildfire risk mitigation and clean energy goals. If the IOUs are authorized in R.19-10-005 to continue administering their respective EPIC Programs, PG&amp;E will withdraw this program from consideration in the 2023 GRC.</p>	<p>The Electric Emerging Technology Program will fund and administer a series of external innovation partnerships that will serve to keep PG&amp;E informed of the external technology landscape and industry trends, and facilitate coordination with industry, academia, and other external groups to identify and apply technology solutions that address PG&amp;E's greatest challenges.</p>
21-28	6	N/A	<p>The program has three primary components:</p>	<p>The program has two primary components:</p>

Page No. in Errata 1	Line No.	Item	As Filed	As Corrected
21-28	7		<p>Emerging Technology Projects – Through these projects, PG&amp;E will develop and demonstrate pre-commercial technologies or strategies at a scale sufficiently large and in conditions sufficiently reflective of anticipated actual operating environments to enable appraisal of their operational and performance characteristics and financial risks. Candidate projects and initiatives will be evaluated based on their expected furtherance of safety, reliability, resiliency, customer affordability, and renewable energy integration.</p>	
21-28	15	N/A	<p><u>External Innovation Partnerships</u> – This area will cover a range of external partnerships and initiatives, including external innovation challenges, industry technology and vendor landscaping, participation in emerging technology consortia, and targeted partnerships with academia and national labs.</p>	<p><u>External Innovation Partnerships</u> – This area will cover a range of external partnerships and initiatives, including formal external innovation challenges, industry technology and vendor landscaping, participation in emerging technology consortia, and targeted partnerships with academia and national labs.</p>

Page No. in Errata 1	Line No.	Item	As Filed	As Corrected
21-28	24	N/A	<p><u>Emerging Technology Program Administration</u> – This area will create a central Program Management Office (PMO) to administer the portfolio of emerging technology projects and external innovation partnerships. This PMO would be similar in structure to the centralized governance and enabling services in place for the current EPIC Program. The current EPIC Program caps administrative expenses at 10 percent of overall program spend, and PG&amp;E would similarly cap the expenditures for this Electric Emerging Technology Program.</p>	<p><u>Innovation Partnership Administration</u> – This area will fund the internal staff that will administer the portfolio of external innovation partnerships.</p>
21-28	32	N/A	<p>The forecast for the Electric Emerging Technology Program is expense only, and is summarized in Table 21-10, below. The 2023 forecast is higher than 2020 recorded costs due to the initiation of the External Innovation Partnerships workstream beginning in 2023.</p>	<p>The forecast for the Electric Emerging Technology Program is expense only, and is summarized in Table 21-10, below.</p>

Page No. in Errata 1	Line No.	Item	As Filed	As Corrected
21-29	1	Table 21-10, 2023 Forecast	2020 Recorded \$14,609, 2021 Forecast \$16,158, 2022 Forecast \$16,653, 2023 Forecast \$17,174	2020 Recorded \$-, 2021 Forecast \$-, 2022 Forecast \$-, 2023 Forecast \$2,056
21-32	20	Estimating Methods	The Electric Emerging Technology Program forecast was created using PG&E's current annual expenditures on the EPIC Program as a benchmark; and	The Electric Emerging Technology Program forecast was created using the planned external innovation partnerships planned for 2022 as a benchmark; and
21-35	2	Table 21-13	<u>R&amp;D</u>	Emerging Technology
21-35	2	New Table (21-14)	2020 Recorded \$14,609, 2021 Forecast \$16,158, 2022 Forecast \$16,653, 2023 Forecast \$17,174	2020 Recorded \$-, 2021 Forecast \$-, 2022 Forecast \$-, 2023 Forecast \$2,056
21-36	N/A	Table 21-14	Table 21-14	Table 21-15

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 21**  
**ATTACHMENT A**  
**GRID MODERNIZATION PLAN – 10 YEAR VISION**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 21  
ATTACHMENT A  
GRID MODERNIZATION PLAN – 10 YEAR VISION

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PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 21  
ATTACHMENT A  
GRID MODERNIZATION PLAN – 10 YEAR VISION

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1                                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                                   **CHAPTER 21**  
3                                   **ATTACHMENT A**  
4                                   **GRID MODERNIZATION PLAN – 10 YEAR VISION**

5   **A. Introduction**

6           Pacific Gas and Electric Company’s (PG&E or the Company) 2023 General  
7   Rate Case (GRC) is required to include PG&E’s 10-Year Vision for Grid  
8   Modernization.<sup>1</sup> In Decision (D.) 18-03-023, for the Order Instituting Rulemaking  
9   (OIR) Regarding Policies, Procedures and Rules for Development of Distribution  
10   Resources Plan (DRP) pursuant to Public Utilities Code Section 769, the  
11   California Public Utilities Commission (CPUC or Commission) established a  
12   working definition of grid modernization centered on the cost-effective integration  
13   of Distributed Energy Resources (DER) into the distribution system, consistent  
14   with the goal of yielding net ratepayer benefits.<sup>2</sup> In addition, D.18-03-023  
15   recognized that there are grid modernization-related investments that are  
16   unrelated to DER integration but still necessary to improve safety and reliability  
17   of the grid.<sup>3</sup>

18           PG&E first filed a 10-Year Vision for Grid Modernization in 2018 as part of  
19   its 2020 GRC application (2020 GRC 10-Year Vision).<sup>4</sup> Technological, climate,  
20   policy, and market forces have evolved significantly since that filing and PG&E’s  
21   framework for defining its vision has evolved to reflect the new landscape. The  
22   context of PG&E’s 2020 GRC 10-Year Vision, and the evolution of PG&E’s  
23   vision since then, are described in Section B.

24           PG&E’s updated 10-year vision for Grid Modernization for 2023 GRC is  
25   summarized in Section C. The key themes driving PG&E’s current grid  
26   modernization vision are described in Section D. Sections E through H discuss  
27   the specific elements of the vision as they relate to the four components of the  
28   Integrated Grid Platform (IGP) organizing framework presented in PG&E’s 2020

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1   D.18-03-023, pp. 34-35, Ordering Paragraph (OP) 4.

2   D.18.03-023, p. 33, OP 1.

3   D.18.03-023, p. 5.

4   A.18-12-009, HE-17: Exhibit (PG&E-4), Ch. 19, Attachment A.

1 GRC 10-Year Vision: grid infrastructure, system monitoring and management,  
2 DER grid services, and distribution markets.

3 **B. Context for PG&E’s Vision**

4 The 2020 GRC 10-Year Vision focused primarily on grid modernization  
5 associated with integrating DERs on PG&E’s system. Specifically, that  
6 document addressed:

7 ... PG&E’s grid modernization vision to improve and enhance the safe and  
8 reliable planning and operations of the distribution grid for DERs already  
9 interconnected to the distribution grid, as well as for forecast DERs given  
10 current growth trends.<sup>5</sup>

11 The 2020 GRC 10-Year Vision was organized around the concept of the  
12 IGP pyramid, which describes four layers of grid capabilities of increasing  
13 sophistication: (1) grid infrastructure, (2) system monitoring and management,  
14 (3) DER grid services, and (4) distribution markets. The primary focus of the  
15 IGP work described in the 2020 GRC 10-Year Vision was on the second and  
16 third layers: building the foundational system monitoring and management  
17 capabilities to enable DER grid services.

18 The 2020 GRC 10-Year Vision emphasized California’s “changing energy  
19 landscape”—including decarbonization policies, rapidly advancing technology  
20 effectiveness, and increased customer engagement and choice.<sup>6</sup> The  
21 document also highlighted the increasing complexity of operating the grid due to  
22 the integration of DERs, changing usage patterns, and climate change.<sup>7</sup> These  
23 challenges have continued to evolve, in many cases at an accelerated pace, and  
24 new challenges have emerged. These challenges—including the dramatic  
25 escalation of wildfire ignition risk due to California’s climate, aggressive state  
26 decarbonization policies, and increased adoption of electric vehicles—have  
27 expanded the landscape and use cases for grid modernization. PG&E’s grid  
28 modernization vision must be updated to incorporate the physical infrastructure  
29 and technical capabilities necessary to manage the current landscape.

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5 A.18-12-009, HE-17: Exhibit (PG&E-4), p. 19-AtchA-1, lines 17-20.

6 A.18-12-009, HE-17: Exhibit (PG&E-4), p. 19-AtchA-5, line 10 to p. 19-AtchA-7, line 10.

7 A.18-12-009, HE-17: Exhibit (PG&E-4), p. 19-AtchA-5, line 10 to p. 19-Atch-12, line 20.

1 **C. Summary: PG&E's 10-Year Vision for Grid Modernization**

2 PG&E has observed meaningful shifts in the public policy, market,  
3 economic, and technological trends that were articulated in its 2020 GRC  
4 10-Year Vision. These changes have led PG&E to identify a set of key themes  
5 which PG&E anticipates will impact its grid in the coming decade; these themes  
6 are multi-faceted and update the 2020 GRC 10-Year Vision's primary focus on  
7 customer adoption of DERs. For example, the rapid emergence of tangible  
8 effects of climate change in the form of wildfire risk and extreme heat events—  
9 as well as the potential growth in other, currently-less-prevalent climatic forces—  
10 have placed an increased focus on the core electric service principles of  
11 reliability and resiliency as they relate to the integration of DERs.

12 In addition to grid reliability and resiliency, California's policymakers  
13 continue to adopt and refine ambitious climate targets which require  
14 cost-effective decarbonization of all sectors of the state's economy, including  
15 electric generation, transportation, and buildings. End users of electricity are  
16 highly engaged in their energy services, and PG&E's customers have potential  
17 alternatives they can explore to their traditional energy choices: electric  
18 vehicles, behind-the-meter solar and storage, participation in new wholesale  
19 markets via DER aggregators, as well as the ability to develop multi-customer  
20 microgrids for resiliency.

21 However, while the specific use cases on the grid continue to evolve,  
22 PG&E's vision for how the electric grid itself will evolve in the coming decade  
23 remains consistent and well aligned with the vision articulated in the 2020 GRC  
24 10-Year Vision. While the specific use cases on the grid continue to evolve,  
25 PG&E envisions a 10-year period which is a continuation of the vision described  
26 in its 2020 GRC—bolstering and reinforcing its grid infrastructure; deploying  
27 sophisticated system monitoring and management capabilities; and developing  
28 capabilities to plan, monitor, and control DERs to provide grid services—which  
29 maps to the first three layers of the IGP pyramid.

30 DER technology penetration and effectiveness continue to increase across  
31 the service territory. These DERs are increasingly able to provide cost-effective  
32 services to customers, transmission and distribution (T&D) grid services, and  
33 services to the wholesale energy market which can help meet the various  
34 climate challenges and state policy goals of today and the future. In order to

1 access this potential, PG&E will need to continue to implement cost-effective  
2 investments in grid infrastructure, communication infrastructure, cybersecurity,  
3 and software platforms to ensure that the management and control of such  
4 technologies can provide affordable, safe, and reliable services to the grid.

5 As noted in the 2020 Grid Modernization Vision, to manage the broad suite  
6 of forces impacting the grid, PG&E will need to develop a nimble and dynamic  
7 electric grid that can provide granular visibility and control of supply and demand  
8 throughout the system. PG&E will need to reinforce its physical infrastructure to  
9 accommodate evolving environmental conditions affecting DER integration.  
10 Additionally, new load from electric vehicle (EV) charging and building  
11 electrification DERs will necessitate new T&D capacity and load control  
12 functionality. The continued rise of DERs in response to declining technology  
13 costs and policy and resiliency drivers will necessitate a new operational  
14 paradigm of increased visibility, control, and automation. PG&E will continue to  
15 develop this operational toolkit over the coming decade as its investments in  
16 situational awareness and control will enable a suite of new advanced tools and  
17 sophisticated digital functionality. Supply will continue to evolve within PG&E's  
18 system and PG&E anticipates that a significant portion of electricity supply may  
19 move increasingly "downstream" (i.e., located at the substation or distribution  
20 levels, rather than the transmission level). PG&E does not anticipate making  
21 substantial investments in advanced distribution markets (e.g., a peer-to-peer  
22 marketplace) in the next 10 years except pursuant to specific DER commercial  
23 market developments, which may cause increased customer demand for such  
24 peer-to-peer services.

25 To achieve this vision, PG&E will need to develop and deploy a suite of  
26 infrastructure improvements and new capabilities that are responsive to  
27 developments in DER markets, products, and services. This suite can be  
28 organized into three time scales: near-term, medium-term, and long-term.

29 **Near-term:** A need to implement these infrastructure improvements and  
30 new capabilities exists today. Work has already begun or will begin soon,  
31 including forecasts in the 2023 GRC. Examples of near-term applications  
32 include:

- 1 • The hardening of electric T&D assets to mitigate risk of wildfire ignition from  
2 PG&E equipment failure;<sup>8</sup>
- 3 • Installation of foundational communications infrastructure to enable more  
4 advanced infrastructure and new capabilities;
- 5 • Advanced distribution planning tools which enable scenario planning and  
6 time series analyses of distribution system conditions to forecast distribution  
7 planning needs;
- 8 • Tools for customers and grid planners to identify optimal locations for siting  
9 DERs;
- 10 • Situational awareness enabled by the Advanced Distribution Management  
11 System (ADMS); and
- 12 • Monitoring and control of DERs enabled by the Distributed Energy Resource  
13 Management System (DERMS).

14 **Medium-term:** These infrastructure improvements and capabilities are  
15 likely to be required within the coming decade if DER markets and services  
16 continue to develop at their current pace. PG&E is taking preparatory steps to  
17 build the foundation for future deployment. Examples of medium-term  
18 applications include:

- 19 • Electric T&D capacity upgrades (including conductors, transformers, etc.) to  
20 accommodate load growth resulting from new EV charging and building  
21 electrification loads;
- 22 • Mass proliferation of line sensors to understand the real-time (RT) status of  
23 T&D lines (e.g., phasor measurement units);
- 24 • Rapid scaling of asset sensors, including nodes measuring asset health  
25 (e.g., asset operating temperatures);
- 26 • Deployment of smart switches within PG&E's system to enable the  
27 operation of multi-customer microgrids and to ensure reliability during  
28 climate events;
- 29 • Strategic placement of smart inverters and other voltage and frequency  
30 regulation technologies at the distribution grid edge ("synthetic inertia");

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<sup>8</sup> For further details of PG&E's system hardening to mitigate Wildfire risk, see Exhibit (PG&E-4), Ch. 4.

- 1 • Automation of equipment to enable passive operation of distribution system  
2 (i.e., operators not *actively operating* system in RT);
- 3 • Sophisticated models to forecast distribution load conditions on sub-annual  
4 increments and/or at a hyper-localized level;
- 5 • Secure communications connections to thousands of additional endpoints  
6 for monitoring and control of customer-sited DERs and controllable loads;
- 7 • Proliferation of communications and controls to manage sections of the  
8 distribution system that can island as a microgrid during larger grid outages;  
9 and
- 10 • Volt-Var Optimization.

11 **Long-term:** As of today, PG&E does not anticipate these infrastructure  
12 improvements and new capabilities warranting investment in the next decade.  
13 However, these trends will be monitored by PG&E as evolving conditions could  
14 quickly justify accelerated deployment (i.e., migrating from long-term to the  
15 near- or medium-term categories). Examples of long-term applications include:

- 16 • Distribution level market optimization and settlement technology.

17 Given the addition and acceleration of trends since PG&E drafted its 2020  
18 GRC 10-Year Vision, PG&E has developed an updated framework for  
19 organizing and responding to the impacts of various climate, policy, market, and  
20 technological forces on the grid consistent with the foundational framework in  
21 the 2020 GRC and the overall priorities of its 2023 GRC. This framework allows  
22 PG&E to identify key themes which emerge as a result of the intersection of  
23 these forces. These key themes are described in greater detail in Section D  
24 below. The implications of these key themes for the electric grid and PG&E's  
25 vision for how the grid should evolve to manage these key themes are described  
26 in Sections E through H of this document, organized according to the four layers  
27 of the IGP pyramid.

28 Lastly, PG&E notes that discussion of spending requirements to support its  
29 10-Year Grid Modernization Vision beyond the current GRC cycle must be  
30 qualitative in nature due to the impracticality of developing detailed cost  
31 estimates for work that is not yet scoped and not scheduled to begin for more  
32 than five years.

## 1 D. Key Themes

2 PG&E's electric grid is facing an evolving set of key themes driven by  
3 changes in technology, climate, policy, and the market.

4 **Technological Drivers** include adoption of behind-the-meter Photovoltaic  
5 and storage (either separately, or in tandem), EV, front-of-the-meter storage,  
6 building electrification, and controllable loads.

7 **Climate Drivers** include wildfire risk and mitigations (e.g., Public Safety  
8 Power Shutoff (PSPS)), extreme heat, drought, extreme storms, climate  
9 migration, and sea level rise.

10 **Policy Drivers** include state policies on renewable generation and carbon  
11 neutrality (e.g., SB 100), electric vehicles, Community Choice Aggregation,  
12 building codes and standards, the net energy metering (NEM) program,  
13 evolutions in rate design, and housing policy that will affect population density  
14 and migration.

15 **Market Forces** include the incentives provided for load management which  
16 dictate how customers will interact with the grid, and therefore the needed grid  
17 architecture (e.g., directly participate in the California Independent System  
18 Operator (CAISO) market and export onto the distribution system or remain one  
19 way passive customers that choose to use DERs for retail rate minimization).

20 The confluence of these forces has produced a set of key themes that have  
21 informed PG&E's vision for grid modernization.

### 22 1. Decarbonizing Electric Supply

23 California is a global leader in decarbonization policy. In order to meet  
24 the state's aggressive policy goals, including but not limited to former  
25 Governor Jerry Brown's Executive Order mandating carbon neutrality in  
26 California by 2045, PG&E must be at the forefront of decarbonization  
27 efforts.<sup>9</sup> Carbon neutrality is likely to require significant investments in clean  
28 generation. In the event these resources come from out of state (e.g., wind  
29 from the Mountain West region), new interstate transmission capacity may  
30 be required.

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9 Governor's Executive Order No. B-55-18 (Sept. 10, 2018).

## 2. DER Adoption for PSPS Resiliency

As a result of the increased frequency of PSPS events, many of PG&E's customers have pursued self-generation as a means for ensuring reliability. The installation of behind-the-meter distributed generation technologies like solar, fuel cells, and diesel or natural gas-fired generators allow customers to generate and—when paired with battery storage—store electric energy independent of the conventional distribution grid during PSPS events or other grid disruptions.

PG&E has observed a significant increase in distributed generation interconnections in recent years. Additionally, PG&E has observed an increase in customers pairing behind-the-meter solar applications with battery storage. While multiple factors contributed to this adoption, PG&E believes that customers' desire for PSPS resiliency meaningfully contributed to these increases. This theme will drive DER growth, necessitating new infrastructure and capabilities in the electric distribution system.

## 3. Adoption of Multi-Customer Microgrids Supplied by DERs for Resiliency and Local Control

In recent years, PG&E has observed a growing interest in multi-customer microgrids in its service territory. Customers have begun to explore multi-customer microgrids as a form of energy resiliency in response to the uncertainty surrounding the potential long-term impacts of climate change, extreme weather, and PG&E's PSPS program. In other cases, customer groups have sought to deploy multi-customer microgrids to secure more independent and localized control over their electricity. PG&E expects that this trend will continue in the coming decade, necessitating new grid infrastructure to accommodate the growth of microgrids.

For example, PG&E has developed the Community Microgrid Enablement Program to help facilitate multi-customer microgrid adoption for resiliency concerns. While the community may own the generation resources in these microgrids, PG&E acts as the distribution system operator and is responsible for providing safe and reliable electricity to its customers during both grid-connected and islanded modes. This arrangement requires enhanced visibility and RT switching operations, enabling rapid isolation and reconnection of grid segments.

#### 4. Load Growth from Electrification

One of the key foundational principles of California’s decarbonization strategy is the electrification of loads previously served by fossil fuels (i.e., replacing these high-emitting fuels with clean electricity). Two sectors are the primary focus of California’s electrification efforts: transportation and buildings.

Transportation is the sector of California’s economy with the most greenhouse gas (GHG) emissions. Tailpipe emissions make up 41 percent of California’s GHG emissions, climbing to over 50 percent when fuel extraction and refining are considered. In order to transition the state’s transportation sector towards EVs to begin offsetting these transportation emissions, California has adopted a suite of policies aimed at promoting the adoption of EVs (e.g., Zero Emission Vehicle Standard, Clean Vehicle Rebate Program, Advanced Clean Trucks). Most recently, in 2020, Governor Newsom called for 100 percent of in-state sales of new passenger cars and trucks to be zero-emission by 2035 and for medium and heavy-duty trucks operating in the state to be zero-emission by 2045.<sup>10</sup> The rapid adoption of EVs necessary to meet this target is likely to drive increased electric demand, both in the form of peak load (megawatt (MW)) and total energy delivered (megawatt-hour (MWh)).

Momentum behind the electrification of buildings has also grown significantly since PG&E filed its 2020 GRC application. Since 2019, a number of cities and communities have passed local codes and standards which promote the electrification of building energy consumption, including space and water heating, cooking, and other end uses. PG&E became the first dual-fuel utility in the United States to issue public support for all-electric new construction, with a public statement backing Berkeley City Council’s ordinance prohibiting natural gas infrastructure in new buildings. Following Berkeley’s measure, approximately 50 additional jurisdictions across PG&E’s service territory have already passed or are actively considering local policies to require or give preference to all-electric or partially-electric new construction.

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<sup>10</sup> Governor’s Executive Order No. N-79-20 (Sept. 23, 2020).

1           The adoption of all-electric buildings will also drive increased electric  
2 load (MW) and energy use (MWh). The scale of these impacts, as well as  
3 the impacts of EV adoption, is still being studied.

#### 4       **5. DERs to Mitigate Wildfire Risk**

5           A source of wildfire ignition risk related to PG&E's system is the failure  
6 of overhead electric distribution and transmission equipment. While  
7 underground distribution systems tend to predominate in dense urban areas  
8 and newer suburbs, overhead systems have been preferred in other  
9 locations because they are far less costly to construct and maintain.  
10 However, overhead wires have a much higher risk of environmental  
11 interaction than underground wires. Animals and vegetation can interact  
12 with distribution equipment and lead to detrimental effects, such as outages  
13 and wildfire ignition risk during certain weather conditions.

14           Given the increasing wildfire risk in PG&E's service territory and the  
15 relationship between overhead asset failure and wildfire ignition, PG&E  
16 anticipates increased interest in leveraging DERs in lieu of conventional  
17 electric delivery investments. DERs like aggregated behind-the-meter  
18 generation and front-of-the-meter storage will become more attractive in  
19 California's market due to their ability to significantly decrease ignition risk.  
20 One example of this trend is PG&E's Remote Grid initiative, which seeks to  
21 serve customers in remote High Fire Threat District areas via standalone  
22 power systems, rather than conventional distribution service.

#### 23       **6. Designing a System with Resiliency to Acute Climate Events**

24           On August 14th and 15th, 2020, the CAISO was forced to implement  
25 rolling blackouts in response to extreme heat conditions. For several days  
26 after that, CAISO issued warnings that demand was projected to exceed  
27 supply in light of the continued heat wave. Fortunately, California utilities,  
28 with the cooperation of large facilities and state buildings, were collectively  
29 able to manage demand to ensure blackouts were not necessary through  
30 the remainder of the heat event. Following these events, CAISO, CPUC,  
31 and the California Energy Commission (CEC) issued a *Final Root Cause*  
32 *Analysis*, which determined that extreme weather conditions, existing

1 resource adequacy and planning processes, and market practices were the  
2 three primary drivers of the blackout events.<sup>11</sup>

3 The state's needs for increased electricity supply for reliability will  
4 certainly result in the procurement of additional supply-side and  
5 demand-side DERs to meet demand during extreme weather events. The  
6 report signaled that the agencies would continue to explore how to enable  
7 new resources *beyond* large-scale in-state generation, including batteries,  
8 imports from neighboring states, and demand response (DR) and many  
9 others. As a result, it is not yet clear what form this procurement will take  
10 over the course of the next decade. This produces uncertainty for PG&E's  
11 electric grid, as new capacity or other reliability technology may be required  
12 to ensure deliverability of new supply resources to customers.

13 Beyond supply-related issues, the physical operation of the grid has  
14 been impacted by the effect of increased heat on the grid's physical assets.  
15 As the climate becomes increasingly harsh, weatherization practices must  
16 be implemented to improve asset resiliency to climate change. Predicted  
17 future weather conditions must be considered for all new and existing  
18 electric delivery assets.

