STATE OF CALIFORNIA GAVIN NEWSOM, Governor

PUBLIC UTILITIES COMMISSION

505 VAN NESS AVENUE

SAN FRANCISCO, CA 94102-3298

FILED

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October 23, 2020

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TO PARTIES OF RECORD IN APPLICATION 18-12-009:

This is the proposed decision of Administrative Law Judges Rafael Lirag and Elaine Lau. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's December 3, 2020 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, *ex parte* communications are prohibited pursuant to Rule 8.2(c)(4)(B).

/s/ ANNE E. SIMON

Anne E. Simon
Chief Administrative Law Judge

AES:gp2
Attachment

Decision **PROPOSED DECISION OF ALJS LIRAG AND LAU**
(Mailed 10/23/2020)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2020. (U39M)	Application 18- 12-009

DECISION ADDRESSING THE TEST YEAR 2020 GENERAL RATE CASE OF PACIFIC GAS & ELECTRIC COMPANY

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DECISION ADDRESSING THE TEST YEAR 2020 GENERAL RATE CASE OF PACIFIC GAS & ELECTRIC COMPANY

Summary

Today's decision addresses the Test Year (TY) 2020 General Rate Case (GRC) application of Pacific Gas and Electric Company (PG&E).[1] The decision also adopts the Settlement Agreement involving most of the active parties to the proceeding, subject to certain modifications.

For TY2020, PG&E initially requested an increase of $1.058 billion or a 12.4 percent increase over its authorized base revenue requirement in 2019 of $8.518 billion. The Public Advocate's Office (Cal Advocates) and other parties recommended adjustments to PG&E's requests. The positions of PG&E and other parties were fully litigated in approximately four weeks of evidentiary hearings held in September and October of 2019.

Through the course of the proceeding, PG&E made various adjustments to its forecast resulting from changes in position, concessions, adjustments to calculations, correction of errors, etc. PG&E's adjusted forecast represents its final position prior to the settlement and the amounts reflected in the adjusted forecast are referred to in the decision as "PG&E's forecast."

After evidentiary hearings were concluded, various parties held settlement discussions which resulted in the filing of the Joint Motion to Adopt the proposed Settlement Agreement. The Settlement Agreement resolves all issues amongst the settling parties. The settlement proposes a base revenue requirement of $9.093 billion which represents an increase of approximately $575 million over PG&E's currently authorized revenue requirement.

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[1] A Glossary of the abbreviations used in this decision is attached to this decision as Appendix A.

The decision adopts all provisions in the Settlement Agreement except for several modifications which are summarized in the Conclusion section of the decision. The modifications include reduction of the authorized Community Wildfire Safety Program (CWSP) capital forecasts for 2021 and 2022. Other modifications reflect more stringent filing requirements for recovery of undercollections tracked by certain regulatory accounts and for closure of up to 10 customer services branch offices.

The above changes result in the adoption of a TY2020 revenue requirement of $9.102 billion[2] which is equal to the settlement amount and $474 million less than PG&E's initial request in its application. The adopted revenue requirement for TY2020 represents an increase of $584 million or a 6.9 percent increase over the authorized base revenue requirement for 2019. Appendix B of the decision contains the Summary of Earnings for TY2020.

The decision also adopts Post-Test Year (PTY) revenue requirement adjustments of $339 million for 2021 (a 3.7% increase) and $344 million for 2022 (a 3.6% increase). By comparison, the PTY adjustments requested in PG&E's application are increases of $454 million in 2021 (+4.7%) and $486 million in 2022 (+4.8%). In the Settlement Agreement, the PTY adjustments increases the revenue requirement by 3.5 percent in 2021 and 3.9 percent in 2022. The difference between the adopted and settlement PTY revenue requirements are due to the modification to the CWSP capital forecasts for 2021 and 2022. Appendix E of the decision contains the PTY Results of Operations.

The impact of the TY2020 revenue requirement on an average residential customer's monthly bill for 2020 is an increase of approximately $6.26 or

[2] This amount includes a $9 million adjustment from using 2018 recorded capital instead of the 2018 forecast.

3.4 percent[3] compared to their current monthly bill at the time the application was filed.[4] By comparison, PG&E's original request in its application would have resulted in a monthly bill increase of $10.57 or 6.4 percent in 2020.

However, because of timing considerations regarding when the TY and first PTY adjustment can be implemented, customers are expected to see a single adjustment that incorporates both 2020 and 2021 adjustments in their 2021 monthly bill. Therefore, in 2021, an average residential customer can expect to see a monthly bill increase of $12.55 ($9.86 for electric and $2.69 for gas) or 7.6 percent compared to their current monthly bill. The increase incorporates and reflects the revenue requirement increases for both 2020 and 2021. By comparison, if PG&E's original application had been approved in its entirety, an average residential customer would have been expected to see a monthly bill increase of $20.55 or plus 12.4 percent over their current bill.[5]

The adopted revenue requirement and PTY increases for PG&E will provide the necessary funds to allow it to operate its electric and natural gas transmission and distribution system safely and reliably and to fulfill customer service functions at reasonable rates.

Funding requests for continuing safety and compliance programs to mitigate wildfire risks, additional mitigation programs that are being added for

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[3] The bill impact includes an additional $31 million to account for the Residential Rate Reform Memorandum Account described in Section 2.5.8.2 of the Settlement Agreement.

[4] All bill impacts are based on monthly residential customer usage of 500 kWh and 34 Therms, assume a current base revenue requirement of $8.518 billion, and are relative to the current 2018 customer bill amount of $165.94 shown in Table 2 of the Application.

[5] Relative to current bills in 2020, customers can expect to see an increase of $13.01 or 7.0% compared to PG&E's original application increase of $21.54 or 11.6%. The 2020 bills have a higher monthly bill base due to changes in total revenues that occurred after filing of the application.

the first time as a result of PG&E's Risk Assessment Mitigation Phase, and CWSP O&M and capital costs represent a significant portion of PG&E's GRC funding being authorized.

Wildfire remains one of PG&E's top risks and the CWSP, an integrated wildfire mitigation strategy that incorporates a risk-based approach to identify and address PG&E's assets that are most at risk from the threat of wildfires and its associated events, is primarily responsible for performing wildfire risk assessment and identifying wildfire risk mitigation work. The CWSP has five main programs: (a) Enhanced Vegetation Management (EVM); (b) Wildfire System Hardening; (c) Enhanced Operational Practices; (d) Enhanced Situational Awareness; and (e) Other Support Programs.

Review of the Settlement Agreement was conducted by examining each major topic, analyzing the settlement terms and revenue amounts that the settling parties agree on, and making an analysis regarding reasonableness of each term and the settlement as a whole in light of the evidence presented and comments from parties.

The settlement also includes memorandums of agreement between PG&E and Small Business Utility Advocates, PG&E and Center for Accessible Technology, and PG&E and National Diversity Coalition.

The decision applies the four percent cap on the percentage of residential customer accounts that PG&E can disconnect from utility service in this GRC cycle pursuant to Decision 20-06-003. The decision also requires PG&E to submit reports in its next GRC regarding the annual replacement rate of load break oil rotary switches and a report on the impact of the revenue requirement increase on disconnections for nonpayment. Finally, the decision requires that PG&E's

risk showing in its next GRC comply with the Safety Model Assessment Proceeding settlement agreement adopted in Decision 18-12-014.

1. Procedural Background

On December 13, 2018, Pacific Gas and Electric Company (PG&E) filed Application (A.) 18-12-009 requesting authority to establish its gas, electric distribution, and electric generation base revenue requirement for its Test Year (TY) 2020 General Rate Case (GRC) which includes TY2020 and Post-Test Years (PTY) 2021 and 2022. For TY2020, the application requests an increase of $1.058 billion in or a 12.4 percent increase over its adopted revenue requirement in 2019 of $8.518 billion. For the PTYs, the application requests additional increases of $454 million in 2021 (+4.7 percent) and $486 million in 2022 (+4.8 percent).

Protests and Responses to the applications were timely filed on January 17, 2019 by the following parties:

Protests:

a. Alliance for Nuclear Responsibility (A4NR);[6]
b. The Public Advocates Office (Cal Advocates);
c. The National Diversity Coalition (NDC);
d. The Utility Reform Network (TURN);
e. L. Jan Reid (Reid); and
f. Joint Community Choice Aggregators (JCCA), which consists of East Bay Community Energy, Marin Clean Energy, Peninsula Clean Energy, Pioneer Community Energy, San Jose Clean Energy, and Sonoma Clean Power;

Responses:

[6] A4NR filed its Protest on January 11, 2019.

a. The Office of Safety Advocate (OSA);[7]
b. Silicon Valley Clean Energy (SVCE);
c. City and County of San Francisco (San Francisco);
d. County of Napa (Napa) and County of Sonoma (Sonoma);
e. Southern California Edison Company (SCE);
f. Coalition of California Utility Employees (CUE);
g. Energy Producers and Users Coalition (EPUC);
h. Indicated Shippers (IS); and
i. Solar Energy Industries Association (SEIA) and Vote Solar.

PG&E filed a Reply to the Protests and Responses on January 28, 2019.

Motions for party status were filed by the following entities and party status were granted as follows:

a. Transmission Agency of Northern California (TANC) on January 10, 2019 - motion was granted on January 15, 2019;
b. Reid on January 22, 2019 - motion was granted on January 28, 2019;
c. Small Business Utility Advocates (SBUA) on January 25, 2019 - motion was granted on January 28, 2019;
d. Center for Accessible Technology (CforAT) on January 30, 2019 - motion was granted on the same day;
e. Federal Executive Agencies (FEA) on February 7, 2019 - motion was granted on the same day;
f. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) on February 8, 2019 – joint motion was granted on February 11, 2019;

[7] The advocacy role of OSA was incorporated into SED effective January 1, 2020. For purposes of this proceeding, SED will be treated as the successor of OSA. However, because the testimonies and various pleadings filed reference OSA, the decision will keep this reference with the understanding that all requirements such as reviews to be conducted and reports to be submitted shall instead pertain to SED.

g. County of Mendocino (Mendocino) on February 11, 2019 – oral motion was granted at the Preliminary Hearing Conference (PHC);

h. California City/ County Streetlight Association (CALSLA) on February 11, 2019 – oral motion was granted at the PHC;

i. Alliance for Retail Energy Market and Direct Access Customer Coalition on February 11, 2019 – oral motion was granted at the PHC;

j. Monterey Bay Community Power (MBCP) on March 1, 2019 – motion was granted on March 4, 2019;

k. Kern County Taxpayers Association (Kern Tax) on March 6, 2019 – motion was granted on the same day;

l. Women's Energy Matters (WEM) on March 13, 2019 – motion was granted on the same day;

m. City of Santa Rosa (Santa Rosa) on March 19, 2019 – motion was granted on March 27, 2019; and

n. The Ad Hoc Committee of Senior Unsecured Noteholders to PG&E (Ad Hoc Committee) filed a motion for party status on November 1, 2019. The motion was granted on November 8, 2019. However, the Ad Hoc Committee subsequently filed a motion to withdraw as a party on January 24, 2020 which was granted in the ALJ ruling dated March 16, 2020.