## 19 **7. Load Management and DER Enablement**

20 PG&E defines load management as all of the policy tools available to  
21 shape customer demand.<sup>12</sup> California currently has three primary pathways  
22 for enabling DER participation in markets.

23 The first pathway is through customer incentive or tariffed programs  
24 which incentivize the adoption of behind-the-meter DERs on a  
25 single-customer basis (e.g., SGIP or NEM). This is the most common  
26 approach today, and these programs are unlikely to require significant  
27 overhauls of the status quo grid architecture.

28 The second pathway is real-time pricing (RTP). There are multiple  
29 forums in which RTP is currently being considered by California energy

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11 See CEC, et al., Final Root Cause Analysis (Jan. 13, 2021), at  
<<http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf>> (as of June 7, 2021).

12 Examples include, but are not limited to, signals and technology deployment through incentives (e.g., SGIP) or standards (e.g., Title 24).

1 stakeholders (e.g., CEC's Load Management OIR which is currently  
2 proposing that utilities offer all customer classes an opt-in hourly or  
3 sub-hourly real time rate by Q1 2023).<sup>13</sup> While RTP would necessitate  
4 upgrades in utility communications and billing systems, as currently  
5 proposed, PG&E does not foresee significant modifications to the status quo  
6 grid architecture. PG&E recently proposed real time rate pilots for  
7 Commercial Electric Vehicles (proposed in Application (A.) 20-10-011),  
8 Commercial and Industrial customers (proposed in A.19-11-019), and rate  
9 design research for Residential and Agricultural customers (proposed in  
10 A.19-11-019).

11 The third pathway is direct market participation. CAISO has two  
12 agreements that allow DERs to aggregate and directly participate in the  
13 wholesale market. The first model, the Demand Response Provider (DRP)  
14 Agreement, allows aggregated DERs to provide energy and ancillary  
15 services to CAISO's wholesale market in the form of load reduction using  
16 either CAISO's Proxy Demand Response model or CAISO's Reliability  
17 Demand Response Resource model. California has relied on DR as a  
18 critical tool in the electric grid toolkit since the 1970s. DR is now a CAISO  
19 market integrated product that allows grid operators to manage system  
20 demand via customers shifting their electricity consumption patterns,  
21 typically in response to incentives or other pricing signals. This poses little  
22 change to grid architecture as a load drop product.

23 The second agreement is the Distributed Energy Resource Provider  
24 Agreement (DERA) which was approved by the Federal Energy Regulatory  
25 Commission (FERC) in 2016, largely aligns with FERC Order 2222  
26 (proposed in 2020), and allows aggregated DERs to provide services to the  
27 CAISO market in the form of either export or load reduction. This  
28 agreement poses challenges for grid architecture when the resources  
29 export, necessitating tools for visibility and control with two-way power flow.  
30 While PG&E does not currently have any customers using the DERA

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<sup>13</sup> CEC, 2020 Load Management Rulemaking Docket #19-OIR-01, at:  
<<https://www.energy.ca.gov/proceedings/energy-commission-proceedings/2020-load-management-rulemaking>> (as of June 7, 2021).

1 agreement in its service territory; if the model is used it could pose  
2 challenges to current grid architecture.

### 3 **8. Public Policy-Driven Growth in Behind-the-Meter Solar and Storage**

4 California adopted NEM in 1995 to facilitate customer self-generation of  
5 renewable energy. The state subsequently approved a series of changes to  
6 the program that increased and ultimately eliminated the cap on  
7 installations. Today, California utility customers have installed 9.1 gigawatts  
8 (GW) of behind-the-meter renewable capacity—in most cases rooftop  
9 solar—with 4.7 GW of that capacity located in PG&E's territory.<sup>14</sup>

10 Under the California NEM program, customers that install  
11 behind-the-meter renewable generation can offset their energy consumption  
12 at or near the full retail rate and are credited for any energy that their system  
13 exports to the grid. The credit for any exports up to the customer's annual  
14 usage is at the full retail rate for pre-2017 installations and near the full retail  
15 rate for installations 2017 and later. Any energy generated above a  
16 customer's annual usage is paid at the wholesale energy rate. As part of  
17 the "NEM 2.0" proceeding, all new solar customers who installed solar in  
18 2017 or later were required to adopt time-of-use (TOU) rates.<sup>15</sup>

19 In 2020, the CPUC opened its "NEM 3.0" process to reconsider the  
20 NEM program and redesign the mechanism such that it appropriately  
21 promotes behind-the-meter generation, while simultaneously shielding  
22 non-participating customers from burdensome cost shifts. Notably, NEM 3.0  
23 is expected to explicitly consider the role of battery storage in the NEM tariff.  
24 While the outcome of the NEM 3.0 proceeding is not yet clear, the design of  
25 the new NEM program will impact the adoption of behind-the-meter solar  
26 and battery storage in PG&E's service territory. The CPUC committed to  
27 issuing a decision in the NEM 3.0 proceeding by end of 2021.

### 28 **9. New Momentum for Clean Fuels for Resiliency**

29 A more nascent trend in PG&E's service territory is the potential for  
30 leveraging clean fuels to maintain resiliency during PSPS events and other  
31 climatic events. Leveraging hydrogen or renewable natural gas for single or

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14 DG Products and Analysis, Distributed Generation Regular Reporting.

15 D.16-01-044, Section 2.14.1.3, starting at p. 91.

1 multi-customer electric resiliency applications (e.g., fuel cells) could provide  
2 an avenue for customers to ensure they have reliable supply leveraging their  
3 existing PG&E gas interconnections. It is not yet clear to what extent this  
4 trend will manifest in the coming decade, but PG&E will monitor  
5 developments in this area.

## 6 **10. Population Migration in PG&E's Service Territory**

7 Given the rapid evolution in California's climate, economic uncertainty  
8 driven by the macroeconomy (e.g., COVID-19), and the rising cost of living  
9 in the state, PG&E could observe operationally-relevant migration both in  
10 and out of its service territory and within the service territory itself. For  
11 example, rising temperatures in the Central Valley may shift agricultural  
12 loads within the state over the coming decades. Unsustainable  
13 homeowner's insurance rates in High Fire Threat District areas may cause  
14 the rural population to migrate to lower risk locations, such as urban and  
15 suburban areas or out of state. Looking further into the future, sea-level rise  
16 could shift California's coastal population toward urban centers.

17 It is not yet clear to what extent these trends, and other anticipated  
18 long-term population migration, will manifest at a level which warrants  
19 significant changes in PG&E's grid planning and operations in the next  
20 decade. PG&E's Climate Resiliency organization works to assess the  
21 potential impacts of such climate-related population trends on electric  
22 planning and operations and will continue to monitor these trends in the  
23 coming years.

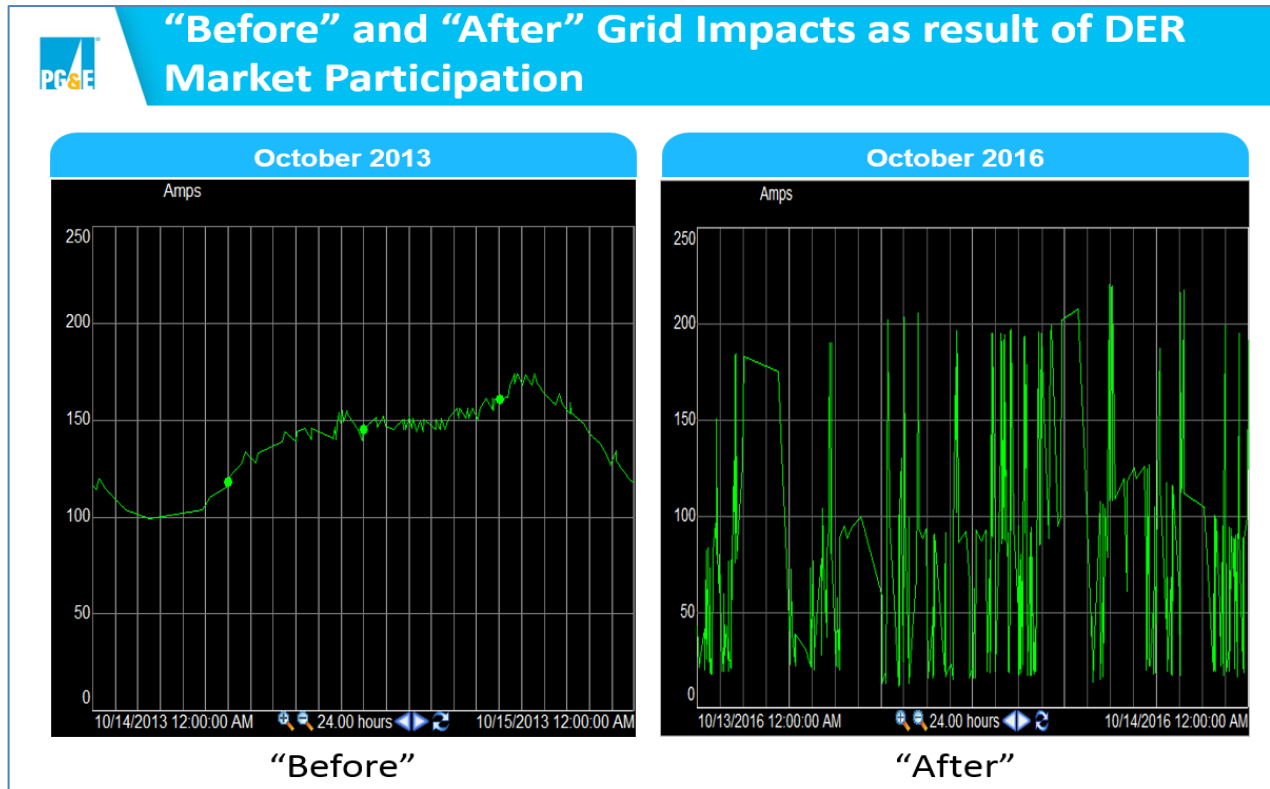
## 24 **11. DER-Specific Integration Challenges**

25 PG&E has steadily improved electric grid safety and reliability over the  
26 past decade, even as DER technologies have been adopted in increasing  
27 numbers. However, the interaction of these new customer-connected DERs  
28 with the existing grid has introduced new challenges including, but not  
29 limited to: (a) new grid usage patterns creating unpredictable bi-directional  
30 power flows that can interfere with the proper operation of existing voltage  
31 control and protection devices; (b) "masked" loads; (c) communication and  
32 cybersecurity issues, and (d) reverse flows from the distribution grid to the  
33 transmission grid in certain locations.

1           **a. New Grid Usage Patterns Create Unpredictable Power Flows**

2           In the past, electric distribution operators relied on a daily or  
3           seasonal cycle of energy usage as a basis for grid control decisions;  
4           today, however, new electric grid usage patterns have created  
5           unpredictable bi-directional power flow, adding complexity and  
6           increasing risk in managing the safe and reliable operation of the  
7           distribution system. As part of PG&E’s Electric Program Investment  
8           Charge (EPIC) 2.02 Demonstration Project, PG&E monitored “real-time”  
9           power flows on a specific distribution feeder where a 4 MW advanced  
10          energy storage unit participating in the CAISO’s frequency regulation  
11          market was interconnected onto PG&E’s distribution grid. The following  
12          figure, derived from this project, illustrates the dramatic difference in the  
13          feeder’s loading profile; the graph on the left depicts a 24-hour  
14          distribution feeder loading profile “before” interconnection of the  
15          advanced energy storage unit, while the graph on the right depicts a  
16          more volatile and unpredictable loading profile (for the same distribution  
17          feeder) due to the interconnection of this advanced energy storage unit  
18          that is participating in the CAISO frequency regulation market.

FIGURE A-1  
 EXAMPLE OF “BEFORE” AND “AFTER GRID IMPACTS,  
 DER WHOLESALE MARKET PARTICIPATION



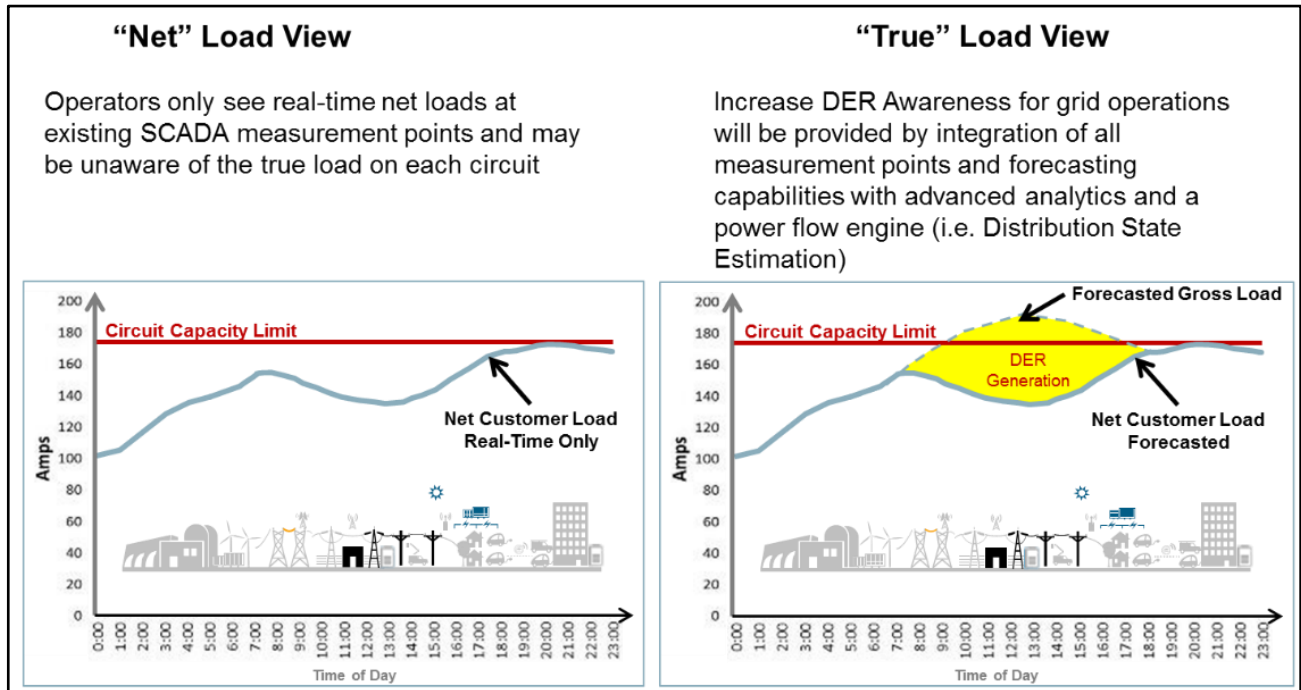
1                    Aside from energy storage interconnections, EV charging could also  
 2                    contribute to unpredictable power flows due to various times of the day  
 3                    where EV customers may elect to charge their vehicles.

4                    **b. “Masked” Loads**

5                    “Masked” load refers to situations where only the net of consumption  
 6                    and generation load is visible to distribution operators and/or where an  
 7                    asset is not separately metered (e.g., a battery at home). Currently,  
 8                    utility distribution operators only see “real-time” net loads at existing  
 9                    Supervisory Control and Data Acquisition (SCADA) measuring points  
 10                    and may be unaware of the true load on each distribution feeder since  
 11                    some of that load is being served by behind-the-meter generation, such  
 12                    as a roof-top solar system. At high levels of DER penetration,  
 13                    distribution operator awareness of the true load is necessary to ensure  
 14                    safe and efficient system reconfiguration during outage restoration,  
 15                    electric service interconnections, and grid maintenance. The following

1 figure illustrates the difference between distribution operators' current  
2 "net" load view and a potential future "true" load view.

**FIGURE A-2**  
**"NET" VS "TRUE" LOAD**



3 **E. 10-Year Vision: Grid Infrastructure**

4 PG&E anticipates the most significant grid modernization changes in the  
5 next decade will involve the design and implementation of more resilient and  
6 flexible grid infrastructure to meet the evolving needs of California's climate and  
7 political energy landscape.

8 **1. Grid Hardening That Enables DERs**

9 PG&E has one of the most diverse service territories in the utility  
10 industry, covering 70,000 square miles in Northern California and including  
11 most climate zones found in the United States. PG&E's grid traverses  
12 agricultural growing regions, coastal areas, urban hubs, mountains, forests,  
13 and deserts.

14 Overhead construction of physical assets has long been preferred in  
15 PG&E's service territory because underground assets are more difficult to  
16 access, and thus more costly to construct and maintain. However, as

1 California's climate has rapidly changed, overhead assets are increasingly  
2 at risk of both succumbing to and creating hazardous conditions. Although  
3 equally applicable to customers served traditionally and customers served  
4 by DERs integrated on the grid, wildfire threat has substantially increased in  
5 California and prompted PG&E to harden vulnerable infrastructure to avoid  
6 fire ignition and asset damage. Detailed descriptions of system hardening  
7 activities associated with wildfire threat can be found in Chapter 4.3 of this  
8 exhibit.

9 Climatological pressures aside from wildfires also threaten the California  
10 landscape. Due to factors such as sea level rise, coastal erosion,  
11 intensifying storm surge, and increasingly frequent and extreme high heat  
12 events, PG&E is identifying high-risk physical assets in its service territory  
13 via a comprehensive Climate Vulnerability Assessment (CVA).<sup>16</sup> PG&E's  
14 CVA will provide the foundation for a comprehensive, risk-informed set of  
15 adaptation measures that will likely include weatherization efforts that  
16 benefit all customers, including those supplied by DERs that are integrated  
17 onto the grid. PG&E will explore weatherization protections for these assets,  
18 such as constructing levees around substations to protect against  
19 increasingly severe weather. There may be additional emerging forms of  
20 risk that PG&E's assets, operations, and service may experience due to  
21 climate change. The likelihood and scope of cascading events (such as  
22 simultaneous events of flooding and extreme storms), or systemic and  
23 chronic risks (such as sea level rise) are difficult to quantify given lack of  
24 historical data or longer time horizons. In some cases, stand-alone climate  
25 adaptation projects may be necessary to manage systemic risk. Future  
26 climate conditions must be considered when building all new physical  
27 assets.

## 28 **2. Multi-Customer Microgrids**

29 Wildfire risk and wildfire-related PSPS events have prompted California  
30 to seek new methods to ensure resiliency. One of these methods is the use  
31 of multi-customer microgrids including those supplied by DERs, allowing

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<sup>16</sup> See D.19-10-054 and 20-08-046 for details, links are available, at:  
<<https://www.cpuc.ca.gov/climatechangeadaptation/>> (as of June 7, 2021).

1 customers to “island” from the centralized grid during hazardous weather  
2 conditions and outages. As described in Section D.3, PG&E is  
3 implementing programs aimed at accelerating microgrid adoption.  
4 Infrastructure like microgrid controllers, resilient communications and  
5 switching devices will need to be installed to successfully operate  
6 multi-customer microgrids. Additionally, PG&E’s broader system will require  
7 enhanced telemetry via its ADMS platform and SCADA upgrades to ensure  
8 microgrid operations do not impact overall reliability.

### 9 **3. Load Growth**

10 As described in Section D.4, environmental concerns have prompted  
11 California to enact decarbonization-focused mandates, including aggressive  
12 transportation and building electrification goals that rely, to a certain extent,  
13 on the enablement of DERs. PG&E supports cost-effective all-electric new  
14 construction and increased transportation electrification. However, to  
15 ensure safe and reliable service, the electric grid infrastructure needs  
16 enhancements to support electrification. Capacity upgrades of existing  
17 infrastructure will be needed to support growing demand, and new,  
18 greenfield T&D buildout may be required. DERs have a potential role to  
19 play in deferring some of these anticipated capacity projects.

### 20 **4. Non-Wires Alternatives**

21 The CPUC has required the Investor-Owned Utilities to implement the  
22 Distribution Investment Deferral Framework (DIDF), which promotes the  
23 development of non-wires alternatives to distribution capacity projects.<sup>17</sup>  
24 PG&E has created an annual process that provides opportunities for DERs  
25 to defer traditional wires investments. The DIDF program is described  
26 further in Chapter 17, which describes PG&E’s Capacity investments, and  
27 Chapter 21, which summarizes PG&E’s grid modernization investments.

28 PG&E has published information about PG&E’s distribution grid on its  
29 publicly available Distribution Resources Plan (DRP) Data Portal,<sup>18</sup>

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17 D.18-02-004, p. 52.

18 PG&E’s Distribution Resources Plan (DRP) Data Portal site, available at:  
<[https://www.pge.com/en\\_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page](https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page)> (as of June 7, 2021).

1 including opportunities for Non-Wires Alternatives and interconnection  
 2 hosting capacity for DERs (i.e., Integration Capacity Analysis (ICA)).

3 Additionally, programs like PG&E's Remote Grid Initiative represent a  
 4 nascent trend of considering standalone power systems fueled by DERs in  
 5 lieu of conventional electric distribution service. The expansion of programs  
 6 like Remote Grid over the coming decade will necessitate new capability  
 7 developments (e.g., deploying and servicing on-site DERs) and  
 8 infrastructure (e.g., advanced metering infrastructure).

9 Key priorities for grid infrastructure include:

10 Near-Term

- 11 • Provide opportunities for DERs as Non-Wire Alternatives to defer
- 12 traditional wires investments;
- 13 • Publication of ICA and DIDF results externally on the DRP Data Portal;
- 14 • Community Wildfire Safety Plan;
- 15 • Multi-customer microgrid infrastructure;
- 16 • Standalone power systems (e.g., Remote Grid Initiative); and
- 17 • Small to moderate-sized capacity projects to accommodate
- 18 electrification load growth.

19 Medium-Term

- 20 • Continuation of near-term programs, as necessary; and
- 21 • Significant capacity increases to accommodate load growth from EV
- 22 charging.

23 Long-Term

- 24 • Continuation of near- and medium-term programs, as necessary;
- 25 • Grid hardening for other climate forces (e.g., reinforcing or relocating
- 26 coastal substations and electric T&D assets due to sea level rise);
- 27 • High-Voltage Direct Current transmission; and
- 28 • Proactive investments in EV charging infrastructure or capacity to
- 29 enable future EV growth.

30 **F. 10-Year Vision: System Monitoring and Management**

31 PG&E anticipates that it will continue to make significant investments over  
 32 the next 10 years to create a new suite of sophisticated grid capabilities that will  
 33 enhance operators' ability to monitor and control the electric grid.

## 1. **Advanced Distribution Management System**

ADMS is an operational platform which allows distribution operators a single view of the distribution system's RT operations. ADMS replaces legacy control center software used to operate the electric distribution system with an integrated technology platform, enabling step-level improvements in PG&E's ability to monitor, manage, and control its network.

ADMS aggregates RT data from all telemetered field devices with the distribution management system and operational management system. The platform provides an enabling foundation upon which new capabilities can be developed and applied to a distribution system. Examples of these capabilities include: RT state estimation; more advanced fault location, isolation, and service restoration (FLISR); voltage management (e.g., Volt/Volt-Ampere Reactive (Volt/VAR) optimization); and dynamic switching (e.g., topology controls).

ADMS is the cornerstone of the second layer of PG&E's IGP pyramid, focused on system monitoring and management. PG&E's 2020 GRC Grid Modernization request included funding for the development and deployment of an ADMS. In its 2023 GRC, PG&E is requesting funding to finalize its ADMS deployment.

## 2. **Asset Sensors**

In order to aggregate telemetry data from throughout its electric T&D systems, PG&E will need to implement asset sensors throughout its grid on assets like substation equipment and transformers, as well as on T&D lines themselves. Data flow from these sensors is supported by PG&E's communication infrastructure, and the data is available to grid operators via the ADMS platform for DER and non-DER planning, monitoring, and communications.

## 3. **Distribution Planning Tools/Advanced Load Forecasting**

As described in Section C of Chapter 21, advanced distribution planning tools allow for more sophisticated analyses of system conditions. These tools enable scenario analysis, or the forecasting of system load under a variety of differing parameters, as well as analysis along multiple time series (e.g., intra-day, intra-year). Additionally, such tools can enable applications

1 related to the optimal siting of DERs. PG&E's core load forecasting tool,  
2 Load SEER, and PG&E's distribution power flow software, CYME, are  
3 anticipated to deliver this functionality in the coming years.

#### 4 **4. Distribution and Substation Automation**

5 The automation of technology and equipment to enable passive  
6 operation of the grid may improve the reliability and cost of electric grid  
7 operations in some cases. PG&E has focused to date on automation  
8 applications relating to substation SCADA equipment, as well as FLISR  
9 technology projects—first initiated in PG&E's Cornerstone investment  
10 program. As discussed above, the foundation for many of these automation  
11 applications will be unlocked once PG&E's ADMS system has been fully  
12 deployed.

13 Key priorities for system monitoring and management include:

##### 14 Near-Term

- 15 • Finalizing ADMS deployment;
- 16 • Installation of enabling communications infrastructure; and
- 17 • Advanced load forecasting tools.

##### 18 Medium-Term

- 19 • Continuation of near-term programs, as necessary; and
- 20 • Continued large-scale deployment of RT sensors for asset health and  
21 system conditions.

##### 22 Long-Term

- 23 • Continuation of near- and medium-term programs, as necessary; and
- 24 • Further automation of distribution system operations.

#### 25 **G. 10-Year Vision: DER Grid Services**

26 As DER growth may indicate, PG&E plans to build out a new suite of  
27 capabilities for monitoring and controlling DERs over the next 10 years because  
28 it anticipates significant activity will occur in the DER grid services space during  
29 that time.

##### 30 **1. Distributed Energy Resource Management System**

31 As DER growth requires and other system priorities allow, PG&E will  
32 deploy a DERMS in the coming decade, beginning with its forecast in the  
33 2023 GRC. DERMS is a foundational platform that will allow PG&E grid

1 operators to monitor and control DERs, unlocking the ability to leverage  
2 DERs as a resource for electric system planning and operations.

3 Ultimately, a DERMS system will enable PG&E to manage DERs and  
4 controllable loads (such as EV charging, air conditioners, and electric heat  
5 pumps) to support flexible grid operations. In some cases, the control of  
6 resources and loads through a DERMS system might enable the utility to  
7 supply growing loads stemming from vehicle and building electrification  
8 while moderating funding required for capacity investment.

## 9 **2. Frequency/Voltage Regulation**

10 Frequency regulation refers to the deployment of technology to mitigate  
11 short-term fluctuations in system operational frequency, driven by  
12 discrepancies between system supply and load. Similarly, voltage  
13 regulation technologies offer a similar mitigation functionality to ensure  
14 system voltage remains within established safety and reliability standards.  
15 Both frequency and voltage regulation are significant considerations given  
16 the rapid proliferation of DERs and other inverter-based devices within  
17 PG&E's service territory. With so many new inverter-based nodes, many of  
18 which can both import from and export to the grid, it has become much more  
19 difficult to ensure stable frequency and voltage conditions within the system.

20 In each case, a number of technologies can be applied to provide the  
21 ancillary services. Historically, sources of generation with the ability to be  
22 quickly dispatched have been targeted for frequency regulation; DR has also  
23 been used for a similar purpose. In recent years, front-of-the-meter storage  
24 applications have tested and evaluated additional value for project  
25 economics by monetizing storage facilities' abilities to provide frequency  
26 regulation. Conventional voltage regulation equipment like load tap  
27 changing transformers and capacitor banks has also been supplemented  
28 with more advanced Volt/VAR controls, including power electronics-based  
29 devices.

30 Given the expected growth in DERs like behind-the-meter solar paired  
31 with storage, PG&E's system will require further buildout of frequency and  
32 voltage regulation capabilities in the coming decade.

### 3. Smart Inverters

PG&E's EPIC Project 2.03A, *Test Smart Inverter Enhanced Capabilities – Photovoltaics (PV)*, tested and examined the application of smart inverters for local voltage control in regions of high DER penetration. Along with basic autonomous functionality to enable better grid integration of DERs, smart inverters can provide dispatch capabilities to support grid support services such as voltage regulation or capacity. These services increase communication between DERs and the grid, enabling smarter and more targeted use of resources. Since 2017, all new inverter-based DERs installed in California are required to have smart inverters and communication capabilities to integrate with utilities' DERMS.

### 4. Advanced Load Management

PG&E's DERMS platform will provide the base functionality to enable more sophisticated protocols for leveraging flexible and controllable load technologies (e.g., smart thermostats, electric heat pump water heaters) to provide grid services as customers and distribution planners need them. These technologies can help in providing conventional DR (i.e., peak load management during summer peak load periods), as well as more dynamic applications (e.g., local ancillary services).

### 5. Vehicle-to-Grid (V2G)

While the trend has not yet materialized on a significant scale, the potential of EVs to serve as dispatchable grid assets which can leverage the mobility and flexibility of EVs to provide services to the grid is being tested, evaluated, and piloted. Such applications would require new load projection capabilities to identify ideal locations for EV dispatch, as well as upgrades to allow for EVs to discharge significant load back into the electric grid. PG&E does not anticipate V2G applications to emerge on a large scale in the coming decade, but the Company will continue to test, evaluate, and monitor the technology's progress in the next few years.

Key priorities for DER grid services include:

#### Near-Term

- Enterprise DERMS installation; and

- Supporting the proliferation of smart inverters in PG&E's service territory.

Medium-Term

- Continuation of near-term programs, as necessary; and
- Deployment of more sophisticated load management schemes and integration into utility programs and DERMS.

Long-Term

- Continuation of near- and medium-term programs, as necessary; and
- Potential implementation of V2G functionality beyond localized pilots.

**H. 10-Year Vision: Distribution Markets**

PG&E anticipates minimal activity with respect to the design and implementation of advanced distribution markets within the next 10 years.

Implementation of advanced distribution markets would require several foundational elements, including a market platform and mechanisms for performing and settling transactions. As referenced in PG&E's 2020 GRC 10-Year Vision, PG&E anticipates that that these required elements would necessitate new infrastructure and capabilities that would need to be tested, evaluated, and piloted for effectiveness, feasibility, and net benefits before deployment. As a result, PG&E does not plan to prioritize significant investments in these areas in the coming decade. If momentum for such a marketplace materializes, PG&E will continue its commitment to work with technology providers and regulators to find cost-effective and viable solutions.

Key priorities for distribution markets include:

Near-Term

- *Not applicable.*

Medium-Term

- Ad hoc pilots to test and prove effectiveness of distribution market technologies.

Long-Term

- Continuation of medium-term programs, as necessary; and
- Potential design and implementation of distribution market platform.

1 **I. Conclusion**

2 PG&E’s electric delivery system is facing a confluence of changing  
3 technological, political, and climatic trends. In order to ensure safe, reliable,  
4 clean, and affordable service in light of this shifting landscape, PG&E foresees a  
5 number of new grid modernization programs that must be implemented in the  
6 coming years – from the near-term view of this GRC cycle to items that may fall  
7 outside of the next decade but will one day impact the grid. A near-term focus  
8 on bolstering grid infrastructure and system monitoring and management  
9 functionality will ensure that the business is prepared with the physical and  
10 digital toolkit needed to manage changing grid conditions. With the deployment  
11 of a DERMS platform, PG&E will continue its efforts to enable DERs to  
12 participate in the planning and operation of the electric T&D systems. Finally,  
13 while an advanced distribution market is not forecast to emerge in the next ten  
14 years, PG&E will monitor the necessary indicators to ensure the business is  
15 prepared to meet that challenge, if or when it materializes.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 21**  
**ATTACHMENT A1**  
**GRID MODERNIZATION PLAN – UPGRADES INITIATED OR**  
**COMPLETED TO DATE**

1                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                                   **CHAPTER 21**  
3                                   **ATTACHMENT A1**  
4                   **GRID MODERNIZATION PLAN – UPGRADES INITIATED OR**  
5                   **COMPLETED TO DATE**

6   **Distribution Planning Tools**

7   CYME

8       This software for distribution power flow and fault study modeling was  
9   implemented in 2011 to replace the in-house developed C-EDSA. The CYME  
10 gateway pulls information from Pacific Gas and Electric Company's (PG&E or the  
11 Company) Geographic Information System (GIS) system to create circuit models  
12 from circuit breaker to service transformer in an Oracle database.

13 LoadSEER

14       This software was implemented in 2012 and is used for PG&E's geospatial load  
15 forecasting which brings our system level forecast down to the feeder level with a  
16 top-down bottom-up allocation. This tool helps PG&E estimate and forecast load  
17 shapes where Supervisory Control and Data Acquisition (SCADA) data is not  
18 available.

19 Integration Capacity Analysis (ICA)

20       This cloud-based software enables automated computation of a system-wide  
21 ICA, that is the load and generation hosting capacity for different nodes of PG&E  
22 distribution grid. The platform enables PG&E to execute manage-by-exception  
23 workflows to ensure completeness of model data and resolve CYME power flow  
24 issues in a methodical, collaborative, and consistently repeatable process. The  
25 results are published on a monthly cadence on PG&E's Distributed Resource  
26 Planning Data Portal, to comply with Distribution Resource Plan (DRP) (Rulemaking  
27 (R.) 14-08-013) proceeding. The public data will be utilized as a part of Rule 21  
28 (R.17-07-007) screenings for new interconnection applications.

29 Distribution Investment Deferral Framework (DIDF)

30       PG&E is responsible for providing opportunities to DERs to defer distribution  
31 services via the DRP (R.14-08-013), as well as Incentive Pilots via the Distributed  
32 Energy Resources Distribution Deferral Account (R.14-10-003). Through the DRP,  
33 PG&E has developed the DIDF to procure distribution deferral services to replace or

1 defer traditional wire-based projects in the Company's project planning pipeline.  
2 PG&E also publishes annually its Grid Needs Assessment and Distribution Deferral  
3 Opportunity Report. To date, PG&E has solicited for over 60 megawatts of DERs at  
4 14 different candidate deferral opportunity locations.

#### 5 DRP Data Access Portal

6 In 2020, PG&E announced a refresh of its data access portal for its DRP. This  
7 portal provides access to maps and other resources for the optimal siting of DERs  
8 for third-party contractors and developers. The map provides access to PG&E's ICA  
9 and DIDF results.

#### 10 Distributed Generation Interconnection Process

11 Consistent investments and interconnection process improvements have  
12 reduced interconnection times. Automated application processing (the Net Energy  
13 Metering (NEM) Web Portal), launched in early 2015, expedites evaluating Rule 21  
14 applications within PG&E's service territory. These improvements lead to industry  
15 leading interconnection times, and in 2014, Standard NEM projects experienced a  
16 median interconnection timeframe averaging only three business days after  
17 completing their interconnection application.

### 18 **Distribution Operations Tools**

#### 19 Advanced Distribution Management System (ADMS)

20 PG&E began implementation of its ADMS system with the 2020 General Rate  
21 Case (GRC) cycle. ADMS is a platform that aggregates various components of  
22 operations (e.g., Distribution Supervisory Control and Data Acquisition (D-SCADA),  
23 Outage Management System (OMS)) into a single operational platform. Release 1  
24 (R1) of ADMS began in May 2019 and is expected to go-live in July 2022 for  
25 five divisions. R1 replaced SCADA and rules-based fault location isolation and  
26 service restoration (FLISR), deployed a new network model, and automates key  
27 processes for fire mitigation. Further ADMS implementation will continue in the  
28 coming years.

#### 29 OMS

30 Along with D-SCADA, PG&E's OMS is the central platform used by  
31 Distribution Operators to manage planned outages, and quickly identify, locate, and  
32 isolate unplanned outages. This platform also interfaces crew scheduling and

1 resourcing to restore outages as quickly as possible, as well as with customer  
2 notification systems.

### 3 Integrated SCADA and Distribution Management System (DMS)

4 The initial DMS software deployed in 2015 to support the control center  
5 consolidation provided basic capabilities, including an electronic mapping system to  
6 eliminate the use of paper wall maps and push pins to track electric distribution  
7 system operations. SCADA and DMS are not currently integrated, requiring  
8 operators to manually transfer data between systems and view different computer  
9 screens to see activity throughout the system. In this GRC cycle, PG&E proposes to  
10 integrate D-SCADA with DMS and OMS to form ADMS. This integration will result in  
11 seamless and transparent user interfaces for improving operator safety, reliability,  
12 and efficiency. The new ADMS, along with upgrades to communication  
13 infrastructure, will enable PG&E to communicate with and control the large number  
14 of forecasted DERs to maintain/enhance stable grid operation in the future.

### 15 Distribution Control Center Consolidation

16 PG&E consolidated its 13 Distribution Control Centers down to three  
17 state-of-the-art facilities over a multi-year project that has transformed how it  
18 monitors and operates its electric grid. Benefits include enhanced reliability, quicker  
19 response to outages and emergencies such as natural disasters, and increased  
20 capabilities to continue adding clean, renewable power sources such as solar and  
21 wind. The new control centers have been equipped with systems that support  
22 today's Smart Grid technology but will also support future upgrades as well. New  
23 technology incorporates advanced electronic mapping of PG&E's electric distribution  
24 grid and SmartMeter™ data to help operators pinpoint the exact location of an  
25 outage, which will expedite restoration efforts.

## 26 **Grid Connectivity Model**

### 27 GIS

28 The Electric Distribution GIS project enhanced and converted PG&E's  
29 distribution system asset data into an integrated GIS/ SAP AG Software system that  
30 provides analytical and visualization tools to enhance Electric Distribution asset  
31 management and operations. The project formed the foundation of the digital  
32 network model utilized within DMS, OMS, and ADMS, and also provided the  
33 technology tools to update and validate asset data and enable mobile applications

1 for field personnel to collect inspections, testing, and maintenance data at the  
2 worksite.

### 3 **Sensors and Controllers**

#### 4 D-SCADA

5 PG&E's D-SCADA system gathers, processes, and displays electric system  
6 status, enables remote control of equipment, and provides operational data to  
7 operators at control centers and other PG&E employees. The D-SCADA system  
8 consists of a software application with visualization tools in the distribution control  
9 centers, and field devices which send and receive data and control signals. PG&E  
10 began installing SCADA-equipped sensors on its distribution and transmission lines  
11 in 1986 and SCADA is now enabled within nearly 100 percent of substations and  
12 over 11,500 field devices.

#### 13 SmartMeters

14 PG&E has installed over 5 million electric SmartMeters throughout its service  
15 area, beginning in 2011. SmartMeters transformed a system that once relied on  
16 meter readers that collect data once a month to a system that digitally collects  
17 energy usage information every hour. SmartMeters have enabled 5.5 million  
18 customers to have access to their hourly energy usage information made available  
19 via PG&E's My Energy website. Data from SmartMeters and is also now  
20 integrated into Distribution Operations systems to identify outages and provide  
21 system telemetry.

#### 22 Smart Inverters

23 In California, the Electric Rule 21 Generating Facility Interconnections Tariff  
24 governs the requirements for interconnecting generation facilities on the  
25 Distribution System. Rule 21 Section Hh has required customers to install over  
26 200,000 certified smart inverters for Distribution interconnections in PG&E's territory  
27 starting in late 2017, with additional functionality added in subsequent years. Smart  
28 inverter functionality includes autonomous protective functions, power quality  
29 support, ride-through capabilities, and most recently, monitoring and control via  
30 communications capabilities. Smart inverters help mitigate the adverse effects of  
31 ever-increasing levels of distributed generation on PG&E's system, as well as  
32 provide a path for remote configuration of these assets as the grid and DER  
33 programs continue to evolve.

## Fault Location Isolation and System Restoration (FLISR)

FLISR systems reduce the impact of outages by quickly opening and closing automated switches to reduce what may have been a one- to two-hour outage to less than five minutes. Over 975 circuits on the distribution system are supported by FLISR, which was first funded in the Cornerstone Decision (Decision (D.) 10-06-048).

## Line Sensors and Fault Indicators

PG&E has installed overhead fault indicators and line sensors to improve reliability by more quickly identifying fault locations through visible targets or through remote detection in the case of line sensors. By more quickly identifying locations of circuit trouble, PG&E can more rapidly isolate failed equipment and restore service after unplanned outages. PG&E has installed over 180 line sensors and over 36,000 fault indicators in its service territory to date.

## Relay Replacement

PG&E is actively replacing older mechanical relays with new solid-state relays that have integrated protection, automation, and control functionality. This integrated replacement approach allows for more cost-effective installation and testing, and standardizes design, which leads to better operability compared to separately installed systems. PG&E's System Protection Department manages a relay replacement list, and prioritizes replacements based on age and other technical evaluation factors including but not limited to criticality of the station, number of customers that could be affected, and type of customers. PG&E proposes to replace protective relays on an average of 30 substation transformers annually through 2026.

## **Communications Infrastructure**

PG&E's communication backhaul network supports a wide variety of sensors, controls, end devices, and employee electronics. The network is comprised of: (1) a Wide Area Network (WAN) that ties PG&E's data centers to the rest of PG&E's locations, users, business partners, and customers; (2) a Transport Network—comprised of fiber optic cables, microwave transmitters, leased lines from third-party carriers that provides connectivity between sites across the WAN; and (3) a private Field Area Network (FAN) carries information to and from devices in the field and connect them to WAN or the SCADA system. FAN technology provides the

1 performance to handle the real time data transmission requirements of emergent  
2 grid control and automation technologies.

### 3 **Battery Storage Projects**

4 PG&E has utilized Battery Energy Storage Systems since 2012. The Vaca-  
5 Dixon 2 megawatt (MW)/14 MW Alameda Naval Air Station (NAS) Battery project at  
6 the Vaca-Dixon Substation became operational in August 2012 and commenced  
7 California Independent System Operator (CAISO) Market operations in August 2014.  
8 It is 100 percent dedicated to CAISO wholesale market participation. The Yerba  
9 Buena 4 MW/28 megawatt-hour (MWh) NAS Battery project at a Customer  
10 Research and Development Facility in San Jose became operational in May 2013. It  
11 is used for daily peak shaving and has the ability for half energy reserved for  
12 islanding/backup for the adjacent customer facility. The Browns Valley  
13 500 kilowatt/2 MWh li-ion Battery project at Browns Valley Substation became  
14 operational in January 2017 and is used for seasonal peak shaving and deferral of  
15 distribution bank replacement. The Elkhorn 182.5 MW/4 hr storage system at Moss  
16 Landing Substation and the Llagas 20 MW/80 MWh projects are approved and  
17 under construction.

### 18 **Microgrid Deployments**

19 PG&E has collaborated with the Redwood Coast Energy Authority, Schatz  
20 Energy Research Center at Humboldt State University, Humboldt County, and  
21 Schweitzer Engineering Laboratories, among others in development of the Redwood  
22 Coast Airport Microgrid. This front-of-the-meter, multi-customer microgrid featuring  
23 solar power generation paired with battery energy storage is under construction and  
24 on schedule for full operation in Q4 2021. The microgrid will provide renewable  
25 energy for 18 customer meters, including the Arcata-Eureka Airport and a U.S.  
26 Coast Guard Air Station, and will be capable of disconnecting from the broader grid  
27 (island mode) and operating as an independent, PG&E-operated grid segment  
28 during a planned or unplanned power outage.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 21**  
**ATTACHMENT A2**  
**DER-RELATED RESEARCH, DEVELOPMENT AND**  
**DEMONSTRATION (RD&D) PROJECTS**

1                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                                   **CHAPTER 21**  
3                                   **ATTACHMENT A2**  
4                   **DER-RELATED RESEARCH, DEVELOPMENT AND**  
5                   **DEMONSTRATION (RD&D) PROJECTS**

6           The following describes Pacific Gas and Electric Company’s (PG&E)  
7 RD&D-related project achievements and their influence on the five key areas of the  
8 proposed Grid Modernization Program portfolio: (1) Distribution Operations  
9 Platforms including the Advanced Distribution Management System (ADMS) and  
10 Distributed Energy Resource Management System (DERMS); (2) Distribution  
11 Engineering Planning Tools; (3) Battery System Deployment; (4) Microgrid  
12 Deployment; and (5) Communication Infrastructure.

13  
14           **RD&D Projects Supporting the ADMS and DERMS Platforms**

15           **Electric Program Investment Charge (EPIC) 2.02 Demonstration DERMS:**  
16 Distribution Management Systems (DER) may provide benefits to the grid if there is  
17 sufficient visibility and control of the resources. EPIC Project 2.02 demonstrated a  
18 scaled down ADMS and a DERMS platform to monitor and coordinate the control of  
19 various types of distributed energy resources, including Distributed Generation and  
20 energy storage to manage system constraints and provide distribution grid services.  
21 This demonstration’s learnings are incorporated into PG&E’s proposed  
22 ADMS/DERMS solution in the Integrated Grid Platform, addressing how capabilities  
23 fit together and what capabilities PG&E will need to manage an increasingly complex  
24 distribution grid while enabling new value streams from DERs. This includes  
25 operational capabilities and application implementation (ADMS and DERMS),  
26 foundational model/system improvements to enable these applications (Geographic  
27 Information System (GIS) and other data improvement), monitoring and  
28 communications to provide necessary DER visibility, and standardizing and securing  
29 integration with DERs.

30           **EPIC 2.03A Test Smart Inverter Enhanced Capabilities:** This project  
31 assessed how to leverage customer-sited Smart Inverters for grid benefits by  
32 remotely controlling them (via vendor portals or third-party aggregator platforms) for  
33 voltage/frequency regulation and mitigation of reverse power flow adverse effects.

1 This project ultimately informs distribution planning, interconnection enhancements,  
2 ADMS requirements, customer program(s) related to smart inverters, as well as  
3 policies and contractual agreements for customers to allow PG&E to use/control  
4 their smart inverters in the service of power quality.

5 **EPIC 2.14 Phase ID:** To improve distribution network models, this project  
6 demonstrated a variety of pre-commercial analytics and hardware options to  
7 automatically map three-phase electrical power information, including meter to  
8 transformer mapping, which will be scaled up through improved GIS data and  
9 leveraged by PG&E's proposed ADMS solution.

10 **EPIC 2.07 Meter Loading Data:** To advance switching-related decision making  
11 for grid operators, this project created an advanced algorithm using SmartMeter™  
12 data to more accurately estimate circuit-level meter load and demonstrate how to  
13 aggregate real-time loading data up through the distribution model. This  
14 functionality demonstrated in this project will inform ADMS design requirements.

15 **EPIC 3.03 DERMS and ADMS Advanced Functionality:** To develop a low-  
16 cost solution for DER telemetry & control, this project is developing a DERMS  
17 head-end system and associated interfaces and demonstrating this system on:  
18 (1) an operational remote grid and (2) the Blue Lake Rancheria microgrid in  
19 Humboldt County. This project will inform operating strategies and produce  
20 capabilities to significantly increase the flexibility of the grid and provide fundamental  
21 capabilities to reduce overall wildfire risk exposure and increase resilience for  
22 customers. The project will also reduce the cost of telemetry associated with large  
23 scale DERs interconnected to PG&E's grid.

## 24 25 **RD&D Projects Supporting Distribution Engineering Planning Tools**

26 **EPIC 2.22 Demand Reduction for Targeted Analytics:** To automate the  
27 approach for identifying least-cost, best-fit DER portfolio recommendations, this  
28 project used grid, SmartMeter, customer demographic, DER load impact, and other  
29 data sources to proactively identify non-wires alternative opportunities, recommend  
30 an optimized portfolio of DER technologies, and provide specific customer and  
31 technology recommendations by location based on grid need. The project  
32 investigated whether PG&E can achieve a sufficient amount of demand reduction,  
33 give visibility into the customer-side resources, and improve the reliability of  
34 customer-side resources at the local level to delay the need for local capacity

1 expansion expenditures. This project was completed in 2018 and is being scaled up  
2 to support PG&E's advancing distribution planning processes through optimized  
3 location-specific targeting to leverage cost-effective, non-wires alternatives based on  
4 grid need.

5 **EPIC Project 2.23 Integrate Demand-Side Approaches into Utility Planning:**

6 This project successfully developed and demonstrated the integration of a broader  
7 range of customer-side technologies and DER approaches into the utility planning  
8 process. The project served as a necessary and enabling precursor to the fulfillment  
9 of Assembly Bill 327/Section 769, which requires transparent, consistent, and more  
10 accurate methods to cost-effectively integrate DERs into the distribution planning  
11 process. This project delivered new load shape profiles, and an enhanced load  
12 forecasting tool and overall analytical process that allows PG&E to more accurately  
13 and consistently integrate DER impact to the distribution system load profile. With  
14 these enhancements, PG&E can evaluate if DER growth could defer or even in  
15 some instances eliminate the need for future network upgrades. Leveraging  
16 SmartMeter data, PG&E created more accurate and granular load shapes that  
17 allowed distribution planners to more precisely capture DER impact on the load  
18 growth forecast.<sup>1</sup>

19 Ultimately, EPIC Project 2.23 helps ensure that DER forecasts are incorporated  
20 in PG&E's planning process and EPIC Project 2.22 will help identify areas where  
21 additional DERs could provide grid value.

22  
23 **RD&D Projects Supporting Battery System Deployment**

24 **EPIC 1.01 Energy Storage End Uses and EPIC 1.02 Demonstrate Use of**  
25 **Distributed Energy Storage for Transmission and Distribution Cost Reduction:**

26 EPIC Project 1.01 utilized PG&E's Vaca Dixon and Yerba Buena Sodium Sulfur  
27 Battery Energy Storage Systems to automatically participate in California  
28 Independent System Operator's (CAISO) Non-Generator Resource market to gain  
29 real-world experience and performance data for operating batteries as market  
30 resources. The project developed and deployed an automated communications and  
31 control solution platform to enable these and future resources to respond

---

1 <sup>1</sup> EPIC 2.23 Final Report: [https://www.pge.com/pge\\_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.23.pdf](https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.23.pdf).