On February 7, 2019, PG&E filed a motion requesting that the Commission issue an order that would make the revenue requirement authorized for TY2020 to be effective January 1, 2020 even if the decision authorizing the TY2020 revenue requirement is issued after that date. The motion also requests that the adopted revenue requirement shall include interest, based on a Federal Reserve three-month commercial paper rate. A proposed interim decision was issued by the assigned Administrative Law Judges (ALJ) on October 2, 2019 recommending approval of PG&E's motion regarding the effective date of the TY2020 revenue requirement and the addition of interest. In addition, the proposed decision directs PG&E to establish a GRC Memorandum Account (GRCMA) that will record the difference in the revenue requirement that is effective on January 1, 2020 and the final revenue requirement adopted in the TY2020 GRC decision. No comments or objections were filed and on November 7, 2019, the Commission issued Decision (D.) 19-11-004 adopting the proposed decision in its entirety.

A PHC was held on February 11, 2019 to discuss the issues of law and fact, the need for hearings, and the schedule for the proceeding.

On March 8, 2019, the assigned Commissioner issued a Scoping Memorandum and Ruling (Scoping Memo) setting forth the scope of issues and procedural schedule. The Scoping Memo also directed PG&E to timely serve to parties any developments in the Chapter 11 bankruptcy case that it filed on January 29, 2019, that would affect its requests in this proceeding. A ruling was issued by the assigned ALJs on March 13, 2019 clarifying the schedule for when rebuttal testimony is due.

On May 7, 2019, the assigned ALJs issued a ruling establishing Public Participation Hearings (PPH) in nine different locations. PPHs were held on July 9, 17, 18, 24, 25, 26, and 31, 2019 and on August 13 and 14, 2019.

On July 29, 2019, PG&E filed a motion to strike the prepared testimony of A4NR. Responses opposing PG&E's motion were filed by WEM on August 6, 2019, Reid on August 7, 2019, and by both TURN, and A4NR on August 13, 2019. A Response was also filed by CUE on August 13, 2019 supporting PG&E's motion. The assigned ALJs issued a ruling on September 6, 2019 denying PG&E's motion to strike.

Also, on July 29, 2019, TURN filed a motion for modification of the schedule to accommodate events in PG&E's Chapter 11 bankruptcy case. Responses to TURN's motion were filed by PG&E on August 2, 2019 and JCCA on August 9, 2019. At the evidentiary hearing on October 10, 2019, TURN's motion was denied without prejudice to raising the same motion or issues if events in PG&E's bankruptcy become more concrete.[8]

Evidentiary hearings were held from September 23, 2019 to October 18, 2019, and on November 6, 2019. Corrections to the hearing transcripts were adopted by ALJ ruling on November 20, 2019.

On October 7, 2019, PG&E filed a motion to strike the revised testimony of TURN on Deferred Work Settlement. TURN filed a Response to PG&E's motion. PG&E's motion to strike was denied during the evidentiary hearing on October 10, 2019 but PG&E was allowed to submit sur-rebuttal testimony regarding TURN's testimony on Deferred Work Settlement.[9]

On October 8, 2019, San Francisco filed a motion to enter into evidence the declaration of Douglas Lipps concerning PG&E's crossbore work in San Francisco. TURN filed a Response on October 16, 2019 supporting San Francisco's motion while PG&E filed a Response also on October 16, 2019 opposing San Francisco's motion. San Francisco's motion was granted in part during the evidentiary hearing on October 17, 2019.[10] On November 1, 2019, San Francisco filed a Response to admit a revised declaration of Douglas Lipps.

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[8] Transcript Volume 20 at 2223 to 2224.

[9] Transcript Volume 20 at 2224 to 2225.

[10] Transcript Volume 24 at 2783 to 2786.

The revised declaration was received into evidence during the evidentiary hearing on November 6, 2019.[11]

On November 1, 2019, TURN filed a motion to admit a late-filed exhibit into evidence. The motion was granted, and the late-filed exhibit was admitted into evidence during the evidentiary hearing on November 6, 2019.[12]

Also, on November 1, 2019, PG&E filed a brief regarding the application of Pub. Util. Code § 8386.3(e) to its 2019 Wildfire Mitigation Plan (WMP) capital expenditures. The brief was amended on December 31, 2019.

On November 8, 2019, the assigned ALJs issued a ruling adopting confidential modeling procedures relating to PG&E's Results of Operations (RO) model.

On November 12, 2019, A4NR filed a Motion for Oral Argument. The motion was granted on December 2 ,2019 with the exact date, time, and place to be set for a future ruling. PG&E likewise filed a motion for oral argument on January 3, 2020 which was granted on the same day.

On November 25, 2019, PG&E moved to admit late submitted errata to exhibits into evidence. The motion was granted on December 30, 2019.

On December 2, 2019, the assigned ALJs issued a ruling revising the schedule for filing of opening and reply briefs after being informed via several emails that a settlement motion would be filed and pursuant to various requests from parties to modify the remainder of the proceeding schedule. The adopted schedule also set dates for the filing of a motion for approval of a settlement agreement and dates for comments and responses to said settlement motion.

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[11] Transcript Volume 26 at 3083 to 3085.

[12] Transcript Volume 26 at 3085 to 3086.

On January 6, 2020, the following parties filed Opening Briefs regarding disputed issues that are outside the Settlement Agreement: A4NR; Reid; JCCA; and WEM.

On January 14, 2020, a Joint Motion for Approval of Settlement Agreement (Settlement Motion) was jointly filed by the following parties: PG&E; Cal Advocates; TURN; SBUA; CforAT; NDC; CUE; CALSLA; and OSA (collectively, settling parties).

On January 15, 2020, OSA filed a motion to change its name to The Safety and Enforcement Division (SED). A ruling granting the motion was issued on January 29, 2020.

On January 21, 2020, separate Comments to the Settlement Motion were filed by A4NR, FEA, L. Jan Reid, SEIA, WEM, and JCCA. Reply Comments were filed by SCE and SDG&E on February 5, 2020. A Joint Reply Comment was filed by the settling parties.

On January 23, 2020 Ad Hoc Committee filed a Motion to Withdraw as a party to this proceeding and to withdraw all pleadings they have filed. The assigned ALJs issued a ruling on March 6, 2020 approving the motion to withdraw as a party but denied the request to withdraw all pleadings that have been filed.

On January 27, 2020 PG&E filed a motion for official notice of facts contained in their 10-K Annual Reports showing total number of electric and gas customers for the years 2013-2018. JCCA filed a Response on February 11, 2020 as well as a motion for leave to file a sur-reply brief. PG&E filed a response to the motion to JCCA’s motion for leave to file a sur-reply on February 13, 2020. PG&E’s motion for official notice was partly granted in the ruling on

June 5, 2020. The ruling also required JCCA to revise its sur-reply brief. The revised sur-reply brief was filed by JCCA on June 22, 2020.

On February 5, 2020, Joint Reply Comments were filed by the settling parties in response to the Opening filed addressing issues that are outside the settlement.

On February 6, 2020, a joint motion to amend Appendix B to the Settlement Agreement was filed by PG&E and TURN. The motion was granted on April 29, 2020.

On May 15, 2020, the assigned ALJs issued a ruling requiring the settling parties to submit documents showing the impact of Article 3.2 of the Settlement Agreement. PG&E filed a Response on May 20, 2020. The response included the documents required by the ruling.

On August 13, 2020, the assigned ALJs issued a ruling adopting amended confidential modeling procedures in response to the novel coronavirus pandemic.

Also on August 13, 2020, PG&E filed a motion to amend the Settlement Agreement. JCCA filed a Response on August 28, 2020. The motion was granted on September 28, 2020.

This proceeding is deemed submitted on September 28, 2020 upon approval of PG&E's filing of amendments to the Settlement Agreement that address corrections and errors in calculations.

2. PPHs and Correspondence

The Commission held 17 PPHs in nine different locations throughout PG&E's service territory to listen to and solicit comments from PG&E's customers regarding the Application and PG&E's proposed rate increases. The PPHs were held in San Francisco, Stockton, Chico, Oakland, San Jose, San Luis

Obispo, Santa Rosa, Bakersfield, and Fresno. Each Commissioner attended at least one of the PPHs.

At each of the PPHs, informational and educational materials were provided about the Application and the CPUC's processes, including estimated bill impacts of the Application on an average residential electric and gas customer. Parties were given the opportunity to make presentations at the PPHs and PG&E made brief presentations about the Application at each of the PPHs. TURN made presentations at the San Francisco, Stockton, Oakland, Santa Rosa, and Fresno PPHs. Customer service representatives from PG&E were also required to be present at each of the PPHs to answer billing and service questions for the benefit of customers that came to the PPHs.

Almost all of PG&E's customers that spoke at the PPHs oppose PG&E's proposed rate increase. Many asserted that PG&E's proposed rate increases are not affordable, especially for people with low incomes and for people on fixed incomes such as the elderly or customers that are retired.

Many speakers voiced concerns about PG&E's poor safety record and history of delayed maintenance of critical infrastructure. These speakers requested increased transparency of PG&E's operations and accounting to ensure that PG&E spends money on safety appropriately. Some customers advocated that PG&E underground its power lines to mitigate wildfire risks. At the Chico PPHs, many of those attending the PPHs were survivors of or have friends and family who were survivors of the 2018 Camp Fire.

A number of customers at several PPHs also spoke against PG&E's Public Safety Power Shutoff program and voiced concerns that PG&E has not adequately prepared and mitigated risks of a power shutoff event for vulnerable segments of population, such as the elderly, disabled, and those who depend on ventilators or other critical life support equipment.

In addition to the comments at the PPHs, many letters, emails, and other written correspondence have been received from the public. Many reiterate the concerns voiced at the PPHs, such as the unaffordability of PG&E's proposed rate increase, PG&E's poor safety and maintenance operations, and the need for increased transparency of PG&E's operations and accounting of money. A letter from the Board of Supervisors of San Joaquin County was also received expressing concerns about the proposed rate increase to the people in their community.

3. Background of the Application

PG&E is one of the largest combined natural gas and electric energy companies in the United States. The company is a regulated public utility that provides natural gas and electric service to approximately 16 million people through approximately 5.4 million electric customer accounts and 4.3 million natural gas customer accounts.

Its service territory consists of approximately 70,000-square-miles in northern and central California stretching from Eureka in the north to Bakersfield in the south, and from the Pacific Ocean in the west to the Sierra Nevada in the east.

PG&E's electric distribution system is comprised of approximately 106,681 circuit miles of electric distribution lines and 18,466 circuit miles of interconnected transmission lines while its gas distribution system is comprised of approximately 42,141 miles of natural gas distribution pipelines and 6,438 miles of transmission pipelines.

In its GRC application, PG&E requests that the Commission authorize an increase to PG&E's electric and gas rates and charges effective January 1, 2020. Specifically, PG&E requests that the Commission increase 2020 gas and electric distribution and generation base revenue requirements by a total of $1.058 billion or 12.4 percent[13] over the 2019 adopted revenue requirement of $8.518 billion. This proposed increase will increase a typical residential customer's electric and gas customer bill by approximately 6.4 percent, or $10.57 per month, for PG&E's typical residential electric and gas customer. According to PG&E, the above revenue requirement is what PG&E needs to provide safe and reliable gas and electric service to its customers and includes work that reflects new approaches to the design, construction, and operations and maintenance (O&M) of its electric distribution system to focus on and address increased wildfire risks particularly in high fire-risk locations.

In addition to its request for 2020, PG&E requests PTY revenue requirement increases of $454 million in 2021 (an annual increase of 4.7 percent), and $486 million in 2022 (an annual increase of 4.8 percent). According to PG&E, the PTY increases are primarily related to capital investment, which drives increases in rate base and depreciation expense, irrespective of inflation.

Many parties to the proceeding reviewed PG&E's application and oppose various requests and recommend adjustments to PG&E's requests.

4. Settlement Agreement

On December 20, 2019, after the close of evidentiary hearings, a Joint Motion for Approval of Settlement Agreement (Settlement Motion) was filed by

[13] This amount represents PG&E's initial and unadjusted forecast.

the following parties: PG&E; Cal Advocates; TURN; SBUA; CforAT; NDC; CUE; CALSLA; and OSA.

The Settlement Motion requests approval of the Settlement Agreement (Settlement Agreement) which is included as Attachment 1 to the Settlement Motion. According to the settling parties, the Settlement Agreement resolves all issues amongst the settling parties to wit: "the Settlement Agreement is a compromise among the settling parties' respective litigation positions to resolve all disputed issues the settling parties raised in this proceeding."[14] A summary of the settling parties' various litigation positions prior to the settlement were also included in the Settlement Motion.[15]

4.1. Description of the Settlement Agreement

The settling parties have agreed to a TY2020 revenue requirement of $9.093 billion which represents an increase of $575 million over previously authorized 2019 rates.[16] By comparison, PG&E initially requested an increase of $1.058 billion over currently authorized rates which was later reduced to $1.003 billion.[17] In its prepared testimony, Cal Advocates had initially recommended an increase of $503 million[18] which it later adjusted to $581 million due to a stipulation and other concessions.[19]

Additionally, the settling parties agree to allow PG&E to collect the amounts removed from its GRC forecast for the 2020 to 2022 Residential Rate

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[14] Settlement Agreement at 1 to 2.

[15] Settlement Motion at 5 to 11.

[16] Settlement Agreement at 1.

[17] The amount of $1.058 billion was adjusted to $1.003 billion due to concessions, errata, and forecast updates per Exhibit 312 at Table 5A at 5-3.

[18] Exhibit 248 at 2 to 3 Table 01-1.

[19] Exhibit 312 at 5-3 Table 5A.

Reform Memorandum Account (RRRMA) costs in rates, subject to refund, through PG&E's Annual Electric True-up (AET) advice letter. This provision is discussed in the Customer Care section (Chapter 9) of this decision.

For PTYs 2021 and 2022, the settling parties agree to adopt respective increases of 3.50 percent or $318 million for 2021 and 3.90 percent or $367 million for 2022.[20] By comparison, PG&E's original request was increases of $454 million in 2021 (4.7 percent) and $486 million in 2022 (4.8 percent) while Cal Advocates' original recommendation was for increases of $301 million in 2021 and $332 million in 2022.

The summary of the Settlement Agreement includes the following:

A. Overall Revenue Requirement Provisions

This section contains the summary of the overall revenue requirements for TY2020 and PTYs 2021 and 2022 that the settling parties have agreed on. As stated above, the settling parties have agreed to a TY2020 revenue requirement of $9.093 billion or a $575 million increase over authorized rates for 2019, and additional increases of $318 million in 2021 and $367 million in 2022.

B. Summary of Change to PG&E's Forecast

This section contains the settling parties' agreements regarding various O&M and capital forecasts as well as all other issues relating to the following topics: (a) Gas Distribution; (b) Electric Distribution; (c) Energy Supply; (d) Customer Care; (e) Shared Services and Information Technology (IT); (f) Human Resources; (g) Administrative and General (A&G); (h) Results of Operations (RO); (i) Balancing and Memorandum Accounts; and (j) Other Adjustments.

C. Other Terms

[20] Settlement Agreement at 2.

This section includes terms concerning: (a) Safety Policy Issues; (b) Deferred Work Principles; (c) Risk Showing; and (d) Safety Related Earnings Adjustment Mechanisms.

D. General Provisions

This section contains many of the general provisions that are common to these types of settlements such as resolution of issues, entirety of the agreement, terms about rejection or modification of the settlement, severability, effective date, etc.

Appendices

Appendix A contains the RO summary of proposed revenue increases.

Appendix B contains the Comparison Exhibit which provides a comparison between the settlement amounts and amounts proposed by parties. The Comparison Exhibit is intended by the settling parties to fulfill the requirement of Rule 12.1 of the Commission's Rules, which states in part:

> "When a settlement pertains to a proceeding under a Rate Case Plan or other proceeding in which a comparison exhibit would ordinarily be filed, the motion must be supported by a comparison exhibit indicating the impact of the settlement in relation to the utility's application and, if the participating staff supports the settlement, in relation to the issues staff contested, or would have contested, in a hearing."

Appendix C contains the PTY settlement amounts.

Appendix D contains the average service lives, mortality curves, net salvage values, percentages, and accrual rates of PG&E's asset groups.

Appendix E contains the memorandum of understanding between PG&E and SBUA.

Appendix F contains the memorandum of understanding between PG&E and C for AT.

Appendix G contains the joint stipulation between PG&E and NDC.

Appendix H contains the Diablo Canyon Power Plant (DCPP) cancelled projects and amortization schedule.

Appendix I contains the O&M labor factors by Unbundled Cost Category (UCC) to allocate common costs.

4.2. Standard for Review

With respect to any settlement agreement, pursuant to Rule 12.1 of the Rules of Practice and Procedure, we will only approve settlements that are reasonable in light of the record as a whole, consistent with the law, and is in the public interest. And, in order to consider the proposed Settlement Agreement in this proceeding as being in the public interest, we must be convinced that the parties have a sound and thorough understanding of the application and all of the underlying assumptions and data included in the record. This level of understanding of the application and development of an adequate record is necessary to meet our requirements for considering any settlement.

5. Analysis Overview

This section provides a general overview of how we analyzed PG&E's revenue requirement, the terms of the Settlement Agreement, issues outside the Settlement Agreement, and other issues including issues relating to PG&E's Risk Assessment Mitigation Phase (RAMP)

The decision generally follows the topics in Articles 2 to 6 of the Settlement Agreement. The decision examines each major topic, analyzes the settlement terms and revenue amounts that the settling parties agree on, and makes an analysis as to the reasonableness thereof in light of the evidence presented and comments from parties.

In each section, we provide a background of the topics being examined, a brief description of the particular costs and other requests being addressed, and a comparison of parties' positions[21] with the terms set forth in the Settlement Agreement. The settlement terms and positions of various parties are summarized followed by a discussion and analysis of the reasonableness of each of the settlement terms and amounts as well as objections and counterproposals by other parties. In addition, we examined whether the amounts proposed in the Settlement Agreement are sufficient to address safety-related and RAMP-related concerns as applicable.

We then examine, analyze, and provide a discussion of costs and issues that are outside of the Settlement Agreement generally following the same methodology described above.

Since the evidence and arguments in this proceeding are voluminous, and the Settlement Agreement resolves most of these issues, we focused our attention on the major points of contention and did not summarize each party's positions on each individual issue. However, we reviewed all the exhibits in this proceeding pertaining to each section, the evidentiary hearing transcripts, and all arguments and positions raised by all parties, including initial positions by parties prior to the Settlement Agreement. We also considered the state of the economy and the economic outlook described in the parties' exhibits. All the above were applied in deciding whether or not the revenue requirements proposed for TY2020, PTYs 2021 and 2022, and other terms in the Settlement Agreement are reasonable and whether these should be adopted, modified, or denied.

[21] This includes initial positions and testimony from the settling parties.

The decision includes tables showing PG&E's adjusted forecasts and those adopted in the Settlement Agreement. In presenting PG&E's forecasts, for convenience and easier clarity, the decision often presents PG&E's adjusted forecasts as opposed to the initial forecasts that appear in PG&E's direct testimony and workpapers. The updated forecasts represent PG&E's final positions prior to the Settlement Agreement resulting from corrections and possible concessions after evidentiary hearings. However, in several instances such as in the background and other preliminary sections, the original forecasts and total revenue requirement requests may be referenced because these are more known to the general public. These original totals are what appear in the application, in most testimonies, and the sums referred to during hearings and PPHs. However, as stated above and for consistency and easier understanding, the decision for the most part, references PG&E's adjusted forecasts in tables and in discussions of the various substantive chapters throughout the decision.

The decision also considers PG&E's capital forecasts for 2018 but with the understanding that the 2018 capital forecasts are subject to adjustment using 2018 recorded capital expenditures pursuant to Article 3.2 of the Settlement Agreement. This topic is discussed in greater detail in the Other Adjustments section of the decision.

Attachment B of this decision contains the adopted statement of earnings tables for PG&E while Attachment C of this decision contains the adjustments that we adopt to PG&E's proposed revenue requirement. Attachment D contains details of the authorized revenue requirements for post-test years (PTY) 2021 and 2022. The statement of earnings table sets forth all the components of the revenue requirement consisting of the total O&M costs, and the capital-related costs that are necessary to support PG&E's rate base. The statement of earnings table shown in Attachment B also reflects all of the costs or methodologies we have found to be reasonable as inputs into the Results of Operation (RO) model, which is used by PG&E to generate the revenue requirement amount that is needed to allow it to earn the authorized rate of return on its investments.

The above review and evaluation process results in the revenue requirement that is appropriate for PG&E to provide safe and reliable service at just and reasonable rates, as required by Pub. Util. Code § 451.

6. Gas Distribution

This section addresses the O&M, capital, and other requests relating to PG&E's Gas Distribution organization. PG&E's natural gas distribution system is comprised of approximately 42,800 miles of distribution mains, 3.5 million gas services, and 4.5 million gas meters.[22] The distribution system provides natural gas to PG&E's approximately 4.3 million residential, commercial, and industrial customers.

In Article 2.2.1 of the Settlement Agreement, the settling parties agree to adopt $369.1 million[23] for O&M expenses for TY2020. For capital, the settling parties agree to adopt $968.837 million for 2018, $933.188 million for 2019, and $1.022 billion for 2020. Pursuant to Article 3.2 of the settlement, the adopted forecast for 2018 capital costs is subject to the adjustment described in said article which is discussed in greater detail in the Other Adjustments section of the decision.

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[22] Exhibit 10 at 1-1.

[23] PG&E's forecast is actually $369.080 million. The amount indicated in Article 2.2.1 is rounded up.

6.1. O&M

Gas distribution O&M expenses are for operations work activities related to labor and expenses, storage, operations supervision and engineering, main and service expenses, measurement and regulator storage expenses, other gas distribution expenses, maintenance supervision and engineering, maintenance of mains and services, measurement and regulator station expenses, maintenance of meters and house regulators, and maintenance of other equipment.[24] Some of the specific work performed by Gas Distribution includes leakage surveys, leak repairs, application of corrosion control measures, valve maintenance, monitoring meter accuracy, adding odorant to gas, and locating and marking buried pipes to avoid damage caused by third-party dig-ins.