1 automatically to CAISO market awards.<sup>2</sup> EPIC Project 1.02 was designed as a  
2 complement to PG&E's EPIC Project 1.01; EPIC Project 1.01 focused on the  
3 potential energy market values for energy storage, while EPIC Project 1.02 focused  
4 on the non-market, distribution functionality of energy storage assets. Specifically,  
5 EPIC Project 1.02 deployed a 500 kilowatt/2 megawatt-hour energy storage system  
6 at the Browns Valley substation and integrated the energy storage system control  
7 into PG&E's Supervisory Control and Data Acquisition system to deliver autonomous  
8 distribution peak shaving functionality. The project learnings have informed PG&E's  
9 and other utilities' procurement of future energy storage resources, both utility-  
10 owned and utility-contracted, through compliance with the Investor-Owned Utility  
11 energy procurement targets as set forth in Decision 10-03-040 and beyond.<sup>3</sup>

### 12 **EPIC 2.19 Enable Distributed Demand-Side Strategies and Technologies:**

13 This project demonstrated the potential to use customer-sited energy storage  
14 technologies to reduce peak loading and absorb DER generation. For  
15 behind-the-meter energy storage assets to be reliably used for distribution or grid  
16 services, PG&E will need to have additional hardware and software systems  
17 (e.g., two-way communication systems, operational protocols and priorities, a  
18 DERMS platform, sensors and controls, etc.) to provide accurate visibility into asset  
19 performance and availability, and assurances that the behind-the-meter energy  
20 storage assets will consistently and reliably respond to dispatch signals. These  
21 gaps identified will be incorporated into PG&E's proposed ADMS platform.<sup>4</sup>

### 22 **RD&D Projects Supporting Microgrid Deployment**

23 **EPIC 3.11 – Location Targeted DERs:** This project is configuring the  
24 Arcata-Eureka airport's local microgrid controller to integrate with PG&E's  
25 distribution network and enable Distribution Control Center visibility and control of  
26

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2 <sup>2</sup> EPIC 1.01 Final Report: [https://www.pge.com/pge\\_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.01.pdf](https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.01.pdf).

3 <sup>3</sup> EPIC 1.02 Final Report: [https://www.pge.com/pge\\_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.02.pdf](https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-1.02.pdf).

4 <sup>4</sup> EPIC 2.19 Final Report: [https://www.pge.com/pge\\_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.19.pdf](https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-program-investment-charge/PGE-EPIC-Project-2.19.pdf).

1 the microgrid. The project is developing scalable and replicable approaches to  
2 planning, designing, deploying, and operating multi-customer microgrids. At an  
3 additional site with existing high penetration of advanced DERs, this project will also  
4 develop and demonstrate capabilities to enable intelligent coordination between  
5 customer DERs and the main utility grid under normal operation and to provide real-  
6 time resiliency support when operated as a microgrid or Public Safety Power Shutoff  
7 island including utility temporary generation. The results of this project will inform  
8 operating strategies and produce capabilities to significantly increase the flexibility of  
9 the grid and provide fundamental capabilities to advance system resiliency.

10  
11 **RD&D Projects Supporting Communications Infrastructure**

12 **EPIC 2.26 Customer and Distribution Automation Open Architecture**

13 **Devices:** This project evaluated how to allow customers and vendors to connect  
14 and communicate with their DER devices and applications over the Advanced  
15 Metering Infrastructure (AMI) network by testing open system architecture with  
16 defined methodology, protocols, and standards using the Internet Protocol version 6  
17 (IPv6) AMI network. The project provided physical and application interfaces to  
18 permit customer and third-party devices to connect to PG&E's AMI network(s) and  
19 conducted testing to certify customer and third-party open architecture devices and  
20 applications are AMI compatible, highly secured, interoperable, and meet all PG&E  
21 requirements.

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 21**  
**ATTACHMENT A3**  
**COMMUNITY MICROGRID ENABLEMENT PROGRAM**  
**EVALUATION**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 21  
COMMUNITY MICROGRID ENABLEMENT PROGRAM EVALUATION

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1                                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                                   **CHAPTER 21**  
3                                   **COMMUNITY MICROGRID ENABLEMENT PROGRAM EVALUATION**

4   **A. Background**

5           The California Public Utilities Commission (CPUC or Commission) approved  
6           the Community Microgrid Enablement Program (CMEP) framework in Decision  
7           (D.) 20-06-017. In that Decision, the Commission directed Pacific Gas and  
8           Electric Company (PG&E) to file an Implementation Plan advice letter. That  
9           Implementation Plan advice letter<sup>1</sup> was approved by the CPUC, with  
10          modifications, on March 18, 2021 in Resolution (Res.) E-5127.

11          D.20-06-017 directed that PG&E include a program evaluation of CMEP in  
12          its 2023 General Rate Case (GRC). As stated in that Decision, “The GRC  
13          evaluation shall enable the Commission to evaluate the efficacy of the program  
14          and determine whether the program should continue beyond 2022.”<sup>2</sup> As directed  
15          in that Decision and in Res.E-5127, PG&E provides below an evaluation of  
16          CMEP’s project size cap, eligibility criteria, application process, cost offset  
17          reservation trigger, and feedback on its outreach plan to disadvantaged and  
18          vulnerable communities.

19          Since the program was only fully approved in March 2021, PG&E has had  
20          limited time and experience with the program. However, PG&E is still able to  
21          provide an initial program evaluation based on its work thus far with communities  
22          under the program. PG&E will also share the lessons learned through the  
23          CMEP thus far as part of the Microgrid Incentive Program (MIP)<sup>3</sup> development  
24          process in order to help inform the development of that program. Indeed, the

---

1   PG&E Advice Letter 5918-E.

2   D.20-06-017 p. 85.

3   As part the Microgrid and Resiliency Strategies Track 2 Decision (D.21-01-018), the Commission adopted the MIP as an expansion of the original CMEP concept, applicable to all three large IOUs in California. The IOUs are preparing to conduct stakeholder outreach regarding the MIP design and are required under the Track 2 Decision to file a detailed implementation letter within 120 days of the stakeholder outreach advice letter receiving approval.

1 CPUC in D.21-01-018 authorized PG&E to propose changes to the CMEP that  
2 may be necessary to integrate the program more fully with the MIP.<sup>4</sup>

### 3 **B. Project Size Cap**

4 The Community Microgrid Enablement Tariff (CMET), which PG&E  
5 submitted to the Commission as part of its CMEP implementation advice letter,  
6 allows Project Resources sized in aggregate up to 20 megawatt (MW). PG&E  
7 chose this project cap size in order to correspond generally with requirements to  
8 interconnect at the distribution level of PG&E's system. Facilities larger than 20  
9 MW would typically need to be connected to a substation bus or transmission  
10 line, which is a more complex and expensive undertaking outside the target  
11 scope and funding for the CMEP.

12 Several parties to the Microgrids and Resiliency proceeding<sup>5</sup> have  
13 requested that PG&E clarify whether this project size cap refers to nameplate  
14 capacity or export capacity, and some have requested that it refer to export  
15 capacity or that the cap be raised. Some customers have made a similar  
16 request. PG&E clarifies that nameplate capacity, as described in the CMEP  
17 implementation advice letter,<sup>6</sup> was the intent. However, PG&E will further  
18 consider this issue of the 20 MW size cap, and should a different determination  
19 be reached either in the development of the MIP or independently of the MIP,  
20 PG&E may propose changes to the CMEP to address it.

### 21 **C. Eligibility Criteria**

22 PG&E designed the CMEP in order to support those communities and  
23 customers most in need of resilience. As such, the program's eligibility criteria  
24 for access to the CMET and cost offsets includes a requirement that at least one  
25 customer served by the microgrid be located either in a Tier 2/3 High Fire Threat  
26 District, or in an area that has been impacted by a Public Safety Power Shutoff  
27 (PSPS) event, or in an area prone to outages, defined for this purpose as the top  
28 1 percent Worst Performing Circuits excluding Major Event Days, from PG&E's  
29 Annual Electric Reliability Report, in either of the last two years. The program

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4 D.21-01-018, p.62.

5 Rulemaking19-09-009.

6 Advice Letter 5918-E, p.12.

1 also requires the project to serve at least one critical facility and one additional  
2 customer within the electrical boundary of the microgrid.

3 It is important to note that the tools and resources available through the  
4 Community Resilience website, as well as Stage 1 of CMEP's Enhanced  
5 Technical Support ("Project Vetting") are open to communities seeking energy  
6 resilience solutions of any kind. The locational eligibility criteria noted above do  
7 not apply to this initial concept exploration stage. As such, all communities in  
8 PG&E's service area are eligible for some form of CMEP support.

9 PG&E notes that the Joint Community Choice Aggregators (CCAs) in their  
10 Protest of AL 5918-E argued that the exclusion from CMEP of areas in which  
11 there is no reasonably anticipated potential future PSPS events due to other  
12 PSPS mitigation activities is too vague and will be challenging to implement.  
13 While PG&E stands by the assertion it made in its reply that criteria such as this  
14 are highly dynamic and not feasibly reduced to static map layers for all of  
15 PG&E's service area, this is an area that may warrant further scrutiny.

16 Finally, PG&E notes that it has encountered communities and customers  
17 which wish to use the CMET in order to operate a multi-customer microgrid,  
18 even if those community microgrid projects would be deemed ineligible for the  
19 CMEP cost offsets. While PG&E believes it is generally prudent to focus limited  
20 customer dollars on those communities with the greatest resilience need, it  
21 acknowledges that eligibility for the tariff itself, separate from the cost offsets,  
22 warrants further evaluation. In particular, PG&E intends to seek collaborative  
23 solutions, based upon the CMET, for these community microgrid projects that  
24 would allow them to move forward while pending the Commission's broader  
25 consideration of a multi-property microgrid tariff in Track 4 of the Microgrid and  
26 Resiliency Strategies OIR.

#### 27 **D. Application Process**

28 As described in PG&E's [CMEP Resilience Planning Guide](#), PG&E has  
29 developed a 3-stage, 11-step process to support community resilience project  
30 development, from initial concept exploration, through solution assessment, to  
31 solution execution. Step 5 in that process is the CMEP Application. The  
32 Application step is timed in such a way that the community and its  
33 technical/engineering partner(s) will have had detailed technical exchanges with  
34 PG&E regarding the protocols and requirements necessary to operate a

1 community microgrid on PG&E's distribution system, and the specific constraints  
2 and requirements of the proposed project. The applicant will have the  
3 information necessary to submit a high-quality interconnection application as  
4 well as CMEP Application.

5 The CMEP Application simply synthesizes the information developed in the  
6 previous stages. The objective of the Application is to provide PG&E the  
7 required information to assess the proposed project for CMEP eligibility and  
8 review documentation required to perform the Microgrid Islanding Study (MIS)  
9 pursuant to the CMEP.

10 At this time, PG&E believes the CMEP Application process is well-placed in  
11 the progression of development of a community microgrid. The applicant is  
12 supported through every step of the process before and after the Application,  
13 and the Application itself merely synthesizes project design information garnered  
14 through earlier stages in the process.

15 PG&E notes that some refinement may be necessary to the required 30-day  
16 timing for review of the Interconnection Study and agreement to proceed with a  
17 MIS. In those cases when multiple interconnection applications have been  
18 submitted for the same microgrid, the Community Microgrid Aggregator may be  
19 unable to make an informed decision about the wisdom of proceeding with a  
20 MIS until it has all of the relevant studies completed with their associated cost  
21 and timeline information. PG&E will further evaluate this issue in development  
22 of the MIP.

23 **E. Cost Offset Reservation Trigger**

24 The trigger for confirming and reserving cost offsets in the CMEP process is  
25 completion of the MIS, and execution of the Project Special Facilities  
26 Agreement. Reserving cost offsets at this point in the process provides a level  
27 of assurance that the applicant has an operationally safe microgrid design that  
28 can integrate within PG&E's distribution system. Further, the Project Special  
29 Facilities Agreement will provide detailed cost estimates for the CMEP-eligible  
30 distribution upgrades necessary to enable the safe islanding of the microgrid;  
31 that is, those upgrades which will be paid for by CMEP cost offsets.

32 At this time, PG&E sees no need to alter the timing of the trigger for  
33 reservation of cost offsets, or to suggest an alternate trigger. PG&E suggests  
34 the cost offset reservation trigger remain as it is currently and continue to

1 evaluate the placement along with other criteria as the program gains further  
2 experience.

### 3 **F. Outreach Plan Feedback**

4 On May 3, 2021, in conformance with Ordering Paragraph 4 of Res.E-5127,  
5 PG&E provided its CMEP Outreach Plan for Disadvantaged and Vulnerable  
6 Communities to the Energy Division's Central Files and made the plan publicly  
7 available on PG&E's CMEP website. As described in that plan, PG&E will begin  
8 with preparation and initial outreach in Quarter 2 2021, focused on preparing  
9 messaging, identifying potential partner agencies and organizations, and  
10 identifying complementary sources of resilience funding, where possible.

11 PG&E has had limited time to execute this plan and receive feedback on it.  
12 With that said, PG&E has already begun conversations with some  
13 community-based organizations, CCAs, and rural and tribal communities, to  
14 learn more about their local needs and desires in regard to energy resilience,  
15 and the challenges they are facing. These continuing conversations will inform  
16 PG&E's outreach to facilitate awareness among disadvantaged and vulnerable  
17 communities of the CMEP as well as of other potential resilience funding  
18 sources and opportunities. The feedback at this time to PG&E's initial  
19 conversations as part of this outreach plan have been positive.

### 20 **G. Summary**

21 In summary, while the CMEP was only fully approved in March 2021, PG&E  
22 is able to provide an initial program evaluation based on its engagement with  
23 customers and communities thus far under the program. PG&E will share its  
24 lessons learned through the CMEP as part of the MIP development process in  
25 order to help inform the development of that program. Finally, PG&E may  
26 propose changes to the CMEP to more fully integrate it with the MIP, as  
27 authorized in D.21-01-018,<sup>7</sup> or separately through the submission of a separate  
28 advice letter.<sup>8</sup>

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7 D.21-01-018, p.62.

8 Advice Letter 5918-E, p. 15, fn. 23 (approved by Resolution E-5127).

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 22**  
**ELECTRIC DISTRIBUTION SUPPORT ACTIVITIES**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 22  
ELECTRIC DISTRIBUTION SUPPORT ACTIVITIES

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1                                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2   **CHAPTER 22**  
3                                   **ELECTRIC DISTRIBUTION SUPPORT ACTIVITIES**

4   **A. Introduction**

5       **1. Scope and Purpose**

6                   The purpose of this chapter is to demonstrate that Pacific Gas and  
7                   Electric Company's (PG&E or the Company) expense and capital  
8                   expenditure forecasts for electric distribution support activities are  
9                   reasonable and should be approved.

10                  This chapter includes forecasts for four expense Major Work Categories  
11                  (MWC) – MWC AB (Miscellaneous Expense), MWC IS (Streetlight Support),  
12                  MWC OM (Operational Management), and MWC OS (Operational Support)  
13                  – and two capital MWCs – 05 (Tools and Equipment), and  
14                  21 (Miscellaneous Capital).<sup>1</sup>

15       **2. Summary of Request**

16                  PG&E requests that the Commission adopt its 2023 expense forecast of  
17                  \$131.6 million for Electric Distribution Support Activities, which is  
18                  \$32.4 million higher than 2020 recorded expense costs of \$99.2 million.<sup>2</sup>

19                  PG&E further requests that the Commission adopt its capital forecast of  
20                  \$(18.3) million for 2021, \$10.7 million for 2022, \$8.4 million for 2023,  
21                  \$8.6 million for 2024, \$8.8 million for 2025, and \$9.0 million for 2026 for  
22                  capital expenditures for electric distribution support activities.<sup>3</sup> PG&E's  
23                  2023 capital forecast for electric distribution support is \$0.4 million higher  
24                  than its 2020 recorded expenditures of \$8.0 million.

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1   In the 2020 General Rate Case (GRC), the Electric Distribution Support Activities chapter also included a forecast for MWC GE (Electric Distribution Mapping). For the 2023 GRC, the MWC GE forecast can be found in Exhibit (PG&E-4), Ch. 20, Electric Distribution Data Management and Technology. This movement aligns with Electric Operations' (EO) organizational structure.

2   Exhibit (PG&E-4), WP 22-1, line 5.

3   Exhibit (PG&E-4), WP 22-15, line 3.

1 Forecasts in this chapter are shown with escalation at the MWC level  
 2 and escalation is included in all expense and capital totals. For more  
 3 information on escalation, please refer to Chapter 2 of this exhibit.

### 4 **3. Overview of Recorded and Forecast Costs**

5 PG&E uses the MWCs shown in Table 22-1 to record Distribution  
 6 Support Activities expenditures for capital and expense. Work in this  
 7 chapter is not further subdivided into Maintenance Activity Type (MAT)  
 8 codes.

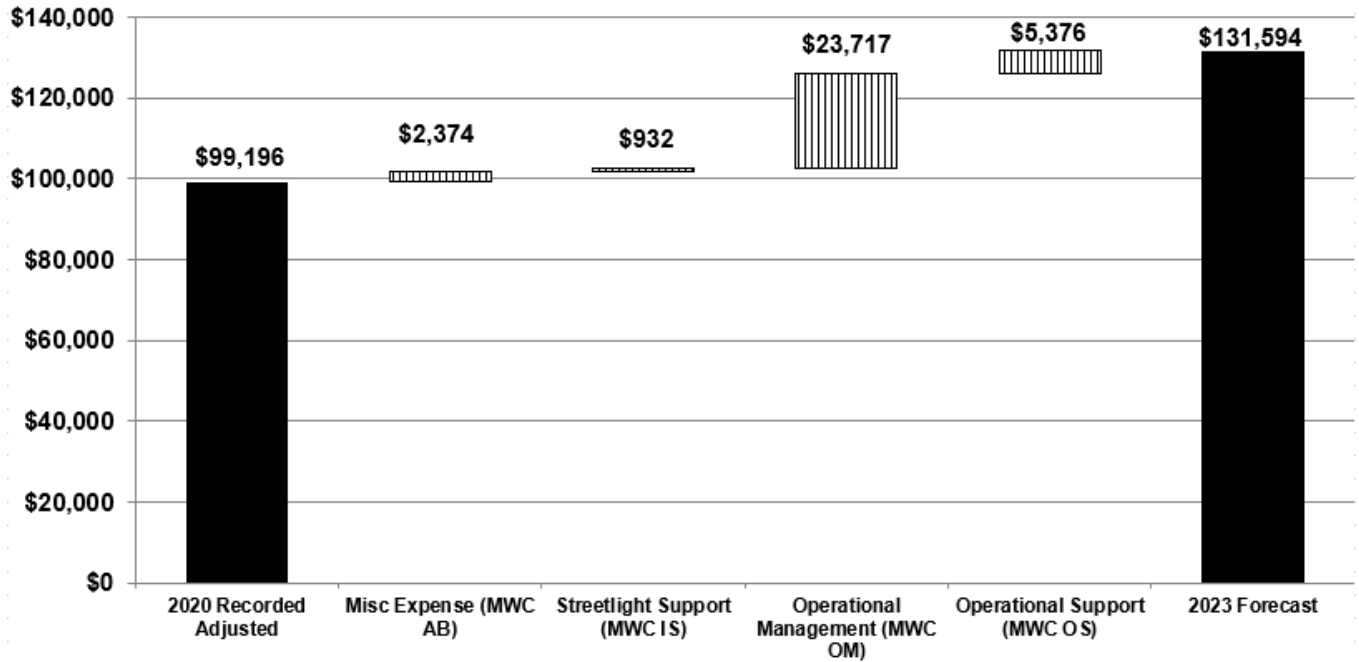
**TABLE 22-1**  
**DISTRIBUTION SUPPORT ACTIVITIES MWC**

Line No.	MWCs	Description
1	<u>Expense MWCs</u>	
2	AB	Miscellaneous Expense
3	IS	Streetlight Support
4	OM	Operational Management
5	OS	Operational Support
6	<u>Capital MWCs</u>	
7	05	Tools and Equipment
8	21	Miscellaneous Capital

#### 9 **a. Expense**

10 Figure 22-1 shows the changes between PG&E's 2020 recorded  
 11 costs and its 2023 expense forecast. The main increases from 2020  
 12 recorded amounts are in MWCs AB and OS. These increases are  
 13 mainly driven by headcount to support the Regulatory Compliance &  
 14 Quality Assurance (QA) group in MWC AB, and increased headcount in  
 15 MWCs OM and OS to support a larger portfolio of Electric Distribution  
 16 work.

**FIGURE 22-1  
EXPENSE WALK BY MWC (2020-2023)  
(THOUSANDS OF NOMINAL DOLLARS)**

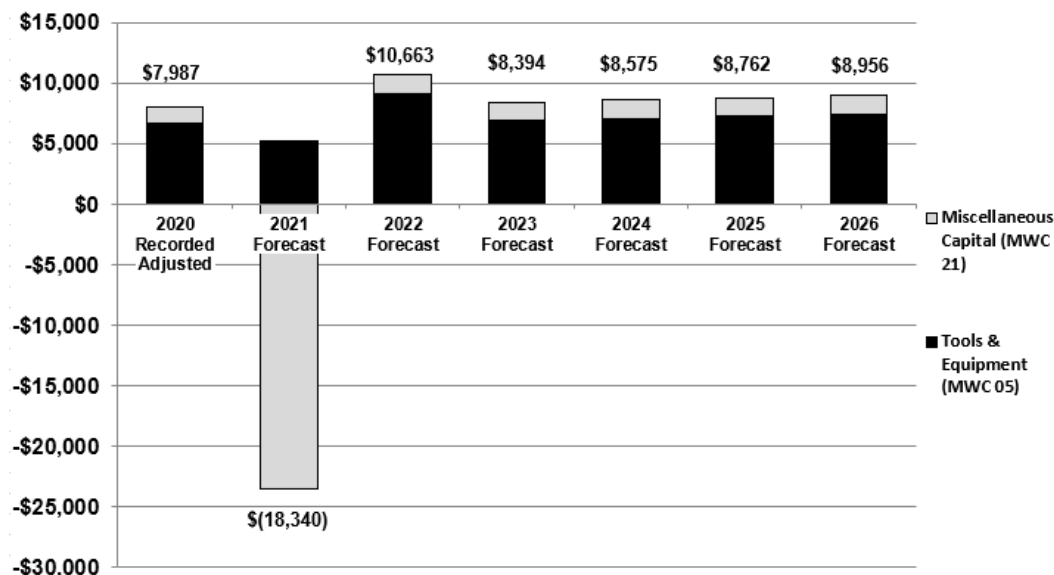


1  
2  
3

**b. Capital**

Figure 22-2 below shows PG&E's 2020 recorded expenditures and its 2021 to 2026 capital forecast.

**FIGURE 22-2  
CAPITAL RECORDED AND FORECAST BY MWC 2020-2026<sup>(a)</sup>  
(THOUSANDS OF NOMINAL DOLLARS)**



(a) The 2021 forecast of \$(18.3) million is comprised of a positive forecast of \$5.2 million in MWC 05 and a negative amount of \$23.5 million in MWC 21.

1                   The increase in MWC 05 between 2020 and 2023 is mainly driven  
 2                   by Capital Tools for Substation, Major Projects & Programs, and  
 3                   Distribution Line Technicians. The expenditures in MWC 21 are directly  
 4                   related to costs of upgrades to PG&E's Applied Technology Services  
 5                   (ATS) Lab. The negative number shown in 2021 represents cross-MWC  
 6                   affordability savings discussed in Section C.2.b.2 of this chapter.

#### 7                   **4. Support for Request**

8                   PG&E's Electric Distribution Support forecast includes the following  
 9                   activities that are necessary for the overall operation, development, and  
 10                  maintenance of the electric distribution system:

- 11                  • Costs to support the execution of the electric distribution work plans and  
 12                  provide important public safety services such as the public safety  
 13                  outreach program; and
- 14                  • Operational support and management costs to provide necessary  
 15                  structure and coordination for the execution of all electric distribution  
 16                  activities from outage restoration efforts to long term infrastructure  
 17                  improvements.