As stated above, the settlement adopts a forecast of $369.080 million for TY2020 O&M expenses. By comparison, O&M expenditures in 2017 were $339.4 million and $346.7 million in 2018.[25] The settlement reduces PG&E's proposed forecast of $374.490 million by $5.0 million. In addition, $0.410 million in reductions is further applied due to labor escalation adjustments also adopted in the settlement. Generally, the labor escalation adjustments adopted in the settlement are lower than PG&E's originally proposed escalation rates. Reasonableness of the labor escalation rates adopted in the Settlement is discussed in the Human Resources section of the decision.

PG&E's Gas Distribution organization is comprised of eight organizations: (a) Asset Family Distribution and Mains; (b) Asset Family Measurement & Control and Compressed Natural Gas Stations (CNG); (c) Gas Distribution

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[24] Exhibit 181 at 1.

[25] *Ibid*.

Operations and Maintenance Programs; (d) Corrosion Control; (e) Leak Management; (f) Gas System Operations; (g) New Business and Work at the Request of Others (WROs); and (h) Gas Operations Technology & Other Distribution Support.

6.1.1. Asset Family Distribution and Mains

Costs under this category relate to expenses for PG&E's Distribution Integrity Management Program (DIMP), Meter Protection Program (MPP), pipeline replacement programs, service replacement programs, and other gas distribution reliability work. The above programs are primarily focused on analysis, inspection, and replacement of Gas Distribution assets for purposes of improving safety and complementing ongoing maintenance carried out through other Gas Distribution programs.

The settlement adopts a $5.0 million reduction to PG&E's proposed TY2020 forecast for the MPP as shown in the table below. Further reduction of $32,000 is the result of labor escalation adjustments incorporated in the settlement amount.

Asset Family Distribution and Mains	PG&E Forecast	Settlement Reduction	Settlement Amount
Meter Protection	$13,238,000	$5,016,000	$8,222,000
Corrective Maintenance	$2,669,000	$3,000	$2,666,000
Integrity Management	$39,076,000	$13,000	$39,063,000
Total	**$54,983,000**	**$5,032,000**	**$49,951,000**

Meter Protection

The Meter Protection primarily relates to the creation of the MPP. The MPP includes protection of exposed meters from vehicular damage and installation of service valves where existing valves are inaccessible. Other Meter protection activities include inspections to confirm field conditions, installation of bollards, other instances of valve installation, and relocation of meter sets.

Corrective Maintenance

Corrective Maintenance includes activities associated with repair of main valves, maintenance and repair of failed or inoperative regulation equipment, replacement of inoperable valves, repair of Supervisory Control and Data Acquisition (SCADA) units resulting from alarms and abnormal operating conditions (AOC), and repairs performed on high-pressure regulators.

Integrity Management

The DIMP monitors, assesses, and mitigates risks to PG&E's gas distribution system.

6.1.2. Asset Family Measurement & Control and CNG

Costs under this section relate to the gas distribution portions of the Measurement & Control and CNG asset families, operation of these assets, and mitigation of specific risks to these assets. Measurement & Control includes PG&E's Overpressure Protection (OPP) Enhancement Program which is designed to incorporate industry best practices, mitigate equipment-related threats, and incorrect operations at regulator stations. The settlement adopts PG&E's forecasts with slight reductions resulting from labor escalation adjustments adopted in the Settlement Agreement.

Asset Family Measurement & Control and CNG	PG&E Forecast	Settlement Reduction	Settlement Amount
Preventive Maintenance	$3,165,000	$4,000	$3,161,000
Manage Energy Efficiency	$3,776,000	$2,000	$3,774,000
Total	**$6,941,000**	**$6,000**	**$6,935,000**

Preventive Maintenance

Preventive Maintenance includes work required to comply with pipeline safety regulations which require PG&E to conduct routine and periodic maintenance of its gas distribution system. Preventive maintenance work also includes maintenance of SCADA field equipment, regulator stations, farm taps, main and service distribution valves, air conditioning inspections, and overall gas maintenance support.

Manage Energy Efficiency

Manage Energy Efficiency includes ongoing CNG station program expenses which focus on the operation and maintenance of the CNG stations and as well as mobile compression units. Federal and state codes require periodic maintenance of CNG stations to minimize safety risks.

6.1.3. Distribution Operations and Maintenance Programs

Maintenance activities of PG&E's gas distribution facilities are divided into three major functions: Distribution Operations and Maintenance Programs; Corrosion Control; and Leak Management. This section discusses Distribution Operations and Maintenance Programs which include activities for Locate and Mark, Field Services, and Preventive and Corrective Maintenance. The settlement adopts all of PG&E's forecasts with slight reductions resulting from labor escalation adjustments that were also adopted by the settlement. Parties do not object to PG&E's TY2020 forecasts for this category.

Distribution Operations and Maintenance Programs	PG&E Forecast	Settlement Reduction	Settlement Amount
Provide Field Service	$43,646,000	$74,000	$43,572,000
Locate and Mark	$44,013,000	$60,000	$43,953,000
Preventive Maintenance	$17,077,000	$21,000	$17,056,000
Corrective Maintenance	$10,420,000	$10,000	$10,410,000
Change/Maintain Used Gas Meters	$1,828,000	$0	$1,828,000
Integrity Management	$2,480,000	$0	$2,480,000
Total	**$119,464,000**	**$165,000**	**$119,299,000**

Provide Field Service

Gas Field Services manages customer generated requests that require site visits by Gas Service Representatives (GSR). Costs include investigating reports of possible gas leaks, carbon monoxide monitoring, customer requests for starts and stops of gas service, appliance pilot re-lights, and appliance safety checks. GSRs also perform maintenance work, remediation work, meter set leak repairs, and regulator replacements. In some situations, GSRs act as first responders in emergency situations.

Locate and Mark

Locate and Mark includes work to comply with Federal pipeline regulations and state law. Builders, contractors and others planning to excavate these systems are required to notify underground facility owners, such as PG&E, of any intent to excavate.

Preventive Maintenance

Preventive maintenance work includes maintenance of SCADA field equipment, regulator stations, farm taps, main and service distribution valves, air conditioning unit inspections, and overall gas maintenance support.

Corrective Maintenance

Corrective maintenance includes work required to repair or replace damaged or failed gas facilities as well as necessary restoration identified during preventive maintenance inspections.

Change/Maintain Used Gas Meters

Costs under this category are for replacement of gas service and meter equipment such as bent risers, broken or damaged service valves, and remediation work to address an AOC.

Integrity Management

Costs for Integrity Management include activities related to PG&E's DIMP. DIMP consists of various elements associated with assessing, monitoring, and mitigating risk. It includes evaluating the gas distribution system, ranking risks, and prioritizing mitigation activities. DIMP also requires PG&E to collect information about its distribution pipelines, identify and assess applicable threats to its distribution system, evaluate risks to the distribution system, determine and implement measures designed to reduce risks from failure, and evaluate the effectiveness of mitigation measures.

6.1.4. Corrosion Control

This section addresses activities relating to risk assessment and activities to reduce risks arising from corrosion of gas distribution assets. The settlement adopts PG&E's TY2020 forecasts with slight reductions resulting from labor escalation adjustments also adopted by the settlement.

Corrosion Control	PG&E Forecast	Settlement Reduction	Settlement Amount
Cathodic Protection	$20,193,000	$22,000	$20,171,000
Preventive Maintenance	$2,261,000	$2,000	$2,259,000
Corrective Maintenance	$5,013,000	$5,000	$5,008,000
Total	**$27,467,000**	**$29,000**	**$27,438,000**

Cathodic Protection

Underground distribution facilities are protected from external corrosion through the application of Cathodic Protection. Programs addressing these needs include monitoring, troubleshooting, maintenance, enhanced survey, and isolated steel services. Other programs classified under Cathodic Protection are programs relating to unprotected mains, casing test stations, casing contact mitigation, casing monitoring, and corrosion support.

Preventive Maintenance

Preventive maintenance under Corrosion Control involves creation of the Atmospheric Corrosion Inspection and Mitigation program. This program conducts follow up inspections when access to assets such as meters is hindered. The program then takes steps to mitigate atmospheric corrosion of above ground distribution assets.

Corrective Maintenance

Corrective Maintenance under Corrosion Control includes work required to repair or replace damaged or failed gas facilities. In many cases, the need for restoration is identified during preventive maintenance inspections of both low-pressure and high-pressure equipment and assets.

6.1.5. Leak Management

Costs under this section address PG&E's Leak Management programs consisting of gas leak surveys, leak grading, gas leak repairs, and gas service and main replacements.[26] These programs aim to mitigate safety and reliability risks to the gas distribution system and to reduce greenhouse gas emissions.

Leak Management	PG&E Forecast	Settlement Reduction	Settlement Amount
Leak Survey	$24,356,000	$27,000	$24,329,000
Corrective Maintenance	$42,212,000	$45,000	$42,167,000
Total	**$66,568,000**	**$72,000**	**$66,496,000**

PG&E also requests modification of the New Environmental Regulation Balancing Account (NERBA) and Natural Gas Leak Abatement Program

[26] Exhibit 10 at 8-1.

Balancing Account (NGLAPBA). The specific modifications requested are discussed in a later section of this chapter.

Leak Survey

Leak Survey includes cost for conducting daily leak surveys. These include traditional surveys conducted by operator qualified leak surveyor technicians and mobile surveys using the Picarro Leak survey technology.[27] These surveys are conducted on PG&E's gas distribution pipeline systems such as services mains and other gas assets.

Corrective Maintenance

Leak Repair Corrective Maintenance relates to repair of damaged or failed facilities. Gas facilities requiring repair are mostly identified through leak surveying activities although a small percentage of leaks may also be identified through customer odor complaints, employees performing other maintenance, and third-party dig-ins.

6.1.6. Gas System Operations

Costs under Gas Systems Operations support activities relating to planning and operating PG&E's gas distribution system as well as maintain sufficient design day capacity on the system. PG&E's forecast also includes engineering for local gas distribution facilities within each of PG&E's divisions and activities related to manual operation of certain gas facilities in the field. Parties do not oppose PG&E's TY2020 forecast which the settlement adopts, less slight reductions from labor escalation adjustments also adopted by the Settlement Agreement.

[27] Picarro solution technology uses mobile technology to capture leak data at scale. Data analytics, workflow automation, and reporting tools streamline the entire process.

Gas System Operations	PG&E Forecast	Settlement Reduction	Settlement Amount
Operate System	$8,999,000	$12,000	$8,987,000
System Modeling	$6,275,000	$10,000	$6,265,000
Total	**$15,274,000**	**$22,000**	**$15,252,000**

Operate System

Gas Distribution System Operations costs consist of two main activities: Gas Distribution Control Center Operations (GDCC); and Manual Field Operations. The GDCC enables Gas Systems Operations to mitigate system risk by integrating operations, capacity planning, integrity management, maintenance, and repairs into a coordinated effort that is monitored and supervised from a single location. On the other hand, Manual Field Operations must be performed from time to time to connect and calibrate pressure test gauges and recorders, to retrieve and replace paper charts from the recorders, to remove incidental pipeline liquids, and to perform similar activities.

Gas Transmission and Distribution System Modeling

Gas Distribution Planning & Operations Engineering consists of Gas System Planning and Gas Distribution Portfolio Management Engineering. Gas System Planning focuses on computerized modeling of hydraulically independent systems within the gas distribution system to meet service standards. On the other hand, Gas Distribution Portfolio Management and Engineering conducts non-hydraulic engineering and related professional work to support PG&E's gas distribution system.

6.1.7. New Business and WROs

New Business activities consist of installing gas infrastructure required to connect new customers to PG&E's distribution systems and to accommodate increased load from existing customers. On the other hand, WROs activities consist of relocating PG&E's existing gas distribution and service facilities at the request of governmental agencies or other third parties. In addition, activities for both New Business and WRO include customer contact, design and engineering, job cost estimation, contract preparation, construction, inspection of third-party work, and facility mapping.[28] The settlement adopts PG&E's forecast less slight reductions for labor escalation adjustments. Parties did not object to PG&E's forecasts for New Business and WROs.

New Business and WROs	PG&E Forecast	Settlement Reduction	Settlement Amount
WRO Maintenance	$5,951,000	$5,000	$5,946,000
Total	**$5,951,000**	**$5,000**	**$5,946,000**

WRO Maintenance

Gas WRO Maintenance costs covers work required by tariff and franchise agreements. This includes non-plant relocations and alterations of gas facilities. The forecast is directly impacted by WRO capital expenditures.

6.1.8. Gas Operations Technology & Other Distribution Support

Costs under this section relate to O&M work in the following areas: gas distribution technology; maintaining IT applications and infrastructure; Research and Development (R&D) and deployment; mapping support; training and curriculum development; gas distribution operations support; emergency work; operational management; and operational support. Once again, the settlement adopts PG&E's forecasts with slight reductions from labor escalation adjustments also adopted by the settlement.

[28] Exhibit 10 at 10-1.

Gas Operations Technology & Other Distribution Support	PG&E Forecast	Settlement Reduction	Settlement Amount
Other Distribution Operational Support	$17,286,000	$8,000	$17,278,000
Develop & Provide Training	$4,796,000	$0	$4,796,000
System Mapping	$4,276,000	$7,000	$4,269,000
R&D and Deployment	$3,405,000	$2,000	$3,403,000
Maintain IT Apps and Infrastructure	$12,558,000	$5,000	$12,553,000
Operational Management	$17,050,000	$26,000	$17,024,000
Operational Support	$18,471,000	$29,000	$18,442,000
Total	**$77,842,000**	**$77,000**	**$77,765,000**

Other Gas Distribution Operational Support

Costs forecast under this category encompass general support expenses incurred for supporting emergent work relating to PG&E's gas operations. Programs include the Engineer Rotation Development Program, gas consulting contracts, quality management, industry association dues, and the High-Pressure Regulator Conversion Program.

Develop & Provide Training

Training and curriculum development captures costs of activities related to training which include course development, content, and assessments. PG&E develops the technical training materials needed to maintain a skilled, safe and qualified workforce.

System Mapping

Gas Distribution System Mapping tracks essential asset information such as size, material type, location, configuration, and other related information for approximately 22,000 distribution maps needed to identify PG&E's gas distribution system. Costs also include maintaining distribution asset information in the Geographic Information System (GIS) and System Application and Products (SAP) systems.

R&D and Deployment

The R&D and Deployment Program is responsible for detecting, developing, testing, and introducing new methods and technologies for Gas Operations to improve gas safety, reliability, and efficiency.

Maintain IT Apps and Infrastructure

Costs under this category involve technology, strategy, and planning (TSP) relating to business technology strategy which enables gas operations to identify, plan, prioritize, and execute the correct work. TSP utilizes an integrated planning process to identify business requirements and prioritize funding.

Operational Management and Operational Support

Operational Management and Operational Support overhead costs cover cost centers that supervise, support, or manage employees who charge their time to specific orders.

6.1.9. Positions of the Parties

The Settlement Agreement adopts a $5 million reduction to PG&E's forecast for MPP and reductions totaling approximately $0.410 million from labor escalation adjustments.

Cal Advocates originally recommended reductions in Asset Family Distribution and Mains, Asset Family Measurement & Control and CNG, Corrosion Control, and Other Gas Distribution Operational Support.
Cal Advocates also opposed the proposed modification to the NERBA to record below ground Grade 3 leak repair costs. Instead, Cal Advocates had proposed to track the costs in the Natural Gas Leak Abatement Program Balancing Account (NGLAPBA).

TURN originally recommended reductions forecasts for the MPP and Cross-Bore Program. Both cost categories are under Distribution and Mains.

PG&E agreed to revise its monthly workplan for Locate and Mark activities in response to recommendations from CUE and revised its FERC allocation factors accepting JCCA's proposed split between electric and gas distribution for this GRC cycle. PG&E will propose an updated allocation factor methodology for Locate and Mark activities in its next GRC. We find that these commitments by PG&E resolve the O&M issues raised by CUE and JCCA for Gas Distribution.

6.1.10. Discussion

There were no objections to PG&E's forecasts for Distribution Operations and Management Programs, Leak Management, Gas System Operations, and New Business and WROs. We reviewed the costs adopted in the settlement for these organizations and find them reasonable.

Costs for Distribution Operations and Management Programs is forecast to increase by approximately $17.7 million compared to recorded expenses in 2017 primarily due to increases for Damage Prevention ($12 million) and Preventive and Corrective Maintenance ($5 million).[29] Higher costs are primarily associated with increased activities to mitigate key risks identified in PG&E's RAMP Report. Locate and Mark activities are expected to increase by approximately six percent in part because of increased construction and higher call volumes prior to diggings. Higher call volumes stem from increased awareness. PG&E is also improving project documentation resulting in longer completion times for Locate activities. For Preventive and Corrective Maintenance, higher cost drivers are

[29] Exhibit 10 table 6-7.

associated with increase in repairs and replacement of gas and meter equipment.[30]

The TY2020 forecast for Leak Management is approximately $6.5 million higher than 2017 recorded expenses of $59.9 million. The main driver for the increase is PG&E's transition from a four-year to a three-year compliance survey for leaks. This means more leak surveys are scheduled to be performed annually.[31]Another driver for increased costs is increased work to address key risks identified during PG&E's RAMP process.[32]

For Gas System Operations, the forecast for TY2020 is approximately $1.4 million higher than recorded costs of $13.86 million in 2017. Costs and activities are projected to remain the same with the slight increase due to cost escalation of 2017 expenditures.

Similarly, costs for New Business and WROs are expected to remain flat with activities performed during the base year continuing in TY2020. The slight increase in the forecast is primarily due to escalation.

Asset Family: Distribution and Mains

Cal Advocates and TURN originally recommended reductions to PG&E's forecasts for Meter Protection and Integrity Management. Cal Advocates had recommended a reduction of approximately $6.2 million while TURN recommended $7.5 million less than PG&E's forecast of $13.2 million.

PG&E's expense request is for remediation work of AOCs identified through field observations and other programs such as the Leak Survey program. An AOC is defined as a condition identified by a PG&E operator

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[30] Exhibit 10 at 6-24 to 6-25.

[31] Exhibit 10 at 8-7.

[32] Exhibit 10 at 8-2 and 8-10 to 8-11.

which may indicate a malfunction of a component, or a deviation from normal operations which in turn may indicate an operating condition that could exceed design limits and result in hazards to persons, property, or the environment.[33]

From 2014 to 2017, PG&E identified approximately 39,038 AOCs such as encroachments or danger from vehicular damage, which may need follow-up. No remediation work has been conducted to address the above AOCs and PG&E proposes to conduct remediation work during this GRC cycle that will eliminate the backlog in its entirety. TURN and Cal Advocates argue that the remediation work should be conducted at a slower pace as AOC meter locations are being supported by programs other than the MPP and because remediation work for AOCs is classified as low-risk. On the other hand, PG&E argues that the remediation work should be accomplished within the three-year timeframe it proposes.

From the evidence presented and arguments by parties, we find that PG&E did not sufficiently establish why the AOC backlog must be completed within three years as opposed to within five years as recommended by Cal Advocates, or eight years as recommended by TURN. As pointed out by Cal Advocates and TURN, the AOC backlog began being identified in 2014 but PG&E has not commenced any remediation work to address these and is only doing so now. As the proponent for its requests, PG&E has the burden of justifying its requests and we find that PG&E failed to demonstrate why its proposal is superior to that of Cal Advocates and TURN.

With respect to the proposed reduction agreed-upon in the settlement, we find the proposed reduction of $5.0 million represents a fair compromise

[33] Exhibit 181 at 7.

between recommendations from PG&E, Cal Advocates and TURN. This level of funding results in a pace of AOC remediation work that more accurately reflects the level of work that will be conducted based on the testimony presented and considering the issues that Cal Advocates and TURN raised initially. Thus, we find the settlement amount of $8.222 million for MPP costs reasonable and should be adopted.

Cal Advocates and TURN had also recommended reductions of $6.3 and $12.8 million respectively to PG&E's forecast of $39.1 million for DIMP, or more specifically, the Cross-Bore Program. The Cross-Bore Program is one of the programs that form part of PG&E's DIMP.

Based on PG&E's testimony, the Cross-Bore Program was developed to inspect, identify, and remediate installed cross bores within the gas distribution using trenchless technology. The program utilizes video equipment to inspect waste water lines and laterals for potential cross bore situations, and then repairs cross bore situations identified from the inspections.[34]

The issues that were in contention involve the unit price of each cross-bore inspection, the number inspections, and repair work involving unable-to-access (UTA) locations where physical inspection and repair will instead be required. Both Cal Advocates and TURN argue for a reduced number of inspections, especially for UTA locations, based on historical numbers. On the other hand, PG&E states that it is committed to performing the work and that it can substitute additional non-UTA locations if it cannot complete the 10,000 UTA inspections in San Francisco that it had proposed.

[34] Exhibit 12 at 4-25.

Article 2.3.3.1 of the Settlement Agreement adopts PG&E's proposed costs for the cross-bore program but clarifies that the unit cost for UTA inspections is $2,080 and for non-UTA locations $655. We find this to be reasonable as this funding level allows PG&E to perform close to its planned number of inspections but also addresses uncertainty regarding the number of UTA inspections that cannot be performed. The adopted agreement allows PG&E to conduct additional non-UTA inspections as a substitute for UTA inspections that it cannot perform due to access issues. PG&E will conduct as many UTA inspections in San Francisco as it is able to work in consultation with the City of San Francisco on access issues as provided in Article 2.2.3.2.

Asset Family: Measurement & Control and CNG

PG&E plans to install sulfur filters at all regulator locations within its system to reduce the likelihood of debris and liquids from entering the system and impacting pilot-operated regulators and monitors. This new program aims to prevent large overpressure events due to equipment failure at regulator stations. Cal Advocates originally recommended normalizing costs over a three-year period and recommended around $1.5 million less than PG&E's program cost of around $3.1 million claiming the installation is a one-time expense. Cal Advocates' original recommendation spreads the cost over three years. PG&E argues that Cal Advocates did not correctly calculate individual cost and number of sulfur filter station installations to be made and that additional installations will be made beyond the test year. We agree with PG&E's reasoning and based on the evidence and in light of the settlement agreement to adopt PG&E's forecast, we find no issue in accepting PG&E's forecast for installation of sulfur filters at its regulator stations.