## 5. Organization of the Remainder of This Chapter

The remainder of this chapter is organized as follows:

- Section B – Program and Risk Overview;
- Section C – Activities, Costs, and Forecast Drivers by MWC;
- Section D – Estimating Method;
- Section E – Compliance with Section 5.2 of the 2020 GRC Settlement Agreement (“Deferred Work Principles”); and
- Section F – Cost Tables.

### B. Program and Risk Overview

#### 1. Program Description

##### a. Program Overview

Distribution Support Activities enable the safe and efficient execution of distribution work across EO programs. MWCs AB and 21 cover expense and capital expenditure forecasts, respectively, for programs not easily captured by other MWCs. This includes activities such as service contracts with third parties, asset data and risk model improvements, PG&E’s internal energy use, costs related to PG&E’s ATS workstream, and regulatory and QA efforts. MWC IS covers expenses related to streetlight audit activity. MWC OM reflects the costs of direct supervision of field execution resources. MWC OS reflects the costs of organizations that support the enablement and execution of field work (e.g., work planning, clerical, scheduling). MWC 05 covers the purchase of tools to provide employees the equipment needed to effectively complete electric distribution work.

##### b. Management Structure

Many of the miscellaneous support activities discussed in this chapter are woven throughout the EO organization. For example, MWCs AB and 21 do not have a separate management structure associated with them but are instead monitored and controlled by the Electric Business Operations Department. Similarly, forecasts for MWCs OM and OS represent support and management staffing for various departments throughout EO.

1 The ATS organization, which drives a portion of the expenditures in  
 2 MWCs AB, 05, and 21, is part of PG&E's Asset Risk Management  
 3 (ARM) Department in the EO organization. Although ATS is situated in  
 4 the EO organization, ATS is a shared internal resource providing  
 5 services to multiple PG&E organizations. The Streetlight Support  
 6 Program, which drives MWC IS expenditures, is also a part of the ARM  
 7 department.

## 8 2. Risk Integration

9 Risk controls and mitigations are aligned to various MWCs and MATs in  
 10 Electric Distribution. This chapter includes the forecast for two risk  
 11 mitigations that are described in chapter 3. The recorded and forecast costs  
 12 for these mitigations are shown in Table 22-2 below.<sup>4</sup> More information  
 13 about risk mitigations and controls can be found in PG&E's Electric  
 14 Distribution Risk Management testimony, Exhibit (PG&E-4), Chapter 3.

**TABLE 22-2**  
**FAILURE OF ELECTRIC DISTRIBUTION OVERHEAD ASSETS**  
**FORECAST MITIGATIONS**  
**RECORDED ADJUSTED AND FORECAST COSTS (2020-2023)**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Mitigation No.	Mitigation Name	MAT	2020 Recorded Adjusted	Forecast			Total
					2021	2022	2023	
1	DOVHD-M005	Additional Asset Data Captures	AB#	-	-	\$1,269	\$1,297	\$2,566
2	DOVHD-M009	Improved Distribution Risk Model	AB#	-	-	1,473	1,513	2,986
3		Total		-	-	\$2,742	\$2,810	\$5,553

<sup>4</sup> Exhibit (PG&E-4), WP 3-10, line 34.

## 1 C. Activities, Costs, and Forecast Drivers by MWC

### 2 1. Expense MWCs

#### 3 a. Miscellaneous Expense (MWC AB)

4 PG&E's 2023 forecast for Miscellaneous Expenses in MWC AB is  
5 \$49.5 million.<sup>5</sup> The components of this forecast are described below.<sup>6</sup>

#### 6 1) Distribution Support

7 Distribution Support encompasses general support of the  
8 electric distribution system and several smaller programs such as  
9 Electric Asset Excellence, as well as miscellaneous expenses such  
10 as consulting, industry association dues, and easement costs.

11 PG&E's forecast is \$19.3 million for 2023, which is \$7.8 million  
12 lower than 2020 recorded expenditures of \$27.1 million.<sup>7</sup> The  
13 primary driver for this variance is due to a reduction in  
14 contract/consulting costs.

#### 15 2) Applied Technology Services

16 ATS provides miscellaneous support to departments within  
17 Electric Distribution Operations to ensure compliance with

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5 See Exhibit (PG&E-4) WP 22-11, line 10.

6 In the 2020 GRC, PG&E forecast two activities in MWC AB in the Electric Distribution Support Activities chapter that are no longer included in this chapter for the 2023 GRC period. The first activity was the CWSP PMO; the recorded costs and 2023 GRC forecast for the CWSP PMO are now discussed along with other wildfire risk mitigations in Exhibit (PG&E-4), Ch. 4. The second activity was for Paid Time Off (PTO), Indirect Labor, and Material Burden Overheads (OH) that PG&E no longer allocates to balancing account or Catastrophic Event Memorandum Account orders due to a change in PG&E's cost model. In the 2020 GRC, PG&E forecast these costs in MWC AB because there was no historical precedent for how much the methodology change would impact specific expense MWCs, but noted that in future GRCs it would allocate the expense portion of these OH costs to the specific expense MWCs in the Electric Distribution exhibit where they are ultimately incurred. A.18-12-009, HE-17: Exhibit (PG&E-4), p. 18-18, lines 9-29. As a result, there will be no 2020-2022 recorded costs for these OHs in MWC AB, and there is no 2023 forecast for these OHs in MWC AB in the 2023 GRC.

7 See Exhibit (PG&E-4) WP 22-11, line 1.

1 regulations and the safe and reliable operations of our assets.<sup>8</sup>

2 Examples of these services include:

- 3 • Dielectric Truck Testing;
- 4 • Instrument Calibration and Repair;
- 5 • Failure Analysis and Incident Investigation; and
- 6 • Electric Magnetic Fields (EMF) Program<sup>9</sup>

7 PG&E's 2023 forecast for ATS Electric Distribution Support  
8 activities is \$3.4 million, which is \$1.0 million lower than 2020  
9 recorded expenses of \$4.4 million.<sup>10</sup>

10 **3) Additional Asset Data Capture (DOVHD-M005)**

11 This risk mitigation addresses the Failure of Electric Distribution  
12 OH Assets risk.<sup>11</sup> This program is discussed in greater detail in  
13 Exhibit (PG&E-4), Chapter 3.

14 PG&E's 2023 forecast for Additional Asset Data Capture is  
15 \$1.3 million. This is a new program, so PG&E had no recorded  
16 expenses in 2020.<sup>12</sup>

17 **4) Improved Distribution Risk Model (DOVHD-M009)**

18 This risk mitigation addresses the Failure of Electric Distribution  
19 OH Assets risk. This program is discussed in greater detail in  
20 Exhibit (PG&E-4), Chapter 3.

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<sup>8</sup> ATS also provides support services to other PG&E lines of business (e.g., Gas, Hydro Generation, Customer Care, and Transmission). The forecast discussed in this chapter is for the portion of ATS Support Expenses performed for Electric Distribution.

<sup>9</sup> The EMF program was discussed as a separate line item in the 2020 GRC but has been consolidated with other ATS support activities here because of the relatively small size of the forecast. For a further discussion of the EMF program, see A.18-12-009, HE-17: Exhibit (PG&E-4), p. 18-15, line 23 to p. 18-16, line 9.

<sup>10</sup> See (PG&E-4) WP 22-11, line 2.

<sup>11</sup> See PG&E's 2020 RAMP Report, A.20-06-012 (June 30, 2020), p. 11-24, lines 3-16.

<sup>12</sup> See Exhibit (PG&E-4) WP 22-11, line 3, and WP 3-10, line 27 (DOVHD mitigations, expense).

1 PG&E's 2023 forecast for the Improved Distribution Risk Model  
2 is \$1.5 million.<sup>13</sup> PG&E did not track costs separately for this work  
3 in 2020 but will do so going forward.

4 **5) Federal Land Authorization**

5 In 2019, PG&E executed a 30-year Master Special Use Permit  
6 and Master Operations and Maintenance Plan (MSUP) with the  
7 Pacific West Region of the United States Forest Services (USFS),  
8 Region 5. The MSUP renewed approximately 140 expired land  
9 authorizations and consolidated the remaining land authorizations  
10 into two permits/easement. The MSUP also formalizes how PG&E  
11 should interact with the USFS on routine operations and  
12 maintenance activities. As a condition of the MSUP, PG&E is  
13 obligated to perform some road improvements and cultural and  
14 biological compliance activities. PG&E's 2023 expense forecast for  
15 these activities stemming from the MSUP is \$3.5 million<sup>14</sup>, which is  
16 \$1.3 million lower than 2020 recorded expenses of \$4.8 million.<sup>15</sup>

17 **6) Interdepartmental Energy Usage**

18 Interdepartmental energy usage is the cost associated with  
19 natural gas or electricity that is used at PG&E electric distribution  
20 facilities (essentially metered natural gas or electricity that is used  
21 by and billed to the business).

22 The forecast is \$2.9 million for 2023, which is \$0.2 million higher  
23 than 2020 recorded expenses of \$2.7 million<sup>16</sup>.

24 **7) Regulatory Compliance and QA Group**

25 MWC AB includes a forecast for the Electric Distribution line of  
26 business' share of costs related to headcount for the Regulatory

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**13** See Exhibit (PG&E-4) WP 22-11, line 4, and WP 3-10, line 28 (DOVHD mitigations, expense).

**14** See Exhibit (PG&E-4) WP 22-11, line 5.

**15** PG&E anticipates that there may also be some capital expenditures associated with work stemming from the MSUP. PG&E has not included a capital forecast for this work in the 2023 GRC. If the work becomes necessary, PG&E will reprioritize other work to accomplish it.

**16** See Exhibit (PG&E-4) WP 22-11, line 6.

1 Compliance and QA Group.<sup>17</sup> This group was created in 2019 and  
2 combines and significantly expands several functions related to EO  
3 regulatory compliance and QA. These functions include:

- 4 • Electric Incident Investigation Team: This team performs  
5 investigations of CPUC-reportable electric incidents and  
6 wildfire ignitions related to PG&E facilities, submits 20-day  
7 reports, and provides follow-up data to the Commission.
- 8 • Corrective Action Program (CAP): The CAP Team  
9 receives, ranks, organizes, and tracks corrective actions  
10 from receipt through closure. The CAP Team also performs  
11 cause evaluations for electric issues, serious injuries and  
12 fatalities, and other safety matters. Its scope has recently  
13 been expanded to include evaluations of other activities that  
14 PG&E considers non-complaint or potentially non-compliant.
- 15 • Electric Data Response Unit (EDRU): The EDRU, which  
16 was separately forecast in the 2020 GRC, coordinates  
17 responses to data requests to the EO business unit.
- 18 • Compliance Group: This group supports CPUC and Wildfire  
19 Safety Division regulatory audits, provides compliance  
20 guidance, and responds to Notices of Violation from  
21 regulators.
- 22 • Quality Team: This team performs quality management  
23 services including quality verification, QA, and other audits.

24 PG&E's 2023 forecast for the Electric Distribution portion of the  
25 costs for the Regulatory Compliance and QA group is \$17.1 million,  
26 which is \$9.4 million higher than 2020 recorded expenses of  
27 \$7.7 million.<sup>18</sup> The reason for the increase is additional headcount

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<sup>17</sup> The Regulatory Compliance and QA Group performs work for both the Electric Distribution and Electric Transmission lines of business. Costs are allocated based on how resources support the various workstreams across Electric Operations. In addition, PG&E considers some costs from this group to be wholly related to Wildfire risk mitigation and, beginning in Q2 2021, the Regulatory Compliance and QA Group will be directly charging to FRMMA/WMPMA orders for activities that qualify as incremental and directly related to wildfire mitigation.

<sup>18</sup> See Exhibit (PG&E-4) WP 22-11, line 7.

1 to address the increase in data requests from regulators, intervenors  
2 and observers, increased self-reports of non-conformance or  
3 potential non-conformance, a maturing incident investigation  
4 process, a significantly strengthened quality management program,  
5 enhancements to the compliance management program, and  
6 increased compliance governance.

#### 7 **8) Public Awareness Outreach**

8 PG&E's 2020 RAMP Report<sup>19</sup> included an estimate of costs  
9 associated with public outreach and messaging to control and  
10 mitigate the Failure of Electric Distribution OH Assets risk. This  
11 includes funding for the additional bill insert details and public safety  
12 messages described in PG&E's 2020 RAMP report. The forecast  
13 for public outreach, including the additional outreach for the Failure  
14 of Electric Distribution OH Assets risk, is \$0.6 million for 2023, which  
15 is \$0.2 million higher than 2020 recorded expenditures of  
16 \$0.4 million.<sup>20</sup>

#### 17 **9) Affordability**

18 In 2021 and 2022, PG&E is forecasting cross-MWC affordability  
19 initiative savings related to expense programs in MWC AB. PG&E  
20 is forecasting \$44.2 million of such savings in 2021 and  
21 \$38.9 million in 2022.<sup>21</sup> These cost savings amounts are in  
22 addition to the savings embedded in the expense forecasts in other  
23 chapters in this exhibit, and will be realized in MWCs other than  
24 AB.<sup>22</sup>

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**19** PG&E's 2020 RAMP Report, A.20-06-012 (June 30, 2020).

**20** See Exhibit (PG&E-4) WP 22-11, line 8.

**21** See Exhibit (PG&E-4) WP 22-11, line 9.

**22** As explained in Exhibit (PG&E-2) Ch. 3, PG&E prepared its 2023 GRC forecast, starting first with the Plan of Reorganization forecast for the work included in the 2023 GRC and then adding updates to address company-wide work needs and priorities, risk mitigations, and cost-savings initiatives. Through the process of prioritizing the Electric Distribution portfolio and in accordance with the 2023 GRC forecast guidelines outlined in Exhibit (PG&E-2) Ch. 3, this forecast prioritizes funding for the most critical work and incorporates a cost-savings initiative which is identified as a reduction to the forecast. EO's work portfolio planning and prioritization process is discussed further in Exhibit (PG&E-4) Ch. 2.

1 **10) MWC AB Forecast Summary**

2 Table 22-3 summarizes the forecast for MWC AB.

**TABLE 22-3**  
**MWC AB FORECAST SUMMARY**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Distribution Support	\$27,071	\$23,660	\$17,830	\$19,266	WP 22-11, line 1.
2	ATS Services	4,406	3,199	3,297	3,389	WP 22-11, line 2.
3	Additional Asset Data Capture	-	-	1,269	1,297	WP 22-11, line 3.
4	Improved Distribution Risk Model	-	-	1,473	1,513	WP 22-11, line 4.
5	Federal Land Authorization	4,823	4,348	4,174	3,454	WP 22-11, line 5.
6	Interdepartmental Energy Usage	2,702	2,700	2,783	2,870	WP 22-11, line 6.
7	Regulatory Compliance and QA	7,736	16,106	16,599	17,119	WP 22-11, line 7.
8	Public Awareness Outreach	399	566	583	602	WP 22-11, line 8.
9	Affordability	-	(44,214)	(38,853)	-	WP 22-11, line 9.
10	Total	\$47,137	\$6,365	\$9,155	\$49,510	WP 22-11, line 10.

3 **b. Streetlight Support (MWC IS)**

4 Support costs associated with billing for streetlights are recorded in  
5 MWC IS. The work includes field inventory audits to verify billing, and to  
6 verify ownership of streetlights to aid in the billing process. PG&E's  
7 2023 forecast for this program is \$1.6 million, which is \$0.9 million  
8 higher than its 2020 recorded costs of \$0.7 million, due to the increase  
9 in those areas that have had substantial growth and where past  
10 inventories have not been completed.<sup>23</sup> Table 22-4 summarizes the  
11 forecast for MWC IS.

<sup>23</sup> See Exhibit (PG&E-4) WP 22-11, line 11.

**TABLE 22-4**  
**MWC IS FORECAST SUMMARY**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Streetlight Support	\$709	\$862	\$864	\$1,641	WP 22-11, line 11.
2	Total	\$709	\$862	\$864	\$1,641	

**c. Operational Management (MWC OM) and Operational Support (MWC OS)**

MWCs OM and OS represent the costs to supervise, support or manage PG&E personnel who charge their time directly to orders. MWC OM reflects the costs of direct supervision of field execution resources, while MWC OS reflects the costs of organizations that support the enablement and execution of field work (e.g., work planning, clerical, scheduling).<sup>24</sup>

Historically these management and support costs were included as a part of the field resources direct labor rate and referred to as “Supervision and Management.” In 2016, PG&E revised its cost model; this revision created new overheads, including those recorded in MWC OM and OS, in lieu of the traditional “fully burdened” cost approach. From 2016 to 2019, PG&E allocated a portion of these MWC OM and OS costs to non-expense (capital and balancing/memorandum account expense) orders each month, based on internal labor charges incurred in those orders. The portion of MWC OM and OS costs not allocated to non-expense orders remained in base expense.

As described in its 2020 GRC filing, PG&E has implemented an additional change to its cost model. Beginning in 2020, PG&E no longer allocates MWC OM or OS overhead to GRC balancing/memo account expense orders (though it still allocates this overhead to capital orders). This change increases the proportion of MWC OM and OS costs that

<sup>24</sup> Pursuant to CPUC Resolution E-4963 (Dec. 14, 2018), PG&E has excluded from its 2023 forecast the salary and benefits of the utility’s SEC Rule 240.3b-7 officers. PG&E has also voluntarily excluded from its 2023 forecast the salary and benefits of the PG&E Corporation’s SEC Rule 240.3b-7 officers although not required by the Resolution. See Exhibit (PG&E-8), Ch. 4 for further discussion of officer compensation costs.

1 remain in base expense (with a corresponding decrease in the  
2 proportion of MWC OM and OS costs that will be forecast in/allocated to  
3 non-expense orders).

4 PG&E's 2020 recorded costs and 2021 and 2022 forecast for MWC  
5 OM and OS are considerably higher than what was forecast in the 2020  
6 GRC or imputed from the 2020 GRC settlement. While PG&E  
7 attempted to model the incremental cost that would "move back to base  
8 expense" from balancing and memorandum account orders due to the  
9 change in its cost model, significant unanticipated growth in balancing  
10 and memorandum account expense spend and the associated support  
11 costs (both of which are driven by incremental wildfire mitigation work  
12 such as Enhanced Vegetation Management) will drive PG&E's actual  
13 MWC OM/OS spending for 2020-2022 well above imputed amounts  
14 from the 2020 GRC.

15 PG&E's 2023 forecast for MWCs OM and OS is \$80.4 million, which  
16 is \$29.0 million higher than 2020 recorded costs of \$51.4 million.<sup>25</sup> The  
17 drivers for the increase between 2020 recorded and the 2023 forecast  
18 are inclusion of OM/OS costs associated with work recorded to FRMMA  
19 in 2020<sup>26</sup> back into base expense, additional support headcount, and  
20 escalation. PG&E also anticipates significant growth in balancing and  
21 memorandum account expense spend in support of wildfire mitigation  
22 which, due to the cost model change described above, leads to  
23 additional OM/OS overhead being recorded to base spending.

24 Table 22-5 summarizes the forecast for MWC OM and OS.  
25 Additional detail can be found in WP Tables 22-11 and 22-13.

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<sup>25</sup> See Exhibit (PG&E-4) WP 22-11, line 14 and line 17.

<sup>26</sup> PG&E's methodology for allocating OM/OS expense to the FRMMA is described in Exhibit (PG&E-4) WP 22-14.

**TABLE 22-5**  
**MWC OM AND OS FORECAST SUMMARY**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	WP Reference
1	Operational Management	\$(4,204)	\$14,401	\$14,422	\$19,513	WP 22-11, line 14.
2	Operational Support	55,555	45,894	45,961	60,931	WP 22-11, line 17.
3	Total	\$51,351	\$60,295	\$60,383	\$80,443	

1        **2. Capital MWCs**

2        **a. Tools and Equipment (MWC 05)**

3                PG&E’s forecast for Tools and Equipment (MWC 05) is \$5.2 million  
4                in 2021, \$9.2 million in 2022, \$6.9 million in 2023, \$7.1 million in 2024,  
5                \$7.3 million in 2025, and \$7.5 million in 2026.<sup>27</sup> The components of the  
6                forecast are described below.

7                **1) General Tools**

8                MWC 05 includes the cost of tools and test equipment used by  
9                Maintenance, Construction, Substation, Test, and Restoration  
10                employees to perform distribution-related work.<sup>28</sup> These  
11                expenditures are needed to provide ergonomically safe tools and  
12                equipment; to replace damaged, worn out, or obsolete tools and test  
13                equipment; to have specialized tools available to install, test,  
14                remove, or diagnose all types of equipment currently in service; and  
15                to acquire the new tools and test equipment needed to safely  
16                operate and maintain next generation devices and assets being  
17                installed on the grid.

18                PG&E’s 2023 capital expenditure forecast for general tools is  
19                \$6.0 million, which is \$1.6 million higher than 2020 recorded

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<sup>27</sup> See Exhibit (PG&E-4) WP 22-15, line 1.

<sup>28</sup> MWC 05 forecast incorporates new tools and learnings from EPIC project 1.09A “Close Proximity Switching.” In order to reduce public and employee safety risk, project objectives were to develop, test, and compare new tools and techniques to operate underground oil-filled switches remotely, including the parts and adapters necessary required to support various types (manufacturer, brand, age) of switches. PG&E’s tool purchasing program now incorporates the findings of this project into their tool purchasing strategy to improve safety.

1 expenditures of \$4.4 million<sup>29</sup>. The increase is due to tool  
2 purchases to support Substation, Major Projects and Programs ,  
3 and Distribution Line Technicians. PG&E's forecast for 2021 is  
4 \$2.0 million, for 2022 is \$5.8 million, for 2024 is \$6.1 million, for  
5 2025 is \$6.3 million, and for 2026 is \$6.5 million.

6 **2) ATS Tools**

7 Capital expenditures in MWC 05 are needed so that ATS  
8 employees performing field and laboratory tests have appropriate  
9 tools and test equipment. Regular expenditures are necessary to  
10 replace damaged, worn out, or obsolete tools and to provide  
11 specialized tools to perform testing and other analytical functions.

12 PG&E's 2023 forecast for this work is \$0.9 million<sup>30</sup>, which is  
13 similar to its 2020 recorded expenditures.<sup>31</sup>

14 **3) MWC 05 Forecast Summary**

15 Table 22-6 summarizes the forecast for MWC 05.  
16

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**29** See Exhibit (PG&E-4) WP 22-22, line 1.

**30** See Exhibit (PG&E-4) WP 22-22, line 2.

**31** In the 2020 GRC, MWC 05 also included a forecast for capital work related to the ATS High Voltage Dome lab. A.18-12-009, HE-17: Exhibit (PG&E-4) p. 18-25, line 24 to p. 18-26, line 14. PG&E is not requesting any funding for that activity in this GRC.

**TABLE 22-6**  
**MWC 05 FORECAST SUMMARY**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	General Tools	\$4,426	\$1,983	\$5,837	\$5,960	\$6,125	\$6,295	\$6,472	WP 22-22, line 1
2	ATS Tools	857	920	934	941	954	968	983	WP 22-22, line 2
3	ATS Capital Lab Project	—	2,300	2,397	—	—	—	—	WP 22-22, line 3
4	Federal Land Authorization	1,428	—	—	—	—	—	—	WP 22-22, line 4
5	Total	\$6,711	\$5,203	\$9,167	\$6,901	\$7,079	\$7,263	\$7,455	WP 22-22, line 6

1           **b. Miscellaneous Capital (MWC 21)**

2                   PG&E's forecast for Miscellaneous Capital (MWC 21) is  
3                   \$(23.5) million in 2021, \$1.5 million in 2022, \$1.5 million in 2023,  
4                   \$1.5 million in 2024, \$1.5 million in 2025, and \$1.5 million in 2026.<sup>32</sup>  
5                   The components of the forecast are described below.<sup>33</sup>

6           **1) ATS Lab Safety and Reliability Upgrades**

7                   In order to stay up-to-date on evolving technologies and testing  
8                   techniques, PG&E needs to make ongoing facility and operating  
9                   equipment upgrades at the ATS testing laboratories located at the  
10                  San Ramon Technology Center. ATS has 10 technical work units  
11                  providing a variety of testing services. Testing takes place in more  
12                  than a dozen distinct laboratories that require safety and reliability  
13                  upgrades. Lab upgrades in the 2023-2026 timeframe will be  
14                  prioritized based on the most pressing needs of the company which  
15                  are expected to include increased failure analysis testing, new  
16                  technology testing related to Wildfire risk mitigation, and asset  
17                  evaluations.

18           **2) Affordability**

19                  As discussed above, similar to expense, PG&E is forecasting  
20                  cross-MWC, capital program-related affordability initiative savings in  
21                  MWC 21. PG&E is forecasting \$25.0 million of such savings in  
22                  2021.<sup>34</sup>

23           **3) MWC 21 Forecast Summary**

24                  Table 22-7 summarizes the forecast for MWC 21.

---

<sup>32</sup> See Exhibit (PG&E-4) WP 22-15, line 2.