Corrosion Control

Cal Advocates originally objected to two subaccounts under Cathodic Protection associated with the Enhanced Cathodic Protection Survey (ECPS) and casing mitigation of pipelines. Cal Advocates had recommended using more recent costs and normalizing costs for the ECPS which is set to be completed in 2021. However, Cal Advocates' recommendation assumes uniform work throughout the five-year period of the program despite, as stated in PG&E's testimony, the program having experienced delays in the first two years[35] and expenses for the latter three years are expected to be higher. Expenses attributed to the delay approximate Cal Advocates' recommended reduction. The program also addresses a key risk identified in PG&E's RAMP Report and the necessity of the program itself is not in question.

With respect to the Casing Mitigation program, Cal Advocates recommended basing costs on 2017 and 2018 expenditures. However, as PG&E explained, the program began with a developmental phase to determine the most appropriate and cost-effective mitigation measures[36] and so subsequent expenditures are expected to be higher as the program is fully implemented. Based on the above, we find PG&E's forecasts which were adopted by the settling parties, more reasonable.

Gas Operations Technology & Other Distribution Support

Cal Advocates originally recommended approximately $4.5 million less than PG&E's forecast because of an alternative calculation of costs for Operational Management and Operational Support. Because the issue revolves solely around different forecasting methodologies recommended by PG&E and

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35 Exhibit 10 at 7-19.

36 Exhibit 15 at 7-9.

Cal Advocates, we give due consideration to the agreement reached by both parties in the settlement to adopt PG&E's method. In this case, we also find it more prudent not to make any substantive findings regarding the initial differences between PG&E and Cal Advocates. We find no issue in applying the forecast method proposed by PG&E to determine the average cost per employee for both Operational Management and Operational Support.

6.1.11. NERBA and NGLAPBA

PG&E also requests continuation of the NERBA, which tracks the difference between actual and adopted costs related to the 26 best practice activities associated with minimizing methane emissions as adopted by the Commission in the Natural Gas Leak Abatement Order Instituting Rulemaking (Leak Abatement OIR)[37]. PG&E is also requesting to modify the NERBA to retain the distribution subaccount until 2022 for the sole purpose of tracking costs associated with below ground Grade 3 leak repairs.

In Resolution G-3538 issued on October 11, 2018, the Commission stated that it will re-evaluate PG&E's below ground Grade 3 leak repair plan and so PG&E had proposed a placeholder number of 2,000 per year below ground Grade 3 leak repairs for this GRC cycle. Thus, PG&E requests to track the above costs as the number of required repairs will be impacted by the Commission's re-evaluation of the repair plan

PG&E also proposes to close the NGLAPBA which records the difference between actual and authorized costs of R&D related to methane emission

[37] R.15-01-008.

reduction. Pursuant to D.17-06-015[38], PG&E states that the NGLAPBA will no longer be necessary.

Cal Advocates originally proposed that the below ground Grade 3 leak repair costs be recorded in the NGLAPBA but in the settlement agreed to PG&E's proposal. We agree with PG&E that the NGLAPBA tracks R&D costs associated with minimizing methane emissions which is different from what the NERBA tracks. We also find it more appropriate to track the below ground Grade 3 leak repairs in the NERBA because the NERBA tracks costs associated with the 26 best practices adopted by the Commission in the Leak Abatement of OIR. The activity in question relates to compliance with best practice number 21.

In view of the above, we find the proposals to modify the NERBA and eliminate the NGLAPBA, as agreed-upon in the settlement, reasonable and should be adopted.

6.1.12. Summary

Based on the discussions above regarding Gas Distribution O&M costs, we find the settlement forecast for the eight Gas Distribution organizations totaling approximately $369.080 million reasonable and should be adopted. We also find it reasonable to adopt the modification proposed to the NERBA, and the proposal to eliminate the NGLAPBA.

6.2. Capital

The settlement adopts PG&E's forecasts for Gas Distribution capital projects for 2018, 2019, and 2020. The table below shows the total amounts for capital projects adopted in the Settlement Agreement for each of the above years for the eight organizations that comprise Gas Distribution.[39] Pursuant to

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[38] D.17-06-015 is the decision in the Leak Abatement OIR.

[39] The project groupings are shown in Appendix B of the Settlement Agreement at 10 to 14.

Article 3.2 of the Settlement Agreement, the amounts for 2018 capital projects are subject to the adjustment wherein the forecast amounts adopted in the settlement for 2018 are to be updated with recorded capital expenditures in 2018.

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Gas Distribution Capital	2018	2019	2020
Asset Family Distribution and Mains	$562,693,000	$501,891,000	$584,133,000
Asset Family Measurement & Control and CNG	$110,281,000	$131,777,000	$131,105,000
Gas Distribution Operations & Maintenance Programs	$2,091,000	$2,158,000	$1,966,000
Corrosion Control	$20,462,000	$22,322,000	$18,577,000
Leak Management	$44,130,000	$30,888,000	$39,212,000
Gas System Operations	$75,240,000	$72,396,000	$69,479,000
New Business and WRO	$144,565,000	$157,945,000	$162,368,000
Gas Operations Technology & Other Distribution Support	$9,374,000	$13,810,000	$15,164,000
Total	**$968,837,000**	**$933,188,000**	**$1,022,273,000**

6.2.1. Distribution and Mains Capital

Pipeline Replacement Programs

Pipeline Replacement Programs include PG&E's Gas Pipeline Replacement Program, Plastic Replacement Program, and Reliability Main Replacement Program.

Gas Meter Protection

The Gas Meter Protection Program protects exposed meters from vehicular damage. After remediation of the remaining locations that are part of PG&E's commitments from D.89-12-057, the program has transitioned from a dedicated program into ongoing maintenance.

Other Reliability Replacement Programs

Other Reliability Replacement Programs aims at risk-based replacement of facilities other than pipe such as valves. Other programs are the Stubs Program, Deactivation Program, and System Reliability Other Equipment Program.

6.2.2. Measurement & Control and CNG Capital

NGV Station Infrastructure

Natural Gas Vehicles Station Infrastructure includes the Compressed Natural Gas Stations capital program that focuses on replacement of equipment that is obsolete, has outlived its useful service life, or is not in acceptable working condition.

Reliability Projects

Reliability Projects include District Regulator Station Programs which are not high-pressure regulator (HPR) types. These programs allow PG&E to continuously evaluate stations and equipment and identify issues related to obsolescence, condition, and performance. The programs address: (a) Maintenance programs to effectively inspect and maintain equipment; (b) Component replacements for equipment identified as obsolete; and (c) Rebuild facilities to maintain the overall facilities and to address operational and safety needs.

Replace/Convert HPR

Replace/Convert HPR projects include inspection and maintenance of farm tap HPRs[40] and removal or rebuilding of HPR regulation equipment to address gas leaks and equipment condition.

6.2.3. Operations and Maintenance Capital

Install New Gas Meters

[40] A farm tap is an HPR that serves a single service line directly from a transmission pipeline.

This category includes routine replacements of residential and commercial regulators that are made when a PG&E evaluation indicates that the regulator is worn and needs to be replaced. In addition to these routine replacements, PG&E will replace regulators without Internal Relief Valves (IRV) with units that have IRVs.

6.2.4. Corrosion Control Capital

Reliability Projects

Reliability projects under Corrosion Control include the following capital programs: (a) replacing cathodic protection system components and casing mitigation; and (b) installing or replacing impressed current cathodic protection systems

6.2.5. Leak Management Capital

Reliability and Service Replacement Projects

Capital projects included in this category relate to Service and Main replacement work. Increased leak repair work is expected because of the transition from a four to a three-year compliance leak survey cycle and compliance with new requirements for leak repair.

Leak Replacement and Emergency Response Projects

Leak Replacement and Emergency Response Projects of PG&E include: (a) scheduling and replacement work to remediate leaks from inspections; and (b) responding to emergencies by replacing or repairing damaged or failed facilities due to gas dig-ins and external forces such as landslides and earthquakes.

6.2.6. Gas System Operations Capital

Capacity Projects

Capacity Projects include new capacity activities such as adding pipeline and regulator station capacity due to new customers and increased usage of existing customers. To address new distribution system capacity requirements, PG&E plans to install new pipelines, regulators, and regulator station components.

Control Operations Assets

Control Operations Assets (also referred to as SCADA Visibility) projects include projects relating to the following: (a) expansion of system visibility through the installation of field SCADA equipment, and (b) implementation of new customized computerized processes and control systems that enable the operation of the GDCC.

6.2.7. New Business and WRO Capital

Customer Connects

Capital projects for this category consist of installing gas infrastructure required to connect new customers to PG&E's distribution system and to accommodate increased load from existing customers.

WRO Projects

WRO covers capital expenditures for relocating gas distribution and service facilities at the request of a governmental agency or other third parties.

6.2.8. Technology & Other Distribution Support Capital

Tools and Equipment

Projects under this category include the Gas Distribution Capital Tool Program which supports planning, purchase, and deployment of capital tools to field personnel performing operations, construction, and maintenance activities for the gas distribution system. PG&E replaces worn, damaged, or obsolete tools on an ongoing basis and looks for specialized tools to better perform testing and analysis.

Build IT Apps and Infrastructure

Built IT Apps and Infrastructure projects include programs relating to Gas Operations TSP which designs and governs business technology strategy that enables gas operations to identify, plan and prioritize the right work. Specific projects relate to asset management, work management, and real-time monitoring and control capability.

6.2.9. Positions of the Parties

The settlement adopts PG&E's capital forecasts for Gas Distribution.

Cal Advocates recommends adopting 2018 recorded expenditures for all capital projects. Cal Advocates also originally recommended a slower 2019 ramp up of capital projects for Gas Systems Operations and Corrosion Control.

TURN and Cal Advocates originally opposed funding for the overpressure enhancement projects under Asset Family Measurement & Control and CNG.

CUE and OSA objected to PG&E's proposed rate of replacement for pre-1985 plastic pipes.

6.2.10. Discussion

As stated above, the settlement adopts all of PG&E's Gas Distribution capital forecasts. Cal Advocates' recommendation of adopting 2018 recorded expenses for capital projects is addressed by Article 3.2 of the Settlement Agreement which requires PG&E to adjust its RO model by replacing 2018 capital forecasts with recorded 2018 capital costs. Article 3.2 is discussed in greater detail in the Other Adjustments section of the decision.

Parties did not object to PG&E's proposed capital projects for Gas Distribution Operations & Maintenance Programs, Leak Management, New Business and WRO, and Gas Operations Technology and Other Distribution Support. We reviewed the capital projects proposed for these organizations and find the proposed projects reasonable. Most of the projects are routine capital projects that PG&E conducts each year and these types of projects have been authorized by the Commission in prior GRCs.

Capital projects under Gas Distribution Operations & Maintenance Programs are for replacement of regulators in the distribution system. This capital project is regularly conducted to replace residential and commercial regulators when PG&E evaluates that the regulator is worn and needs to be replaced. In addition, PG&E will replace regulators without IRV with units that have IRVs. This is intended to mitigate risk of pressure buildup and to improve safe delivery to customer gas lines and equipment.

Capital projects under Leak Management are for service and main replacements and emergency response work primarily caused by third-party dig-ins. Once again, these are capital projects that are conducted regularly and have been authorized by the Commission in past GRCs. Costs for service and main replacements are expected to be higher than 2017 recorded expenditures because of new requirements for leak repair pursuant to Best Practice 21 in the Leak Abatement OIR and because PG&E will transition from a four-year to a three-year compliance leak survey cycle. Costs for emergency response work are expected to decrease due to the removal of costs for responding to extreme weather events in 2017.

Capital Projects for New Business and WROs also involve routine projects that are regularly performed by PG&E. These projects relate to installing gas infrastructure to connect new customers to PG&E's distribution system and capital expenditures for relocating gas distribution and service facilities at the request of governmental agencies or other third parties. In both instances, costs are usually shared between PG&E and customers or with the requesting entity in cases of relocations.

Costs for Technology & Other Distribution Support Capital projects are forecast to decrease by ranges of around $5 to $8 million in 2018, 2019, and 2020 compared to 2017 capital expenditures because capital expenditures for Manage Buildings is now included under Shared Services, Real Estate capital projects.

Asset Family Distribution and Mains

Pursuant to Article 2.2.2 of the Settlement Agreement, the settling parties agree to a total replacement rate of 417 miles of pre-1985 Aldyl-A and similar plastic pipes and a total cost of $1.231 billion for this GRC cycle. We find that the above agreements represent a fair compromise between PG&E's proposals and objections and concerns raised by CUE and OSA. The agreement addresses the total replacement miles recommended by OSA and CUE but allows PG&E to achieve this objective by ramping up its replacement rate over a three-year cycle.

The settlement also requires PG&E to provide a replacement timeline plan for the above pipes in its next GRC which we find addresses CUE's recommendation to establish a two-way balancing account for PG&E's pipeline replacement programs.

Asset Family Measurement & Control and CNG

Parties do not object to the forecasts for capital projects to add and replace components for regulator stations as well as projects to replace obsolete equipment at CNG stations. We find that these capital projects are projects that PG&E regularly undertakes and take no issue with the proposed forecasts which we find to be supported by the testimony presented.

Cal Advocates and TURN originally proposed elimination of the OPP Enhancements Program for this GRC cycle. This program seeks to improve OPP at Measurement & Control stations and is forecast at around $5.0 million in 2019 and $13.8 million in 2020. Specifically, the project involves the installation of slam shut devices at pilot-operated distribution regulator stations in order to reduce risks of large over-pressure events. This is a new program that is designed to incorporate industry best practices and mitigate equipment-related and incorrect operations threats in an effort to provide secondary overpressure protection. Cal Advocates and TURN originally argued that PG&E has made great advancements in reducing overpressure events and that large overpressure events have decreased since 2011.

However, based on our review, PG&E's Over-Pressure Enhancements Program is designed to address one of PG&E's top enterprise risks identified in its RAMP Report. Measurement & Control Failure – Release of Gas with Ignition Downstream is a key risk identified during the RAMP process and a secondary overpressure device such as a slam shut device provides added protection. The slam shut device is an added measure to mitigate the above risk which can result in loss of containment with ignition. Although these events do not occur with great frequency, potential damage may be catastrophic and installation of secondary overpressure devices is considered an industry best practice. Based on the above, we find that there is sufficient reason to justify this proposed capital project.

Corrosion Control

Cal Advocates noted that expenditures for 2018 of $14.8 million were approximately $6 million less than forecast. For 2019, Cal Advocates recommended a gradual ramp up of projects from 2018 levels as opposed to PG&E's forecast. Cal Advocates recommendation for 2018 is $16.9 million compared to PG&E's forecast of $22.3 million. Cal Advocates did not object to PG&E's forecast for 2020.

PG&E explains that the shortfall in 2018 was due to workforce transition from retirement of key personnel and re-deployment of personnel and resources for wildfire response.[41] Because these conditions are not expected to be repeated in 2019, we find it reasonable to assume that PG&E is capable of meeting its forecast amount of work for 2019. For 2018, we agree with Cal Advocates that actual 2018 capital expenditures should be adopted because PG&E was not able to complete the work that it had forecast. However, we find that this is adequately addressed by Article 3.2 of the Settlement Agreement which requires PG&E to update all of its 2018 capital forecasts with actual 2018 capital expenditures. Based on the above, we find PG&E's capital forecasts for Corrosion Control reasonable, which the settlement adopts.

Gas Systems Operation Capital

In its testimony, Cal Advocates made similar recommendations as it did for Corrosion Control capital: adopt actual 2018 expenditures, apply a gradual ramp up for 2019 projects 2019 based on 2018 levels; and accept the 2020 forecast. Actual expenditures in 2018 were around $5.7 million less than the 2018 forecast and Cal Advocates' recommendation for 2019 is around $5.4 million less than PG&E's forecast.

For 2018 projects, we agree with Cal Advocates' recommendation to adopt 2018 recorded costs but find this to be adequately addressed by Article 3.2 of the Settlement Agreement. For 2019 projects, we agree with PG&E that Cal Advocates' recommendation does not take into account the reason for the lower expenditures in 2018. Developer delays and delayed work impacted projects to install new mains, regulators, and regulator components in 2018. In

[41] Exhibit 168 at 15.

addition, the forecast for these projects are impacted more by demand for new installations as opposed to actual projects completed during the previous year. Thus, we find PG&E's basis for its 2019 forecast more applicable.

For SCADA projects, unit costs are forecast to be higher in 2019 and so we find PG&E's forecast for SCADA projects more reasonable than Cal Advocates' recommendation because it only considers the level of work conducted in 2018 and the level set for 2019 is somewhat arbitrary. We also have no issue with the settling parties' agreement in Article 2.2.4 of the Settlement Agreement that PG&E shall demonstrate the reasonableness of additional SCADA installations if additional installations are proposed in PG&E's next GRC.

Summary

Based on the above discussions, we find it reasonable to adopt PG&E's Gas Distribution capital forecasts for 2018, 2019, and 2020 of $968.837 million, $933.188 million, and $1.022 billion respectively with the understanding that the forecast amount for 2018 will be adjusted pursuant to Article 3.2 of the Settlement Agreement.

7. Electric Distribution

This section addresses PG&E's Electric Distribution O&M, capital and other requests for TY2020. PG&E's electric distribution system is comprised of approximately 106,681 circuit miles of electric distribution lines and 18,466 circuit miles of interconnected transmission lines. PG&E provides electric services through approximately 5.4 million electric customer accounts.

This section also includes programs and activities aimed at reducing wildfire risk through PG&E's Community Wildfire Safety Program (CWSP) as well as programs and activities to modernize PG&E's electric grid and the foundation for an Integrated Grid Platform (IGP) to address evolving distribution resource needs such as integration of distributed energy resources (DER).

In Article 2.3.1 of the Settlement Agreement, the settling parties agree to adopt a forecast of $966.9 million for O&M expenses for TY2020. For capital projects, the settling parties agree to adopt PG&E's forecasts of $1.732 billion for 2018, $1.959 billion for 2019, and $2.233 billion for 2020. Pursuant to Article 3.2 of the settlement, the adopted capital cost for 2018 is subject to the adjustment described in the article wherein the forecast will be updated with recorded capital expenditures for 2018. Said adjustment is discussed in greater detail in the Other Adjustments section of the decision.

7.1. Wildfire Mitigation and CWSP

During its previous GRC cycle (2017 to 2019), PG&E continued its safety and compliance programs in place at the end of 2016 to mitigate wildfire risks. PG&E refers to these as "Control" programs and plans to continue these existing programs. These control programs are listed in the table below:[42]

Control Program	Description
Overhead Patrols and Inspections	PG&E patrols and inspects overhead facilities to identify damaged facilities and other conditions that pose wildfire risks.
Vegetation Management	In compliance with GO 95 and Rule 35, PG&E's vegetation management includes inspection and identification of problematic vegetation, as well as vegetation control, clearing, and removal.
Catastrophic Event Memorandum Account (CEMA)	PG&E's vegetation management associated with prolonged drought conditions.

[42] Exhibit 16 at 9 to 11.

Non-Exempt Equipment Replacement	Replacement of equipment not exempt from PRC 4292 requirements with equipment that is exempt. Exempt equipment is certified by CAL FIRE as having lower fire risk.
Overhead Conductor Replacement	A targeted program that replaces overhead conductor, with work prioritized for high fire risk areas and conductors with high likelihood of failure.
Animal Abatement	PG&E plans to install new equipment and retrofit existing equipment to reduce animal contacts with its equipment.
Protective Equipment	The installation of equipment such as fuses, reclosers, and Supervisory Control and Data Acquisitions (SCADA) that isolates equipment during abnormal operating conditions.
Overhead Equipment Replacement	PG&E will proactively identify and replace critical overhead distribution equipment, such as cross-arms, transformers, capacitors, reclosers, and switches.
Deteriorated Pole Replacement	Inspection work to identify deteriorated wood distribution and transmission poles; Replacement or remediation of deteriorated poles, as appropriate.
Wood Pole Bridging	Installation of a wire that connects the through-bolt of all phases of a distribution wood pole to reduce the probability of a pole fire resulting from current traveling through the wooden cross arms.
Design Standards	The general standards for proper application of equipment to ensure safe and reliable operation.
Restoration, Operational, Procedures and Training	The procedures contained in Utility Standard TD-1464S23 and Utility Bulletin TD-1464B-00124 for increased Wildfire controls when a Fire Index Area has a rating of Very High or Extreme.

During the RAMP process immediately preceding this GRC,[43] PG&E identified six additional "Mitigation" programs to supplement its existing control programs. The Mitigation programs are described below.[44]

Mitigation Program	Description
Wildfire Reclosing Operation Program (SCADA Programming)	The program disables the reclosing operation of circuit breakers and line reclosers during "Very High" and "Extreme" fire risk weather conditions. This program was set to expire in 2019.
Wildfire Reclosing Operation Program (SCADA Capability Upgrades)	This program installs SCADA capabilities for reclosers in extreme fire areas. After SCADA is added, the reclosers are then managed under the Wildfire Reclosing Operation Program.
Fuel Reduction and Powerline Corridor Management	This program reduces vegetation near targeted portions of overhead distribution lines to reduce the frequency and impact of ignitions caused by vegetation.
Overhang Clearing	This program clears vegetation above the overhead electrical distribution lines to reduce the chances of a branch falling on the line.
Non-Exempt Surge Arrestor Replacement	This program will replace non-exempt surge arresters with exempt surge arresters which have been certified by CAL FIRE as lower fire risk.
Targeted Conductor Replacement	This program will replace spans of overhead conductor in high-risk wildfire areas with hybrid tree wire (or covered conductor).

43 PG&E's 2017 RAMP Report was filed on November 2017.

44 Exhibit 16 at 12 to 13.

After the 2017 October wildfires however, PG&E identified more mitigation programs in addition to those identified during the RAMP process and created a CWSP to comprehensively address wildfire risks.

7.1.1. CWSP

The CWSP is an integrated wildfire mitigation strategy that incorporates a risk-based approach to identify and address PG&E's assets that are most at risk from the threat of wildfires and its associated events. Using the CWSP, PG&E will perform wildfire risk assessment and identify wildfire risk mitigation work. The CWSP has five main programs: (a) Enhanced Vegetation Management (EVM); (b) Wildfire System Hardening; (c) Enhanced Operational Practices; (d) Enhanced Situational Awareness; and (e) Other Support Programs.