<sup>33</sup> In the 2020 GRC, PG&E forecast some costs associated with PTO, Indirect Labor and Material Burden OH in MWC 21 in the Electric Distribution Support Activities chapter. As with the expense portion of these costs described in footnote 7, above, these OH costs are no longer included in this chapter for the 2023 GRC period because they will be allocated to the specific expense MWCs in the Electric Distribution exhibit where they are ultimately incurred. A.18-12-009, HE-17: Exhibit (PG&E-4), p. 18-27, line 13 to page 18-28, line 13.

<sup>34</sup> See Exhibit (PG&E-4) WP 22-22, line 9.

**TABLE 22-7**  
**MWC 21 FORECAST SUMMARY**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast	2026 Forecast	WP Reference
1	ATS Lab Safety and Reliability Upgrades	\$1,195	\$1,458	\$1,496	\$1,493	\$1,496	\$1,499	\$1,502	WP 22-22, line 7.
2	External Contract Estimating Holding	81	-	-	-	-	-	-	WP 22-22, line 8.
3	Affordability	-	(25,000)	-	-	-	-	-	WP 22-22, line 9.
4	Total	\$1,276	\$(23,542)	\$1,496	\$1,493	\$1,496	\$1,499	\$1,502	WP 22-22, line 10.

1 **D. Estimating Method**

2 The workpapers accompanying this chapter provide specific details on cost  
3 estimation for each of the categories of work included.

4 **E. Compliance with Section 5.2 of the 2020 GRC Settlement Agreement**  
5 **(“Deferred Work Principles”)**

6 The 2020 GRC Settlement Agreement requires PG&E to include testimony  
7 in this GRC on deferred work if the following criteria are met:

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

14 Some of the work that was authorized in the 2020 GRC in this chapter is  
15 safety-related, however there was no work that met the criteria for deferred work  
16 as described in the Settlement Agreement. This analysis is presented in the  
17 workpapers supporting Chapter 2 of this Exhibit.<sup>35</sup>

18 **F. Cost Tables**

19 The expense and capital forecasts for Electric Distribution Support Activities  
20 are summarized in the following tables:

- 21 • Table 22-8 lists the expense MWCs, showing 2016 through 2020 recorded  
22 expenses and 2021 through 2023 forecast expenses; and  
23 • Table 22-9 lists the capital MWCs, showing 2016 through 2020 recorded  
24 expenditures and 2021 through 2026 forecast expenditures.

---

<sup>35</sup> See Exhibit (PG&E-4), Table WP 2-13, WP 2-15, line 1 through WP 2-16, line 16.

**TABLE 22-8  
EXPENSE  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast				WP Reference
			2016	2017	2018	2019	2020	2021	2022	2023	2024	
1	AB	Misc. Expense	\$20,000	\$13,429	\$19,118	\$16,151	\$47,137	\$6,365	\$9,155	\$49,510	WP 22-1, line 1	
2	IS	Streetlight Support	-	1,056	853	165	709	862	864	1,641	WP 22-1, line 2	
3	OM	Operational Management	17,068	18,408	5,274	12,407	(4,204)	14,401	14,422	19,513	WP 22-1, line 3	
4	OS	Operational Support	11,695	(212)	20,345	7,571	55,555	45,894	45,961	60,931	WP 22-1, line 4	
5		Total	\$48,763	\$32,681	\$45,591	\$36,294	\$99,196	\$67,522	\$70,401	\$131,594		

**TABLE 22-9  
CAPITAL  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast				WP Reference		
			2016	2017	2018	2019	2020	2021	2022	2023	2024		2025	2026
1	05	Tools and Equipment	\$9,335	\$5,778	\$7,209	\$7,532	\$6,711	\$5,203	\$9,167	\$6,901	\$7,079	\$7,263	\$7,455	WP 22-15, line 1
2	21	Misc. Capital	-	-	-	-	1,276	(23,542)	1,496	1,493	1,496	1,499	1,502	WP 22-15, line 2
3		Total	\$9,335	\$5,778	\$7,209	\$7,532	\$7,987	\$(18,340)	\$10,663	\$8,394	\$8,575	\$8,762	\$8,956	

**PACIFIC GAS AND ELECTRIC COMPANY**  
**CHAPTER 23**  
**COMMUNITY REBUILD PROGRAM**  
**[INCLUDES ERRATA THROUGH FEBRUARY 25, 2022 AND**  
**FEBRUARY 25, 2022 SUPPLEMENTAL TESTIMONY]**

PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 23  
COMMUNITY REBUILD PROGRAM  
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PACIFIC GAS AND ELECTRIC COMPANY  
CHAPTER 23  
COMMUNITY REBUILD PROGRAM

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1                                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2   **CHAPTER 23**  
3                                   **COMMUNITY REBUILD PROGRAM**

4   **A. Introduction**

5       **1. Scope and Purpose**

6                   The purpose of this chapter is to demonstrate that Pacific Gas and  
7                   Electric Company's (PG&E or the Company) expense and capital forecasts  
8                   for the Community Rebuild Program are reasonable and should be  
9                   approved. This chapter describes forecasts expenditures for the Community  
10                  Rebuild project for Electric Operations (EO), Gas Operations and Customer  
11                  Care.<sup>1</sup> In 2019, PG&E initiated the Community Rebuild Program to rebuild  
12                  PG&E's distribution electric and gas system infrastructure following the 2018  
13                  Camp Fire, which devastated the Town of Paradise and surrounding areas  
14                  in Butte County. The fire destroyed over 18,000 structures, including  
15                  13,400 premises and virtually the entirety of electrical and gas infrastructure  
16                  that served the town and surrounding areas. PG&E is committed to our  
17                  customers on completing the rebuild in a safe and sustainable manner.

18                 The scope of this request excludes costs for emergency response  
19                 activities PG&E incurred immediately following the Camp Fire, and covers  
20                 the next phase of work to rebuild the distribution assets to meet the  
21                 long-term needs of the community and provide power to the red-tagged  
22                 customers as they rebuild their homes.

23                 Costs for 2018 – 2022 are subject to recovery on a recorded basis  
24                 through the Catastrophic Event Memorandum Account (CEMA); these  
25                 amounts are included for trending purposes because the activity will become  
26                 General Rate Case (GRC) funded beginning in 2023. PG&E will exclude  
27                 costs disallowed by the Wildfire Order Instituting Rulemaking disallowances  
28                 in accordance with D.20-05-019 when it files for recovery of these costs.

---

<sup>1</sup> Costs for EO are included in the forecast summary for Electric shown in Chapter 2 of this exhibit. Costs for Gas Operations and Customer Care are included in the forecast for those exhibits; however, this chapter provides justification to support all program costs. Electric Operations and Gas Operations refer to distribution assets only (not transmission).

1 Recorded and forecast capital and expense costs shown in this chapter are  
2 gross of the OII costs. Recorded plant balances have been adjusted for the  
3 disallowances.<sup>2</sup>

## 4 **2. Summary of February 25, 2022 Updates**

5 *This section has been added as part of PG&E's February 25, 2022*  
6 *update.*

7 This program update is included in this February 25, 2022 GRC update  
8 pursuant to the Assigned Commissioner's directive to:

9 serve testimony to seek approval for any revisions to the forecasted  
10 expenditures for undergrounding programs that fall within the timeframe  
11 covered by this proceeding, including the extent to which the  
12 expenditure forecasts for its other wildfire mitigation programs should be  
13 revised, along with an explanation of how those forecasted expenditures  
14 are consistent with PG&E's 2022 Wildfire Mitigation Plan."<sup>3</sup>

15 Updates to this chapter include:

- 16 • Section A.3: Explains why PG&E is updating its Community Rebuild  
17 forecast;
- 18 • Section A.4: Updates the overview of recorded and forecast costs to  
19 account for the updated Community Rebuild forecast and errata;
- 20 • Section B: Shows changes to risk spend efficiency calculations due to  
21 changes to cost structure for undergrounding work in the Community  
22 Rebuild program;
- 23 • Section C.2: Updates table of forecast capital costs to show changes in  
24 forecast cost structure for undergrounding work in PG&E's Community  
25 Rebuild program and forecast;
- 26 • Section D: Outlines the changes in PG&E's estimating methods for  
27 undergrounding costs in PG&E's Community Rebuild program and  
28 forecast; and
- 29 • Section F: Presents cost tables showing PG&E's June 30, 2021 forecast  
30 and the updated February 25, 2022 forecast by Major Work Category  
31 (MWC).

---

2 See Exhibit (PG&E-10), Chapter 10, Section D.1.

3 Assigned Commissioner's Scoping Memo and Ruling, filed October 1, 2021, in Application (A.) 21-06-021, pp. 7-8.

1 This supplemental testimony includes the following changes to PG&E's  
2 2023 forecast:

- 3 • Reduction of \$25.9 million in the Community Rebuild Program to reflect  
4 lower unit costs for undergrounding.

5 A summary of the forecast changes, including capital changes through  
6 2026, are provided in Table 23-12 at the end of this chapter. The remainder  
7 of this chapter shows PG&E's updated forecast as compared to 2020  
8 recorded amounts.

### 9 **3. Summary of Request**

10 *This section has been revised to show PG&E's updated Community*  
11 *Rebuild Program capital forecast as of February 25, 2022.*

12 This chapter forecasts expense and capital expenditures for activities in  
13 the Community Rebuild Program across the three lines of business (LOB)  
14 noted above: Electric Operations, Gas Operations, and Customer Care.<sup>4</sup>

15 PG&E requests that the California Public Utilities Commission (CPUC or  
16 Commission) adopt PG&E's 2023 total Company expense forecast of  
17 \$16.7 million for Community Rebuild Program.<sup>5</sup> The 2023 expense forecast  
18 is \$17.9 million less than 2020 recorded adjusted expenses of \$34.6 million.

19 PG&E further requests that the Commission adopt the following updated  
20 total Company capital expenditure forecasts for the Community Rebuild  
21 Program: \$187.3 million for 2021; \$226.4 million for 2022; \$203.3 million for  
22 2023; \$167.5 million for 2024; \$106.8 million for 2025; and, \$27.0 million for  
23 2026.<sup>6</sup> PG&E's updated 2023 capital forecast is \$43.1 million less than  
24 PG&E's original (June 30, 2021) forecast due to a reduction in the forecast  
25 unit cost for undergrounding work. The updated 2023 capital forecast is

---

<sup>4</sup> The Community Rebuild program is funded in Exhibit (PG&E-4), Chapters 4.3 and 23; Exhibit (PG&E-3), Chapters 4 and 13; and Exhibit (PG&E-6), Chapter 7.

<sup>5</sup> Exhibit (PG&E-4), WP 23-13, line 37. Forecast amount includes EO, Gas Operations, and Customer Care.

<sup>6</sup> See Exhibit (PG&E-4), WP 23-13, line 38. Forecast amount includes EO, Gas Operations and Customer Care. PG&E's June 30, 2021 capital expenditure forecast for the Community Rebuild Program was: \$187.3 million for 2021; \$240.8 million for 2022; \$246.4 million for 2023; \$222.9 million for 2024; \$161.6 million for 2025; and, \$27.0 million for 2026.

1 \$45.3 million more than 2020 recorded adjusted capital expenditures of  
2 \$158.0 million.

3 While the total request reflects multiple LOBs at PG&E, the costs for  
4 Major Work Categories (MWC) 95 and IF for the Community Rebuild are  
5 only funded out of this chapter, and are included the total request listed  
6 above. The expense forecast for Exhibit (PG&E-4), Chapter 23 is  
7 \$13.8 million for 2023.<sup>7</sup> The updated capital forecast for Exhibit (PG&E-4),  
8 Chapter 23 is \$87.5 million for 2021; \$124.1 million for 2022; \$116.6 million  
9 for 2023; \$96.1 million for 2024; \$64.4 million for 2025; and \$16.9 million for  
10 2026.<sup>8</sup>

11 Tables 23-1 and 23-2 summarize the 2020 recorded and the expense  
12 and updated capital forecasts for the Community Rebuild Program by  
13 LOB.<sup>9,10</sup>

**TABLE 23-1**  
**EXPENSE RECORDED AND FORECAST BY LOB**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No	Description	2020 Recorded	2021 Forecast	2022 Forecast	2023 Forecast
1	Electric	\$29,194	\$12,071	\$15,138	\$13,781
2	Gas	5,367	1,500	2,859	2,912
3	Total Community Rebuild Program Expense	\$34,562	\$13,571	\$17,997	\$16,693

<sup>7</sup> Exhibit (PG&E-4), WP 23-1, line 1.

<sup>8</sup> See Exhibit (PG&E-4), WP 23-6, line 2. The June 30, 2021 capital forecast for Exhibit (PG&E-4), Chapter 23 was \$87.5 million for 2021; \$133.2 million for 2022, \$142.5 million for 2023, \$129.6 million for 2024, \$97.4 million for 2025, and \$16.9 million for 2026.

<sup>9</sup> Exhibit (PG&E-4), WP 23-13, lines 5 and 20.

<sup>10</sup> Exhibit (PG&E-4), WP 23-13, lines 14, 26, and 35.

**TABLE 23-2**  
**CAPITAL RECORDED AND FORECAST BY LOB**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No	Description	2020	2021	2022	2023	2024	2025	2026
1	Electric	\$112,875	\$129,047	\$177,007	\$170,661	\$140,078	\$91,475	\$16,940
2	Gas	45,097	57,710	48,909	32,153	26,845	15,017	9,727
3	Customer	73	502	515	529	540	328	336
4	Total Community Rebuild Program Capital	\$158,045	\$187,259	\$226,430	\$203,344	\$167,462	\$106,820	\$27,002

1                   Forecasts in this chapter are shown with escalation at the MWC level  
2                   and escalation is included in all expense and capital totals. For more  
3                   information on escalation, please refer to Chapter 2 of this exhibit.<sup>11</sup>

4                   **4. Overview of Recorded and Forecast Costs**

5                   *This section has been revised to show PG&E's updated Community*  
6                   *Rebuild Program capital forecast as of February 25, 2022.*

7                   The testimony of this chapter provides details for all Major Work  
8                   Categories (MWC) across multiples LOBs interdependent and necessary to  
9                   complete the scope of the Community Rebuild Program. Table 23-3 below  
10                  shows expense and capital MWCs and descriptions of the work for the  
11                  Community Rebuild Program across the multiple LOBs.

---

<sup>11</sup> See Exhibit (PG&E-4), Ch. 2, Section E.1.e, p. 2-20, lines 8-31 for more information on escalation.

**TABLE 23-3  
EXPENSE AND CAPITAL MWCs ACROSS THE MULTIPLE LOBs  
COMMUNITY REBUILD PROGRAM**

Line No.	MWCs	Description
1	<u>Expense MWCs</u>	
2	IF	Temporary Services for Pedestal Program
3	IF	Construction Site Cleaning
4	IF	Community Rebuild Program Management Office (PMO)
5	LX	Underground Preventive Maintenance and Equipment Repair
6	LX	Community Rebuild PMO
7	<u>Capital MWCs</u>	
8	95	Electric Underground Main Line Construction
9	95	Electric Overhead Main Line Construction
10	95	Electric Service Connections
11	95	Electric Mobile Home Parks (MHP)
12	95	Remote Grids
13	08	Electric Underground Construction Hardening Program
14	14	Aldyl-A Gas Mainline Construction
15	3M	Service Meters
16	3Q	Gas MHPs
17	3Q	Gas Services

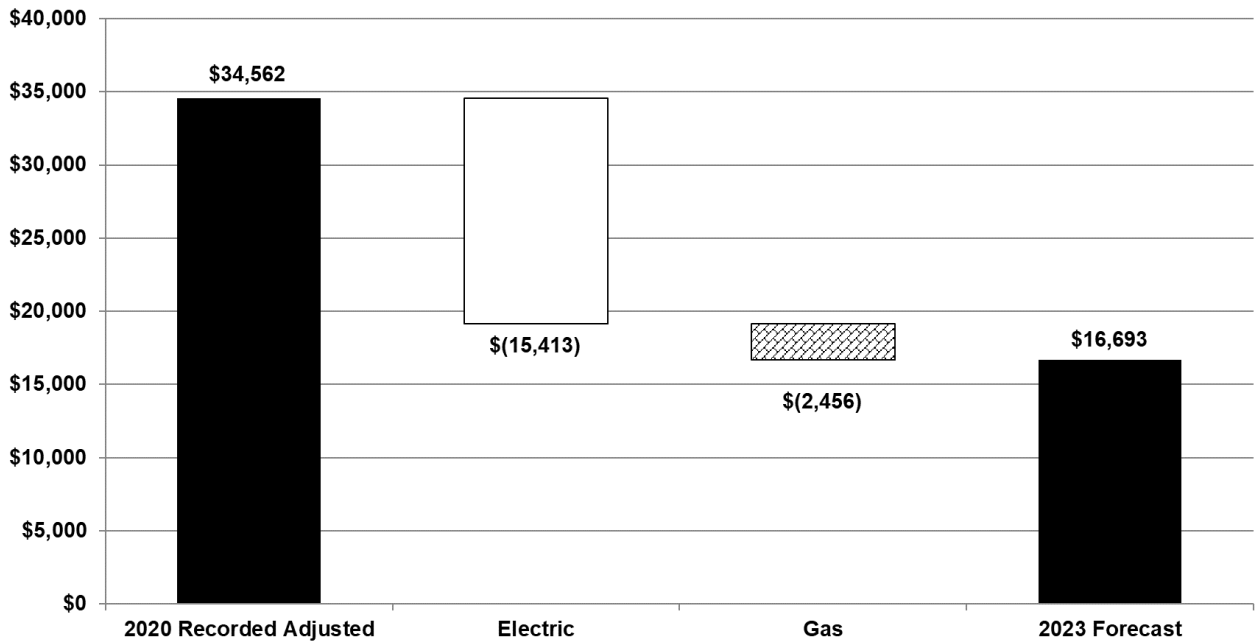
1           **a. Expense**

2                         Figure 23-1 below shows the walk from 2020 recorded adjusted  
3                         expense amounts to the 2023 forecasts for the Community Rebuild  
4                         Program by LOB.<sup>12</sup>

---

<sup>12</sup> Exhibit (PG&E-4), WP 23-13, lines 5 and 20.

**FIGURE 23-1**  
**TOTAL COMPANY EXPENSE WALK BY LOB 2020-2023**



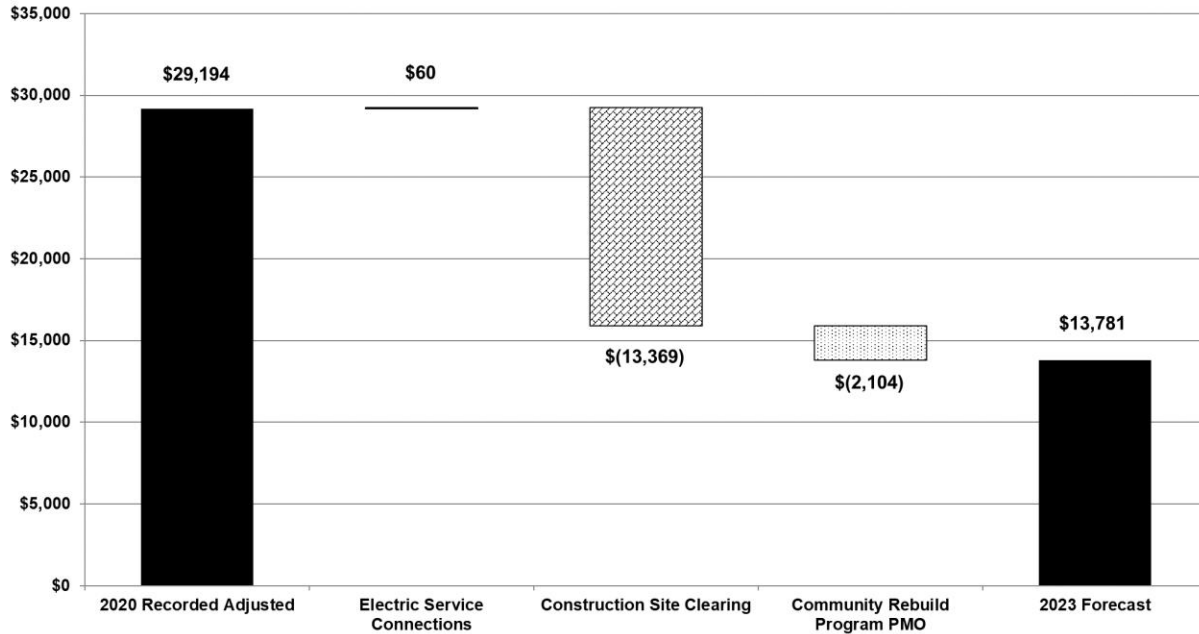
1                   The primary driver behind the forecast decrease from 2020 to 2023  
2 across all LOBs is Electric Operations. See description under Figure  
3 23-2 for more details.

4                   Figure 23-2 below shows the walk from 2020 recorded adjusted  
5 expense amounts to the 2023 forecasts for the Community Rebuild for  
6 the Electric Operations LOB.<sup>13</sup>

---

<sup>13</sup> Exhibit (PG&E-4), WP 23-13, lines 2-4.

**FIGURE 23-2**  
**ELECTRIC OPERATIONS EXPENSE WALK 2020-2023**  
**(THOUSANDS OF NOMINAL DOLLARS)**



1                   As shown in Figure 23-2, the decrease in expenses from 2020 to  
2 2023 is primarily due to a forecast decrease in Construction Site  
3 Clearing spending. In 2020, PG&E incurred significant Construction Site  
4 Clearing costs due to continuing efforts to remove debris related to the  
5 2018 Camp Fire. In 2023, demand for Construction Site Clearing is  
6 expected to be much lower as progress is expected to continue until the  
7 site is cleared of debris.

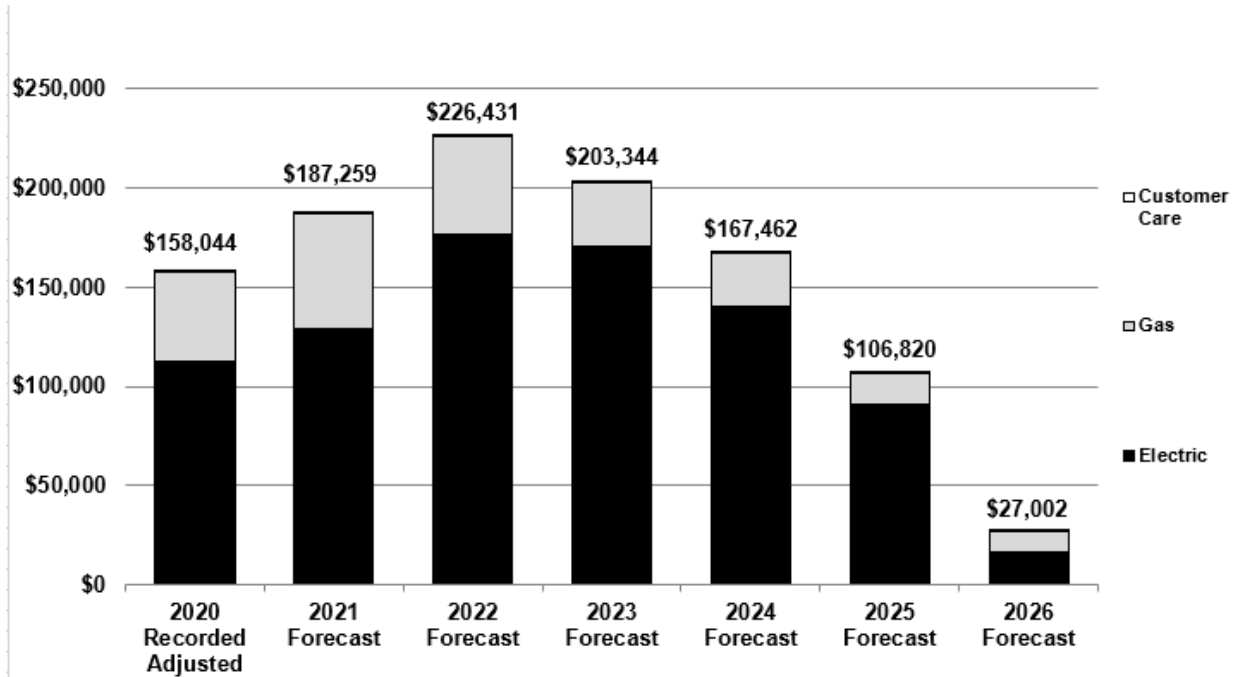
8                   **b. Capital**

9                   Figure 23-3 below shows the 2020 recorded capital expenditures  
10 and the updated 2021 to 2026 forecast capital expenditures for the  
11 Community Rebuild Program by LOB.<sup>14</sup>

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<sup>14</sup> Exhibit (PG&E-4), WP 23-13, lines 14, 26, and 35.

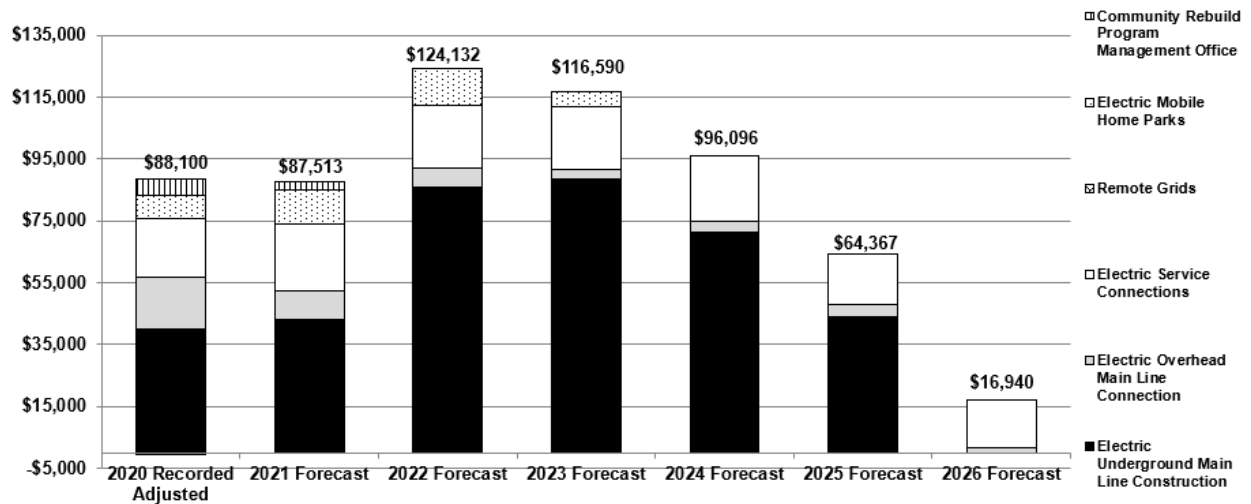
**FIGURE 23-3**  
**CAPITAL RECORDED AND FORECAST COSTS 2020-2026 BY LOB**  
**(THOUSANDS OF NOMINAL DOLLARS)**



1                   As shown in Figure 23-3, the capital costs are driven by the forecast  
2                   for Electric Operations. For Gas Operations, the forecast for  
3                   underground mainline construction of Aldyl-A pipeline replacement  
4                   decreases after 2022.<sup>15</sup> Gas underground construction is a priority for  
5                   the construction plan because it helps avoid providing temporary  
6                   propane to customers who move back into their homes in these areas  
7                   while construction is pending. Due to the small amount of Customer  
8                   Care costs contributing to the operations, these costs are not viewable  
9                   on the scale of this chart.

<sup>15</sup> See Exhibit (PG&E-3), Ch. 4, Section C.2.c. for further details on this work. See Exhibit (PG&E-4), WP 23-14, line 11 for forecast details on the underground mileage for Aldyl-A Gas Mainline Construction per year in the Community Rebuild Program.

**FIGURE 23-4**  
**CAPITAL RECORDED AND FORECAST COSTS 2020-2026**  
**(THOUSANDS OF NOMINAL DOLLARS)**



1 As shown in Figure 23-4, Electric Operations capital costs for the  
 2 Community Rebuild Program are primarily driven by the variability in  
 3 mileage forecasted for electric underground mainline construction  
 4 across the program years.<sup>16</sup> In 2020 and 2021, PG&E was in the  
 5 planning and design phase of the rebuild and securing construction  
 6 contracts as the mileage ramps up for underground construction in 2022  
 7 and 2023. PG&E aims to complete construction by the end of 2025 and  
 8 when forecast costs will be driven primarily by electric service  
 9 connections. The 2026 forecast is driven by the continuation of the  
 10 installation of residential services requested by customers, which at this  
 11 time is expected to continue beyond 2026.

12 PG&E's estimating methodology is discussed further in Section D of  
 13 this chapter.

## 14 5. Support for Request

15 PG&E has an obligation to serve customers and restore assets following  
 16 any disaster once service is requested. Complete restoration of electric  
 17 distribution, gas distribution, and customer meter assets are all necessary to

<sup>16</sup> See Exhibit (PG&E-4), WP 23-10, line 9 for 2020 underground mainline construction recorded mileage and Exhibit (PG&E-4), WP 23-14, line 2 for details of mileage forecasted by year.

1 rebuild the Community damaged by the Camp Fire. The testimony supports  
2 funding to restore assets to the Town of Paradise and parts of Magalia in a  
3 safe and reliable way to serve the long-term needs of the customers, and  
4 safely return to a renewed community.

## 5 **6. Organization of the Remainder of This Chapter**

6 The remainder of this chapter is organized as follows:

- 7 • Section B – Program and Risk Overview;
- 8 • Section C – Activities, Costs, and Forecast Drivers by Workstream;
- 9 • Section D – Estimating Methods;
- 10 • Section E – Compliance with Prior Commission Decisions; and
- 11 • Section F – Cost Tables.

## 12 **B. Program and Risk Overview**

### 13 **1. Program Description**

#### 14 **a. Program Overview**

15 In the 2018 Camp Fire, approximately 199 miles of electric  
16 distribution lines and 34 miles of gas pipeline were destroyed. In  
17 May 2019, PG&E decided to underground all the electric distribution  
18 assets in the Town of Paradise and adjacent parts of Butte County (also  
19 known as the underground footprint) the following reasons:

- 20 • Safety – During the fire many distribution poles fell into the streets  
21 and blocked access to egress routes during the fire. The impacted  
22 area is in a Tier 2 (Elevated) and 3 (Extreme) High Fire Threat  
23 District (HFTD) area, with a very small non-tiered area. The  
24 undergrounding of assets will help reduce wildfire risk from power  
25 lines in the area and help ensure access to safe egress routes if  
26 there is a wildfire (regardless of source of ignition).
- 27 • Joint Trench Opportunities – During the 2018 Camp Fire, 30 miles of  
28 Aldyl-A gas main were destroyed. In addition, 27 miles of gas main  
29 that were not destroyed were planned to be replaced under the  
30 Aldyl-A Pipeline Replacement Safety Program. Even if the Camp  
31 Fire didn't occur, all 57 miles of Aldyl-A gas main would be replaced  
32 at some time in the future and is discussed further in Section C.2.c.  
33 In these areas of Paradise, PG&E is taking advantage of the unique

1 opportunity to underground replacement gas and electric facilities in  
2 a joint trench. Performing joint trench work helps reduce  
3 underground construction costs over the entire program for both the  
4 gas and electric business. In addition, if communication companies  
5 choose to participate in the trench, that will provide additional  
6 opportunities to lower the cost of the underground construction.

- 7 • City Planning – Government leaders and PG&E’s customers in  
8 Paradise and Butte County have expressed the strong desire for  
9 underground utilities in their community to improve the safety egress  
10 paths and improve their town design. During the rebuild efforts, the  
11 Paradise City Council intends to enforce a “dig-once” ordinance.  
12 PG&E is coordinating construction closely with Paradise to complete  
13 construction before the town repaves its primary town arteries.
- 14 • Public Safety Power Shutoff (PSPS) Improvements – In 2020, the  
15 Paradise and Butte County areas experienced five PSPS events  
16 spanning a total of 13 days. As the Community Rebuild project is  
17 executed over the next several years, it will enable undergrounded  
18 areas of Paradise to remain energized during PSPS events.  
19 Scoping for the Community Rebuild is prioritizing PSPS mitigation  
20 while working with the community to align with their rebuild plans.  
21 The Community Rebuild is managed centrally under a core team  
22 that oversees many LOBs within PG&E to complete the scope of  
23 work (electric, gas, sourcing, etc.). The team also regularly  
24 communicates with Federal Emergency Management Agency and  
25 the local county and cities to coordinate construction locations and  
26 timelines.

27 **b. Management Structure**

28 The Community Rebuild program is managed within PG&E’s  
29 Community Rebuild and Resiliency Program (CRRP) Project  
30 Management Organization (PMO) within the Major Projects and  
31 Programs division of EO. PG&E established CRRP oversight in  
32 February 2019 to provide both operational and financial direction, as  
33 well as controls and governance for the various Community Rebuild  
34 workstreams. The Community Rebuild Program involves various

1 coordinated efforts among several matrixed teams within PG&E.  
2 Through the CRRP, PG&E ensures that the right amount of resources is  
3 made available to timely complete Community Rebuild activities,  
4 consistent with the needs of the Paradise community and customers.

5 To that end, CRRP management ensures that the Community  
6 Rebuild Program has dedicated resources for construction  
7 management, operations coordination, underground program  
8 management, services program management, business analysts, and  
9 customer outreach specialists to help manage work scope, schedule,  
10 budget, and customer inquiries regarding the program. Dedicated  
11 resources for the program from other PG&E organizations include:  
12 Safety, Shared Services (Land, Environmental, Permitting, Materials),  
13 Service Planning and Design, Gas and Electric General Construction,  
14 State Infrastructure, Portfolio and Project Management, LOBs,  
15 Estimating/Engineering, Customer Care, Finance, and Planning.

16 Following the 2017 North Bay Fires, PG&E developed a Disaster  
17 Rebuild Annex (Annex to the Company Emergency Response Plan) to  
18 create processes and procedures for restoring significantly interrupted  
19 services caused by disasters, such as wildfires or earthquakes. Each  
20 disaster involves unique circumstances, but one key metric PG&E  
21 closely monitors is its response time for restoring service to customers  
22 from the time they apply for service to when they can move back into  
23 their homes.

## 24 **2. Risk Integration**

25 *The cost table at the end of this section has been revised to reflect*  
26 *PG&E's updated Community Rebuild Program capital forecast as of*  
27 *February 25, 2022.*

28 Chapter 3 of this exhibit describes how EO uses the Enterprise and  
29 Operational Risk Management Program to manage electric system risks.  
30 Table 23-4 below shows the EO risks associated with the forecasts  
31 discussed in this chapter.

**TABLE 23-4  
RISKS DISCUSSED IN THIS CHAPTER**

Line No.	Risk Name	Risk ID	Type of Risk	Maintenance Activity Type (MAT)
1	Wildfire	WLDFR	Risk Assessment and Mitigation Phase (RAMP)	95F

1           **a. RAMP Risk – Wildfire**

2                   **1) Risk Overview**

3                               Wildfire Risk is defined as the PG&E assets or activities that  
4                               may initiate a fire that is not easily contained and endangers the  
5                               public, private property, or sensitive lands or environment. Wildfire  
6                               was one of PG&E’s 2020 RAMP risks.<sup>17</sup>

7                               In Chapter 3, PG&E describes how management of the wildfire  
8                               risk has changed since the filing of the 2020 RAMP Report; provides  
9                               updated Risk Spend Efficiency (RSE) scores; and lists each  
10                              mitigation/control and indicates if they have changed since the 2020  
11                              RAMP Report filing. In this chapter, PG&E provides additional  
12                              information about the mitigations/controls and the work needed to  
13                              implement them.

14                   **2) GRC Risk Mitigations and Controls**

15                              As shown in the table below, PG&E is forecasting one mitigation  
16                              associated with work discussed in this chapter. The mitigation was  
17                              determined to reduce the frequency or consequence of risk of  
18                              wildfire. A brief description of the mitigation is provided in the  
19                              table below.

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<sup>17</sup> PG&E’s 2020 RAMP Report, A.20-06-012 (June 30, 2020), Ch. 10.

**TABLE 23-5  
WILDFIRE  
FORECAST MITIGATIONS**

Line No.	Mitigation Number	Mitigation Name	Description	Risk Drivers Addressed	MAT Code
1	WLDFR-M014	Butte County Rebuild	To rebuild PG&E's electric system infrastructure following the 2018 Camp Fire.	All Drivers	95F

1                                    This mitigation undergrounds assets to help reduce wildfire risk  
2                                    from power lines in the area and help ensure access to safe egress  
3                                    routes if there is a wildfire. This mitigation consists of Electric  
4                                    Underground Mainline Construction tracked in MAT 95F and  
5                                    described in in Section C.2.a.<sup>18</sup>

6                                    The underground system hardening work described in  
7                                    Section C.2.b and tracked in MAT 08W is accounted for in the  
8                                    System Hardening chapter, (Chapter 4.3). Work described for  
9                                    Aldyl-A Gas Underground Construction in Section C.2.c is tracked in  
10                                    MAT 14D and is accounted for in Exhibit (PG&E-3), Chapter 4.

### 11                                    **3) Changes to Mitigations**

12                                    This mitigation was not included in PG&E's 2020 RAMP Report.  
13                                    WLDFR-M014 is a new mitigation in the GRC.

### 14                                    **4) Cost Tables**

15                                    The table below shows the forecast costs for the mitigation  
16                                    associated with work in this chapter.<sup>19</sup>

17                                    As part of the February 25, 2022 GRC update PG&E revised its  
18                                    forecast costs for this mitigation. The revised costs are shown in  
19                                    Table 23-6 below.

20                                    Tables showing the GRC forecast costs compared to the costs  
21                                    estimated in the 2020 RAMP Report are provided in workpapers.<sup>20</sup>

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**18** The mitigation does not include Electric MHP and Electric Services Connections that are also tracked in MAT 95F.

**19** See Exhibit (PG&E-4), WP 3-5 line 32 (WLDFR mitigations, capital).

**20** See Exhibit (PG&E-4), WP 3-21.

TABLE 23-6  
WILDFIRE  
MITIGATION FORECAST COSTS 2020-2026 – CAPITAL  
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation No. (2023 GRC)	Mitigation Name (2023 GRC)	MAT	2020 Recorded Adjusted	February 25, 2022 Updated Forecast					RSE Updated 2/25/22	
					2021 Forecast	2022 Forecast	2023 Forecast	2024 Forecast	2025 Forecast		2026 Forecast
1	WLDLFR-M014	Butte County Rebuild	95F	\$0	\$0	\$88,450	\$71,511	\$44,087	\$0	\$204,048	1.0
2		Total		\$0	\$0	\$88,450	\$71,511	\$44,087	\$0	\$204,048	

## 1 C. Activities, Costs, and Forecast Drivers by Workstream

2 *The capital cost tables at the end of this section have been revised to*  
 3 *reflect PG&E's updated Community Rebuild Program capital forecast as of*  
 4 *February 25, 2022.*

5 This section describes work being performed in workstreams related to  
 6 general construction, restoration, replacement, and hardening work completed  
 7 by PG&E on its electric and gas assets. Some of costs requested in this chapter  
 8 are included in the cost forecasts presented in other chapters of PG&E's  
 9 testimony. Work in these workstreams is further delineated by major activity  
 10 type, or MAT code, under which activity costs are recorded. Table 23-7 lists the  
 11 MAT codes associated with the Community Rebuild workstreams.

**TABLE 23-7  
 WORKSTREAMS AND MAT FOR COMMUNITY REBUILD PROGRAM SCOPE**

Line No.	Workstreams	MAT Code	Description
1	<u>Expense</u>		
2	W1	IFF	Temporary Services for Pedestal Program
3	W2	IFF	Construction Site Clearing
4	W3	IFF	Community Rebuild PMO
5	W4	LXA	Community Rebuild PMO
6	<u>Capital</u>		
7	W5	95F	Electric Underground Main Line Construction
8	W6	08W	Electric Underground Main Line Construction Hardening Program
9	W7	14D	Aldyl-A Gas Mainline Construction
10	W8	95F	Electric Overhead Main Line Construction
11	W9	95F	Electric Service Connections
12	W10	3QA	Gas Services
13	W11	03M	Service Meters
14	W12	95F	Electric MHPs
15	W13	3QA	Gas MHPs
16	W14	95F	Remote Grids

### 12 1. Expense Workstreams

13 Expense forecasts are associated with the work activities needed to  
 14 provide electric and gas connections and service to the customers in the

1 Community Rebuild Program.<sup>21</sup> For the expense workstreams discussed  
2 below, see Section D for further details on the cost drivers and PG&E's  
3 Project and Program Authorization and Approval Procedure utilized for  
4 calculating the Expected Case Forecast.

5 The table in section C.1.d. summarizes the forecast for each expense  
6 workstream.

7 **a. W1 – Temporary Services for Pedestal Program (MAT IFF)**

8 This work category concerns PG&E's activities for providing  
9 temporary electrical service. PG&E filed Advice Letter (AL) 5744-E on  
10 January 24, 2020 and received CPUC approval on April 17, 2020 to  
11 install underground temporary electric service pedestals to customers  
12 that apply for temporary service within the underground footprint of the  
13 Community Rebuild. This program results in costs savings for both  
14 PG&E and the customer due to the nature of the program construction  
15 timeline. Once the underground construction is completed in the  
16 residential underground footprint, the program will conclude. The  
17 expenses for this program include the cost of the pedestal material and  
18 the labor to remove the pedestal at the time the permanent service is  
19 installed. The capital costs include the labor and material to install the  
20 permanent splice box to connect to the temporary pedestal.

21 **b. W2 – Construction Site Clearing (MAT IFF)**

22 This work category is associated with Site Clearing activities to  
23 maintain a safe construction site for crews working on the Community  
24 Rebuild. Many dead trees were left over from the 2018 Camp Fire in  
25 construction zones where PG&E's Community Rebuild activities occur.  
26 PG&E will remove trees that pose a safety risk to construction crews.  
27 Per PG&E's accounting guidelines, removal of dead trees adjacent to  
28 infrastructure is expense work.

29 **c. W3 and W4 – Community Rebuild PMO (MATs IFF and LXA)**

30 As described above, the Community Rebuild PMO provides  
31 oversight on the matrixed resources supporting the program and

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<sup>21</sup> PG&E has an obligation to serve customer driven work (PG&E Electric Rule No. 2, Rule No. 15, and Rule No. 16).

1 ensures that the project scope, schedule, and financials are governed  
2 appropriately.

### 3 **d. Expense Workstream Summary**

4 Table 23 -8 below presents 2020 recorded and 2021 through 2023  
5 forecasted expenses for the Community Rebuild Program, by LOB and  
6 Workstream.

**TABLE 23-8**  
**EXPENSE RECORDED AND FORECAST BY LOB AND WORKSTREAM**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Workstream	2018	2019	2020	2021	2022	2023
1	<u>Electric</u>						
2	W1/W9 - Electric Service Connections	\$(44)	–	\$156	\$360	\$205	\$215
3	W2 – Construction Site Clearing	123,521	231,744	23,840	8,751	11,986	10,471
4	W3 – Community Rebuild PMO	–	1,549	5,198	2,960	2,947	3,095
5	<u>Gas</u>						
6	W7 – Gas Main Construction	–	5,325	(4,016)	–	–	–
7	W10 – Gas Services	–	71	8,454	–	–	–
8	W14 – Community Rebuild PMO	–	1,355	930	1,500	2,859	2,912
9	Total	\$123,477	\$240,045	\$34,562	\$13,571	\$17,997	\$16,693

## 7 **2. Capital Workstreams**

8 The capital workstreams describe the work that enables the construction  
9 of permanent rebuild of electric and gas distribution assets to restore service  
10 to customers in the Community Rebuild Program.<sup>22</sup> For the capital  
11 workstreams discussed below, see Section D for the capital expenditure  
12 estimating method.

13 The table in section C.2.j. summarizes the forecast for each capital  
14 workstream.

### 15 **a. W5 – Electric Underground Main-Line Construction (MAT 95F,** 16 **WLDFR-M014)**

17 This work category involves activities performed for restoring electric  
18 distribution assets underground. The capital expenditures recorded in  
19 MAT 95F are activities associated with restoring underground mainline

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<sup>22</sup> PG&E has an obligation to serve customer driven work (PG&E Electric Rule No. 2, Rule No. 15, and Rule No. 16).

1 where the service was underground prior to the fire and that PG&E has  
 2 an obligation to restore, or where the underground mainline work is  
 3 located in non-HFTD areas.<sup>23</sup> For these reasons these underground  
 4 assets are not recorded to MAT 08W although they are built to the same  
 5 standards as the wildfire mitigation work in the system hardening  
 6 program and provide risk reduction. This electric underground main-line  
 7 construction work recorded in 95F is Wildfire Mitigation (WLDFR-M014),  
 8 so will be included in the WMBA in 2023.<sup>24</sup>

9 **b. W6 – Electric Underground Main-Line Construction Hardening**  
 10 **Program (MAT 08W)**

11 This work category covers activities for underground construction of  
 12 electric distribution assets in Tier 2 or Tier 3 HFTD areas. Assets in this  
 13 category for the Community Rebuild were previously overhead and are  
 14 being transitioned to underground. PG&E plans to underground 39.2  
 15 miles that were previously overhead as part of the Community Rebuild  
 16 under the MAT 08W category of work. PG&E seeks approval for costs  
 17 related to the underground construction of electric distribution assets  
 18 that is part of the Community Rebuild Program in Chapter 4.3 of this  
 19 Exhibit. This work is part of the broader System Hardening Program in  
 20 MAT 08W and, as such, is included in the overall System Hardening  
 21 Program forecast.<sup>25</sup>

22 **c. W7 – Aldyl-A Gas Underground Construction (MAT 14D)**

23 The work category involves PG&E's proactive replacement of  
 24 Aldyl-A assets as part of the Aldyl-A Gas Pipeline Replacement  
 25 Program.<sup>26</sup> To share construction costs in the areas where these  
 26 replacements are occurring, PG&E is performing joint trenching with the

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23 For a description of the underground construction, including justification and benefits, please see workpaper Exhibit (PG&E-4), Ch. 23 – Project Summary – Community Rebuild Program.

24 See discussion of the WMBA in Exhibit (PG&E-4), Chapter 4, Section D.1. Also see Exhibit (PG&E-4), WP 4-35.

25 This work is included in mitigation WLDFR-M002 that is described in Exhibit (PG&E-4), Ch. 4.3, Section C.1.a and C.1.b.

26 This program work is described further in Exhibit (PG&E-3), Ch. 4, Section B.2.c, starting at p. 4-27; also see, p. 4-30, line 23 to p. 4-31, line 9.

1 electric distribution assets that are being restored. All the joint trenching  
2 of electric and gas assets includes the replacement of Aldyl-A pipe.  
3 Some of Aldyl-A pipe is being replaced because it was destroyed by the  
4 Camp Fire and subsequently decommissioned. In other cases, the pipe  
5 is still in working condition, but is being replaced as part of the workplan  
6 for the pre-existing Aldyl-A Program. The higher leak rate for plastic  
7 pipe installed prior to 1985 correlates with known issues of Aldyl-A  
8 plastic pipe installed prior to 1985 (i.e., susceptibility of pipe to slow  
9 crack growth when exposed to external stress), which is being  
10 addressed through the Plastic Pipe Replacement Program in 14D.<sup>27</sup>

11 **d. W8 – Electric Overhead Main-Line Construction (MAT 95F)**

12 This work category concerns distribution overhead hardening work  
13 in areas outside of the footprint where PG&E plans to underground  
14 distribution assets. Many customers in remote locations were served by  
15 overhead distribution assets that were destroyed by the Camp Fire. In  
16 these areas, PG&E will replace the assets with overhead distribution  
17 assets that meet current hardened standards. PG&E has estimated and  
18 designed all of these locations, but only completes the construction  
19 when a customer applies for service and there is an existing need for  
20 the line to be restored.

21 **e. W9 – Electric Services (MAT 95F)**

22 This work category concerns the restoration of electric service to  
23 customers. 13,400 customers lost their homes in the 2018 Camp Fire.  
24 As customers rebuild their homes, PG&E restores their electric service.  
25 All the services within the planned underground footprint in Paradise  
26 and surrounding areas are constructed underground, sharing a trench  
27 with the gas service if the customer also received gas from PG&E. In  
28 the areas outside the underground footprint, PG&E restores the service  
29 as an overhead service. If a customer did not have electric service prior  
30 to the 2018 Camp Fire, they must apply for service under the Rule 16  
31 Tariff and pay for the service.

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<sup>27</sup> Exhibit (PG&E-3), Ch. 4, WP 4-40, Project Summary - Plastic Pipe Replacement Program.

1           **f. W10 – Gas Services (MAT 3QA)**

2                     This work category concerns the restoration of gas service to  
3 customers. In locations where customers had gas service prior to the  
4 Camp Fire, PG&E will restore the gas service when the customers apply  
5 for service after they rebuild their homes. As noted above, PG&E will  
6 joint trench electric and gas utilities when possible to save on  
7 construction costs and leverage limited space for trenching on the  
8 customer property. If a customer did not have gas service prior to the  
9 2018 Camp Fire, they must apply under the current Rule 16 Tariff and  
10 pay for the service.

11           **g. W11 – Service Meters (MAT 03M)**

12                     This category concerns the meters installed as part of the  
13 establishment of permanent service.<sup>28</sup>

14           **h. W12 and W13 – Electric and Gas Mobile Home Parks (MATs 95F  
15 and 3QA)**

16                     The scope of work for this team is to rebuild the electric and gas  
17 distribution system at Mobile Home Parks (MHPs) in Paradise and  
18 surrounding areas. In contrast to the MHP Utility Conversion Program  
19 (Chapter 13), the scope of work excludes the beyond the meter  
20 connection from the electric pedestal or gas meter to the mobile home,  
21 but includes additional service connections to other non-mobile home  
22 infrastructure within the MHP, such as apartment buildings and multiple  
23 common areas. The reason why the scope of work excludes the  
24 beyond the meter connection from the electric pedestal or gas meter to  
25 the mobile home is that the MHPs are currently vacant, and there are no  
26 mobile homes to receive the connection.

27           **i. W14 – Remote Grids**

28                     In a few locations for the Community Rebuild Program, PG&E  
29 analyzed potential opportunities to leverage the Remote Grid Program  
30 to serve customers. These locations were pockets of isolated small  
31 customer loads served via long electric distribution feeders in HFTD

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<sup>28</sup> See Exhibit (PG&E-6), Chapter 7 Metering Services and Engineering, WP 7-10 and WP 7-14.

1 areas. To date, Remote Grid did not emerge as the best rebuild  
2 alternative for the sites assessed as other more cost effective rebuild  
3 alternatives were identified. The CRRP team regularly evaluates  
4 potential opportunities with PG&E's Remote Grid Program and may be  
5 deployed as a rebuild option if it is determined to be the best alternative  
6 for specific remote locations going forward. Please see Exhibit  
7 (PG&E-4), Chapter 4.3 for more information on the Remote Grid  
8 Program.

9 **j. Capital Workstream Summary**

10 Table 23-9 below presents the 2019 and 2020 recorded costs and  
11 2021 through 2026 forecasted capital costs for the Community Rebuild  
12 Program, by LOB and Workstream. As part of its February 25, 2022  
13 GRC update submittal, PG&E has revised Table 23-9 to show PG&E's  
14 revised forecast for undergrounding work based on the new  
15 undergrounding unit cost discussed in PG&E's update to Chapter 4.3.

**TABLE 23-9  
CAPITAL RECORDED AND FORECAST EXPENDITURES BY LOB AND WORKSTREAM  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	Workstream	2019	2020	2021	2022	2023	2024	2025	2026
1	<u>Electric</u>								
2	W5- Electric Underground Mainline Construction	\$21,521	\$40,006	\$42,914	\$85,875	\$88,450	\$71,511	\$44,087	–
3	W6-Electric Underground Construction Hardening Program	16,818	24,774	41,534	52,875	54,072	43,982	27,107	–
4	W8-Electric Overhead Main Line Construction	13,441	16,958	9,300	6,256	3,055	3,279	3,642	\$1,672
5	W1/W9-Electric Service Connections	11,590	18,535	21,730	20,322	20,354	21,306	16,639	15,268
6	W12/W13- Electric Mobile Home Parks	1,619	7,544	11,069	11,679	4,731	–	–	–
7	W3-Community Rebuild Program Management Office	–	5,283	2,500	–	–	–	–	–
8	W14-Remote Grids	225	(225)	–	–	–	–	–	–
9	<u>Gas</u>								
10	W7-Aldyl-A Gas Mainline Construction	14,529	27,284	25,600	24,722	14,344	10,977	4,502	–
11	W7-Gas Main Construction	–	2,949	–	–	–	–	–	–
12	W10-Gas Services	756	8,883	27,294	14,773	15,043	15,868	10,515	9,727
13	W13-Gas Mobile Home Parks	1,150	5,981	4,817	9,414	2,767	–	–	–
14	<u>Customer Care</u>								
	W11-Nov 2018 Camp Fire-Electric Meters-CEMA	26	6	248	254	–	–	–	–
15	W11-Nov 2018 Camp Fire-Gas Meters-CEMA	47	37	254	261	–	–	–	–
16	W11-Nov 2018 Camp Fire-Gas Modules-CEMA	–	30	–	–	–	–	–	–
17	W11-Butte Wildfire Rebuild - Electric Meters	–	–	–	–	261	267	162	166
18	W11-Butte Wildfire Rebuild-Gas Mtrs/Modules	–	–	–	–	268	273	166	170
19		–	–	–	–	268	273	166	170
20	Total Company Capital	\$81,723	\$158,045	\$187,259	\$226,431	\$203,345	\$167,463	\$106,820	\$27,002

## 1 D. Estimating Methods

2 *This section has been updated to reflect PG&E's revised estimating*  
3 *methodology for the capital forecast for undergrounding work in the*  
4 *Community Rebuild Program as of February 25, 2022.*

5 PG&E describes here the methods used to develop the Community Rebuild  
6 expense and capital forecasts. See the workpapers for this chapter for more  
7 details on the forecast and the workstreams.

### 8 1. Expense

9 Community Rebuild expense costs are based on costs for material and  
10 labor costs.

11 The Temporary Service for Pedestal Program workstream W1 forecast  
12 is based on the cost of the pedestal material and the labor to remove the  
13 pedestal at the time the permanent service is installed. There is also a  
14 capital component based on the labor and material to install the permanent  
15 splice box to connect to the temporary pedestal.

16 The Construction Site Clearing workstream W2 forecast is based on unit  
17 cost per foot for construction Site Clearing during PG&E's initial emergency  
18 response effort to the 2018 Camp Fire, program progress in 2019 and 2020,  
19 and on factors specific to the Community Rebuild program.

20 The Community Rebuild PMO workstreams W3 and W4 consists  
21 primarily of Community Rebuild Program's PMO labor, or headcount needed  
22 for program oversight and support. 95 percent of headcount for the PMO is  
23 charged directly to major capital project costs for the underground  
24 construction on the Community Rebuild. The other 5 percent of the  
25 headcount for the Community Rebuild Program PMO is reflected in the  
26 expense forecast. This expense forecast is further split 50/50 between gas  
27 and electric to share support resources since both commodities are built in  
28 the program.

### 29 2. Capital

30 PG&E used both a unit cost and project cost estimating methodologies  
31 to forecast the costs for the work described herein.

1           **Electric Underground and Overhead Main Line Construction, and**  
2           **Electric and Gas Services**

3           To develop an initial forecast for workstreams W8, W9, and W10 PG&E  
4           benchmarked the rebuild costs associated with the Coffey Park rebuild after  
5           the 2017 Northern California Wildfire Season due to similar construction  
6           factors such as joint trench construction, urban environment, and soil  
7           conditions. PG&E then adjusted the cost from the Coffey Park rebuild to  
8           account for factors specific to the Camp Fire footprint. The primary factors  
9           driving the adjustments were joint utility participation<sup>29</sup> and resource  
10          availability. Workstreams W5, W6 and W8 forecasts were based on a  
11          cost/foot, and workstreams W9 and W10 were based on a cost per premise  
12          (typically property or account) from the Coffey Park rebuild. The units for  
13          underground mainline mileage were based on the miles of distribution that  
14          existed prior to the Camp Fire.

15          In its June 30, 2021 testimony, PG&E also used the method described  
16          above to estimate the unit costs for workstreams W5 and W6 – work to  
17          install underground distribution lines as part of Community Rebuild Program.  
18          PG&E's February 25, 2022 update to Chapter 4.3 of its testimony discusses  
19          significant changes to PG&E's proposed undergrounding plan for  
20          2022-2026. The updated plan includes significant revisions to the forecast  
21          unit cost for undergrounding work to reflect efficiencies and economies of  
22          scale that PG&E expects to achieve through the new plan. PG&E is also  
23          applying those updated unit cost assumptions to the undergrounding  
24          workstreams in the Community Rebuild Program. For further information  
25          about the revised unit cost assumptions for undergrounding, see PG&E's  
26          February 25, 2022 update to Chapter 4.3.

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<sup>29</sup> Communication companies have the option to participate in the underground mainline trench and services. If they choose to do so, they each pay a fee based on the Form B Agreement, which helps drive down the costs of the construction. To date, the participation from communication companies had been less than the participation from the Coffey Park project.

1        **Aldyl-A Gas Underground Construction, Service Meters, and Electric**  
2        **and Gas Mobile Home Parks**

3            For workstream W7, PG&E used the replacement unit cost for Aldyl-A  
4        Gas Mainline Construction described in Exhibit (PG&E-3) Chapter 4,  
5        WP 4-18.

6            For workstream W11, PG&E used the unit cost method for meters as  
7        described in the Metering Services and Engineering Chapter Exhibit  
8        (PG&E-6), WP 7-10 and 7-14. Annual units for residential and commercial  
9        services for the Community Rebuild Program are based on current demand  
10       trends and rebuild rates from other disasters, specifically including the 2017  
11       and 2018 Northern California Wildfires.

12           For workstreams W12 and W13, PG&E evaluated the cost per space  
13       based on historical averages mobile home spaces costs for PG&E for years  
14       2016 – 2018 and adjustments based on factors specific to the Camp Fire  
15       footprint drivers, as described above. Units for MHPs are forecasted based  
16       on current customer demand to rebuild MHPs; the majority of MHPs in the  
17       Community Rebuild scope have applied for participation.

18           There is no forecast for Remote Grid workstream W14 and therefore no  
19       estimating method.

20           Following the initial capital forecast development described above,  
21       workstream costs were adjusted in 2020 based on the actual costs incurred  
22       on the Community Rebuild project in 2019 and 2020.

23        **E. Compliance With Prior Commission Decisions**

24           **1. Compliance With Section 5.2 of the 2020 GRC Settlement Agreement**  
25           **(“Deferred Work Principles”)**

26            The 2020 GRC Settlement Agreement requires PG&E to include  
27       testimony in this GRC on deferred work if the following criteria are met:

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

1 For work covered in this chapter, Check 1 in (a) was deemed to not  
2 apply, as this work was not forecasted in the 2020 GRC. This analysis is  
3 presented in the workpapers supporting Chapter 2 of this exhibit.<sup>30</sup>

## 4 **2. Compliance With Other Commission Decisions**

5 As outlined in PG&E's 2021 Wildfire Mitigation Plan, the Community  
6 Rebuild Program completed 21.3 miles of underground construction within  
7 the Camp Fire boundaries, exceeding the 20-mile target for 2020.<sup>31</sup>  
8 PG&E's target for 2021 is 23 miles.

9 Cost recovery for Community Rebuild Expenditures for 2019-2020  
10 excludes costs disallowed by the Wildfire Order Instituting Rulemaking  
11 disallowances in accordance with Decision 20-05-019.

12 System hardening costs recorded to MWC 08W through December 31,  
13 2020 are included in the 2020 Wildfire Mitigation Catastrophic Events  
14 Application (A.20-09-019).

15 Recovery of program costs not forecast in this GRC may be included in  
16 future proceedings. AL 5744-E was approved by the CPUC for PG&E to  
17 pilot a program and provide temporary service pedestals to customers, as  
18 described in W7. AL 6120-E was subsequently approved to expand the  
19 pedestal program beyond the pilot phase.

20 PG&E is seeking property insurance claim reimbursements related to  
21 the Camp Fire. At this time, reimbursement amounts and timing are not  
22 known; therefore, the reimbursement amounts are not reflected in this GRC  
23 forecast. Once any reimbursement amounts and timing are known from  
24 insurers, PG&E will either update this GRC or utilize another regulatory  
25 process to make revenue adjustments to reimburse customers.

## 26 **F. Cost Tables**

27 *This section has been modified to show PG&E's June 30, 2021 forecast and*  
28 *PG&E's updated forecast as of February 25, 2022.*

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<sup>30</sup> See Exhibit (PG&E-4), WP 2-15.

<sup>31</sup> See R.18-10-007, PG&E's 2021 WMP Report (Feb. 5, 2021) Section 7.3.3.17.6, Butte County Rebuild Program, for further details.

1           The Electric Operations expense and capital forecasts for Community  
2 Rebuild Program activities are summarized in the following tables.<sup>32</sup>  
3       • Table 23-10 lists expense MWCs showing 2016 through 2020 recorded  
4 adjusted expenses and 2021 through 2023 forecast expenses;<sup>33</sup>  
5       • Tables 23-11 to 23-13 lists capital MWCs showing 2016 through 2020  
6 recorded capital adjusted expenditures and 2021 through 2026 forecast  
7 expenditures; and<sup>34</sup>  
8       • Table 23-14 lists the total forecasted units for four years through 2026, by  
9 Workstream, across all LOBs funding Community Rebuild.<sup>35</sup>

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**32** Amounts subject to recovery under the CEMA are shown for trending purposes as they will become GRC funded beginning in 2023.

**33** Exhibit (PG&E-4), WP 23-1, line 2.

**34** Exhibit (PG&E-4), WP 23-6, line 2.

**35** Exhibit (PG&E-4), WP 23-14, lines 1-17.

**TABLE 23-10  
ELECTRIC OPERATIONS EXPENSE  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast			Workpaper Reference
			2016	2017	2018	2019	2020	2021	2022	2023	
1	IF	Community Rebuild Expense	-	-	\$123,477	\$233,292	\$29,194	\$12,071	\$15,138	\$13,781	WP 23-1, line 1
2		Total	-	-	\$123,477	\$233,292	\$29,194	\$12,071	\$15,138	\$13,781	

**TABLE 23-11  
JUNE 30, 2021 GRC FORECAST  
ELECTRIC OPERATIONS CAPITAL  
(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast			Workpaper Reference		
			2016	2017	2018	2019	2020	2021	2022	2023		2024	2025
1	95	Community Rebuild Capital	-	-	\$48,397	\$88,100	\$87,513	\$133,169	\$142,480	\$129,570	\$97,444	\$16,940	
2		Total	-	-	\$48,397	\$88,100	\$87,513	\$133,169	\$142,480	\$129,570	\$97,444	\$16,940	

**TABLE 23-12**  
**DIFFERENCE: FEBRUARY 25, 2022 FORECAST – JUNE 30, 2021 FORECAST**  
**ELECTRIC OPERATIONS CAPITAL**  
**(THOUSANDS OF NOMINAL DOLLARS)**

Line No.	MWC	Description	Recorded Adjusted					Forecast					Workpaper Reference
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	
1	95	Community Rebuild Capital	\$0	\$0	\$0	\$0	\$0	(9,037)	(25,891)	(33,474)	(33,076)	\$0	
2		Total	\$0	\$0	\$0	\$0	(9,037)	(25,891)	(33,474)	(33,076)	\$0		

Line No.	MWC	Description	Recorded Adjusted					Forecast					Workpaper Reference	
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		2026
1	95	Community Rebuild Capital	-	-	-	\$48,397	\$88,100	\$87,513	\$124,132	\$116,590	\$96,096	\$64,367	\$16,940	WP 23-6, line 1
2		Total	-	-	-	\$48,397	\$88,100	\$87,513	\$124,132	\$116,590	\$96,096	\$64,367	\$16,940	

**TABLE 23-14  
TOTAL FORECASTED UNITS 2023-2026 BY WORKSTREAM FOR ALL LOBS FUNDING COMMUNITY REBUILD**

Line No.	Workstream	Workstream	MAT Code	Capital vs. Expense	2023	2023	2023-2026
					GRC Exhibit	GRC Chapter	Forecasted Units
1							
2	W5	Electric Underground Mainline Construction	95F	Capital	4	23	63.9 miles
3	W6	Electric Underground Construction Hardening Program	08W	Capital	4	4.3	39.2 miles
4	W8	Electric Overhead Main Line Construction	95F	Capital	4	23	7 miles
5	W1/W9	Electric Service Connections	95F/IFF	Capital and Expense	4	23	4,717 underground services
6	W12	Electric MHPs	95F	Capital	4	23	672 overhead services, 1,065 temporary power pedestals
7	W2	Construction Site Clearing	IFF	Expense	4	23	115 spaces
8	W3	Community Rebuild PMO	IFF	Expense	4	23	92 miles (Underground and overhead)
9	W14	Remote Grids	95F	Capital	4	23	20 Full-Time Equivalents (FTE)
10	<u>Gas</u>						
11	W7	Aldyl-A Gas Mainline Construction	14D	Capital	3	4	9.6 miles
12	W7	Gas Main Construction	3QA/LXA	Capital and Expense	3	4	
13	W10	Gas Services	3QA/50B/FIM/LX	Capital and Expense	3	13	4,717 gas services
14	W13	Gas MHPs	3QA/50A	Capital	3	13	84 spaces
15	W4	Community Rebuild PMO	LXA	Expense	3	13	20 FTE
16							
17	W11	Nov 2018 Camp Fire-Electric Meters-CEMA	3M	Capital	6	7	4,717 meters
18	W11	Nov 2018 Camp Fire-Gas Meters-CEMA	3M	Capital	6	7	4,717 meters
19	W11	Nov 2018 Camp Fire-Gas Modules-CEMA	3M	Capital	6	7	4,717 meters
20	W11	Butte Wildfire Rebuild-Electric Meters	25	Capital	6	7	4,717 meters
21	W11	Butte Wildfire Rebuild-Gas Mtrs/Modules	74	Capital	6	7	4,717 meters

**PACIFIC GAS AND ELECTRIC COMPANY  
2023 GENERAL RATE CASE**

Testimony:  Workpapers:  SOQ:   
Exhibit Number: 4 Chapter Number: 23  
Chapter Title: Community Rebuild Program  
Witness Name: Marcela Fox

Page No.	Line No.	Item	As Filed	As Corrected
<b>Errata as of November 5, 2021</b>				
23-27 Table 23-10	Header	Header Corrections	Recorded Adjusted: 2016-2019 Forecast: 2020-2023	Recorded Adjusted: 2016-2020 Forecast: 2021-2023
23-27 Table 23-10	1	MWC Description change for clarification	“E Dist Major Emergency”	“Community Rebuild Expense”
23-27 Table 23-11	1	MWC Description change for clarification	“E Dist Major Emergency”	“Community Rebuild Capital”

<b>Page No.</b>	<b>Line No.</b>	<b>Item</b>	<b>As Filed</b>	<b>As Corrected</b>
<b>Errata as of February 25, 2022</b>				
23-21	6	Section Title	Worksteam	Workstream

**PACIFIC GAS AND ELECTRIC COMPANY**  
**APPENDIX A**  
**CONFIDENTIAL COSTS FOR THE ELKHORN BATTERY**  
**ENERGY STORAGE SYSTEM**  
**(PUBLIC)**

Pacific Gas and Electric Company  
 Exhibit (PG&E-4), Chapter 21, Integrated Grid Platform and Grid Modernization Plan  
 Confidential Costs for the Elkhorn Battery Energy Storage System  
 (Thousands of Nominal Dollars)

Line No.	Project Component	MAT	Recorded Adjusted					Forecast					Total			
			2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		2026		
1	<b>Capital</b>															
2	Elkhorn BESS (Capital)	3RC				\$ 15,460	\$ 86,080									
3	Elkhorn BESS (Gen-Tie)	82Y				\$ 67	\$ 41	\$ 121								\$ 240
4	<b>Expense</b>															
5	Elkhorn BESS (Expense)	AB#														
6	<b>Project Capital Forecast</b>				\$ 11	\$ 15,527	\$ 86,121									
7	<b>Project Expense Forecast</b>															
8	<b>Total Project Forecast</b>				\$ 11	\$ 15,527	\$ 86,121									
9																
10																

**PACIFIC GAS AND ELECTRIC COMPANY**  
**APPENDIX B**  
**STATEMENTS OF QUALIFICATIONS**

**PACIFIC GAS AND ELECTRIC COMPANY  
STATEMENT OF QUALIFICATIONS OF  
ANDREW PAUL ABRANCHES**

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- Q 1 Please state your name and business address.
- A 1 My name is Andrew Paul Abranches, and my business address is Pacific Gas and Electric Company (PG&E), 6111 Bollinger Canyon, San Ramon, California.
- Q 2 Briefly describe your responsibilities at company.
- A 2 I am currently the Senior Director of Wildfire Risk Management for PG&E. I lead the teams responsible for PG&E’s Wildfire Mitigation Plan, Risk Modeling and Analytics work, Vegetation Strategy and Analytics, and Meteorology & Fire Science. I moved into this role in September 2020. Prior to September 2020, I was the Senior Director in Electric Operations (EO) responsible for Electric Business Operations responsible for driving strategic alignment on the annual and longer-term risk-informed work, resource and financial plan. I have served in the same capacity for Gas Operations (GO).
- Q 3 Please summarize your educational and professional background.
- A 3 I have over 14 years of experience at PG&E, where I have held leadership positions in Finance, Human Resources, GO, EO, and Risk Management. Prior to joining PG&E, I held roles in engineering, supply chain, product development, and process improvement at General Electric Healthcare and Northrop Grumman Corporation. I have a Bachelor’s degree in Mechanical Engineering from the California Polytechnic State University, San Luis Obispo, and I am a graduate of the University of Idaho, Utility Executive Program.
- Q 4 What is the purpose of your testimony?
- A 4 I am assuming the following testimony in PG&E’s 2023 General Rate Case:
- Exhibit (PG&E-4), “Electric Distribution”:
    - Chapter 3, “Electric Distribution Risk Management”:
      - Section A.1.
- Q 5 Does this conclude your statement of qualifications?
- A 5 Yes, it does.

1                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                   **STATEMENT OF QUALIFICATIONS OF DAVE CANNY**

3    Q 1    Please state your name and business address.

4    A 1    My name is Dave Canny, I'm currently working remotely as Pacific Gas and  
5           Electric Company (PG&E) transitions from its prior location at 77 Beale  
6           Street, San Francisco, California to 300 Lakeside Drive, Oakland, California.

7    Q 2    Briefly describe your responsibilities at PG&E.

8    A 2    I am Director of Electric Program Management, with responsibility for  
9           leading the Program Management Office that is coordinating design,  
10          implementation, and continuous improvement activities for the Enhanced  
11          Powerline Safety Settings Program

12   Q 3    Please summarize your educational and professional background.

13   A 3    I have a Bachelor of Arts in Environmental and Evolutionary Biology from  
14          Dartmouth College and a Master of Environmental Policy and Management  
15          in Resource Ecology from Duke University. I have worked for PG&E since  
16          2006, and I have held roles in Customer Care and have supported  
17          Emergency Response activities. Prior to PG&E, I worked for the National  
18          Ocean Service.

19   Q 4    What is the purpose of your testimony?

20   A 4    I am sponsoring the following testimony and workpapers in PG&E's 2023  
21          General Rate Case.

- 22          • Exhibit (PG&E-4), "Electric Distribution":
  - 23                  – Chapter 4.6, "Enhanced Powerline Safety Settings"; and
  - 24                  – Workpapers supporting Chapter 4.6, "Enhanced Powerline Safety
  - 25                  Settings."

26   Q 5    Does this conclude your statement of qualifications?

27   A 5    Yes.

1                                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                                   **STATEMENT OF QUALIFICATIONS OF JAMIE L. MARTIN**

3    Q 1     Please state your name and business address.

4    A 1     My name is Jamie L. Martin, I'm currently working remotely as Pacific Gas  
5            and Electric Company (PG&E) transitions from its prior location at  
6            77 Beale Street, San Francisco, California to 300 Lakeside Drive, Oakland,  
7            California.

8    Q 2     Briefly describe your responsibilities at the company.

9    A 2     I am Vice President of Undergrounding. In this role, I am responsible for  
10           leading the cross-functional effort to scale the Underground program to  
11           deliver on our commitment to underground 10,000 miles of PG&E's electric  
12           system.

13   Q 3     Please summarize your educational and professional background.

14   A 3     I have a Bachelor's degree in Finance from the University of San Francisco.  
15           Prior to PG&E, I worked at Grant Thornton LLP. At PG&E, I have held roles  
16           in Supply Chain, Business Finance and Planning, Investor Relations,  
17           Financial Analysis and Reporting, and Project Finance.

18   Q 4     What is the purpose of your testimony?

19   A 4     I am sponsoring the following testimony in PG&E's 2023 General Rate  
20           Case.

- 21           • Exhibit (PG&E-4), "Electric Distribution":
  - 22               – Chapter 4.3, "System Hardening, Enhanced Automation, and PSPS  
23                 Impact Mitigations":
    - 24                   • Section B.2 and Section C.1.a.2.

25   Q 5     Does this conclude your statement of qualifications?

26   A 5     Yes, it does.