Funding requests for control programs, mitigation programs, and CWSP represent a significant portion of PG&E's GRC funding request. As shown in Table 2A-10 of Exhibit 16, wildfire prevention and mitigation costs are forecast at approximately $431.477 million in O&M costs and more than $1.3 billion in capital costs from 2018 to 2020.[45]

PG&E's support for the above requests is dispersed throughout different volumes and chapters of its testimony. Majority of CWSP-related requests are found in this chapter and these are reviewed and discussed as they appear under various O&M and capital sections in this chapter.

EVM

EVM is vegetation management work to further reduce wildfire risk performed in addition to PG&E's current Vegetation Management program. Under EVM, PG&E will remove or trim trees belonging to ten tree species that

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[45] Exhibit 16 Table 2A-10 at 2A-51.

have been identified to have caused 75 percent of vegetation ignitions in Tier 2 and Tier 3 High Fire Targeted Districts (HFTD) and have a potential of striking electrical distribution lines. PG&E will also remove all trees or tree limbs above distribution lines in Tier 2 and Tier 3 HFTD to give at least a 4-feet clearance to each side of every conductor. In addition, PG&E will increase vegetation-to-line clearances in Tier 2 and Tier 3 HFTD from 18 inches to 48 inches, as required by D.17-12-024.

Wildfire System Hardening

PG&E's Wildfire System Hardening program is an ongoing long-term capital investment program aimed at reducing the risk of potential ignitions associated with PG&E's facilities and equipment. This program includes the following: (a) replacing primary and secondary conductor with insulated or covered conductor; (b) replacing existing wood poles with coated, non-wood poles that are more resistant to fire and can support the additional weight of insulated conductors; (c) replacing primary line equipment (fuses, cutouts, and switches) and surge arrestors with equipment that CAL FIRE certified as posing lower fire risk and exempt from vegetation clearance requirements; (d) replacing old overhead distribution line transformers with new units filled with fire resistant insulating fluid; (e) upgrading distribution protection systems to handle faults; and (f) converting targeted overhead distribution lines to underground cable.[46] Additionally, PG&E is creating Resilience Zones which are pre-configured segments of the distribution system that can be isolated from and reconnected to the broader grid. These zones are designed to provide temporary power to critical community services during a Public Safety Power Shut Offs

[46] Exhibit 16 at 28.

(PSPS) event and can allow quicker service restoration to areas impacted by PSPS.

Enhanced Operational Practices

Enhanced Operational Practices is PG&E's program to reduce the likelihood of wildfire ignitions caused by its electric system by means of special operational practices that PG&E will perform during elevated fire conditions. Enhanced Operational Practices includes the following programs:

a. Public Safety Power Shut Offs (PSPS) - the PSPS will temporarily suspend electrical service to select electric circuit segments during high fire danger conditions.

b. Reclose Blocking - reclose blocking disables the automatic reclosing functionality of line reclosers and circuit breakers so that a faulted line segment will not be re-energized during high fire danger conditions.

c. Automation and Protection - the program aims to install additional system automation and protection equipment in wildfire areas to support the PSPS and Reclose Blocking programs. For example, PG&E planned to install SCADA in all its equipment with reclosing capability in Tier 2 and Tier 3 HFTD so that it can remotely disable and enable reclosing functionality on the reclosers and circuit breakers in these areas by 2019. Adding automation capability to the grid enables more granular sectionalizing which can reduce the length of line affected by a PSPS or Reclose Blocking event and reduce the areas where power would be shut off.

d. Wildfire and Infrastructure Protection teams - PG&E will prepare 25 crews during higher fire season and 5 crews for an extended fire season throughout its territory.

e. Aviation Resources - PG&E will purchase and operate four additional heavy-lift helicopters, equipping them with fire suppression tools to aid in wildfire suppression. PG&E will also use these helicopters for heavy-lift maintenance and construction work of its infrastructure to enhance wildfire safety.

Enhanced Situational Awareness

Enhanced Situational Awareness includes programs to actively monitor wildfire risks and model potential wildfire occurrences. PG&E established a Wildfire Safety Operations Center (WSOC), which serves as an operational coordination, facilitation, and communication hub for wildfire activities. The WSOC monitors potential fire threats in real time and coordinates with first responders and public safety officials. PG&E uses its SmartMeter system to quickly detect and locate downed power lines. In addition, PG&E plans to install a network of approximately 600 wildfire cameras to visually monitor fire conditions and 1,300 weather stations to provide information about temperature, wind, and atmospheric moisture in Tier 2 and Tier 3 areas. PG&E will also implement a Satellite Fire Detection System to monitor wildfire risks with satellite data. PG&E is increasing its wildfire modeling capabilities by enhancing its existing storm damage prediction model and building advanced fire modeling capabilities into its existing meteorological models.

Other Support Programs

Other Support Programs include a program for employee engagement and training for operational changes related to the CWSP, and a project management office to oversee and coordinate multiple lines of business to implement the CWSP.

Reporting

The settlement also includes reporting requirements specified in Section 2.3.2.3 of the Settlement Agreement.

7.1.2. Wildfire Mitigation Balancing Account (WMBA)

PG&E is also requesting authority to establish a two-way WMBA beginning in 2020 to record CWSP-related expenses. PG&E explains that a two-way balancing account is needed to address the uncertainties surrounding the execution of the CWSP. Costs to be tracked in the WMBA include both O&M and capital costs found in various organizations under Electric Distribution and elsewhere. The request to establish a WMBA is discussed at the end of this chapter.

7.2. O&M

Electric Distribution O&M expenses are for work activities related to operation, supervision, and maintenance associated with the electric distribution system, load dispatching, station expenses, overhead and underground lines, poles, street lighting, customer installations, tree trimming, line transformers, and miscellaneous work.[47] Electric Distribution also includes programs and activities associated with PG&E's CWSP. The CWSP aims to further reduce wildfire risk and among other things, focuses on substantial investments to further harden PG&E's Electric Distribution system and ensure that PG&E is prepared to quickly respond to wildfire events.

As stated above, the settlement adopts a forecast of $966.9 million for TY2020 O&M expenses. By comparison, recorded O&M expenditures in 2017 were $521.183 million and $922.866 million in 2018.[48]

The settlement reduces PG&E's proposed forecast of $1.026 billion by approximately $59.338 million. All the reductions are in the Vegetation Management organization. In addition, $0.461 million in reductions is further applied due to labor escalation adjustments also adopted in the settlement. Generally, the labor escalation adjustments adopted in the settlement are lower

[47] Exhibit 183 at 1.

[48] Exhibit 183 Table 07-2 at 7.

than PG&E's originally proposed escalation rates. In order to simplify and focus discussion on Electric Distribution elements, reasonableness of the labor escalation rates adopted in the Settlement shall not be discussed in this section but shall instead be discussed in the Human Resources section of the decision. Thus, while the settlement amounts incorporate the labor escalation adjustments adopted in the settlement, the discussion concerning Electric Distribution shall only address the unadjusted values. Because there are numerous organizations under Electric Distribution, discussion of each organization's proposed O&M forecast shall be made separately under each organizational heading unlike in other chapters of the decision where all O&M costs are discussed under a single heading.

The table below shows the different organizations that comprise Electric Distribution that have an O&M forecast for TY2020. As stated above, the settling parties agree to adopt PG&E's proposed costs except for Vegetation Management. The table also reflects the total labor escalation adjustments incorporated into the settlement amount.

<table>
<tr><th>Electric Distribution</th><th>PG&E Forecast</th><th>Labor Escalation Reduction</th><th>Settlement Amount</th></tr>
<tr><td>Emergency Preparedness and Response</td><td>$48,762,000</td><td rowspan="10">$59,338,000

Plus

$461,000 labor escalation</td><td rowspan="10">$966,909,000</td></tr>
<tr><td>Electric Emergency Recovery</td><td>$91,140,000</td></tr>
<tr><td>Distribution System Operations</td><td>$43,468,000</td></tr>
<tr><td>Electric Distribution Maintenance</td><td>$83,847,000</td></tr>
<tr><td>Vegetation Management</td><td>$607,392,000</td></tr>
<tr><td>Pole Asset Management</td><td>$13,588,000</td></tr>
<tr><td>Distributed Automation and System Protection</td><td>$2,050,000</td></tr>
<tr><td>Substation Asset Management</td><td>$29,158,000</td></tr>
<tr><td>Electric Distribution Engineering and Planning</td><td>$17,001,000</td></tr>
<tr><td>Electric Distribution Technology</td><td>$4,347,000</td></tr>
</table>

New Business and Work at the Request of Others	$21,503,000		
Electric Distribution Support Activities	$54,274,000		
Integrated Grid Platform & Grid Modernization Plan	$10,178,000		
Total	**$1,026,708,000**	**$59,799,000**	**$966,909,000**

7.2.1. Emergency Preparedness and Response (EP&R)

The EP&R organization is responsible for preparing PG&E to respond to catastrophic incidents such as earthquakes, high wind events, wildfires, drought, flooding, and mudslides. EP&R helps ensure that facilities, logistics, technology, and processes are planned and established prior to a catastrophic event.

PG&E's forecast of $48.762 million includes incremental funding for initiatives included in its CWSP such as establishment of a WSOC,[49] establishment of customer outreach activities for its PSPS protocols, installation of weather stations, enhancement to its Wire Down Detection program, installation of wildfire cameras, and additional staffing and infrastructure protection teams.[50] By comparison, recorded costs in 2017 and 2018 were $4.715 million and $12.118 million respectively.

PG&E states that some of the programs included under EP&R are additional precautionary measures implemented after the wildfires in 2017, intended to further reduce the risk of wildfires. As shown in Table 7-4 of Exhibit 183, base costs for EP&R are forecast at $6.465 million compared to $4.715 million in 2017 and $5.934 million in 2018. In contrast, costs for CWSP initiatives under this organization are forecast at $42.297 million.

[49] Exhibit 16 at 3-1.

[50] Exhibit 183 at 8 to 9.

7.2.1.1. Discussion

The settlement adopts PG&E's forecast less approximately $2,000 representing labor escalation adjustments also adopted by the Settlement Agreement.

Cal Advocates initially recommended adopting PG&E's recorded costs of $12.118 million for TY2020 reasoning that the CWSP initiatives are uncertain and that some of the proposed projects may not be implemented. Cal Advocates also suggested that excess costs be recorded in a one-way balancing account capped at PG&E's requested amount.

FEA makes the same recommendation as Cal Advocates to adopt recorded costs in 2018 for the TY2020 forecast also because of uncertainties surrounding activities under CWSP. Any expense over the authorized amount should be recorded in a memorandum account.

PG&E's forecast includes incremental funding for many new or enhanced initiatives and activities related to its CWSP. These include costs for the WSOC, PSPS community outreach, wildfire detection meteorology projects, wildfire cameras, enhanced wire down detection, and safety and infrastructure teams. The WSOC aims to monitor wildfire risks in real time and coordinate prevention and response efforts with first responders. PSPS-related costs include the establishment of PSPS protocols and community outreach regarding these. Wildfire detection meteorology project costs aims to improve wildfire prediction using computer models and GIS. Wildfire cameras are for the installation of additional cameras throughout PG&E's service territory to improve monitoring and detection. PG&E began installing wildfire cameras in 2018 and plans to install approximately 180 each year in this GRC cycle. Enhanced wire down detection is for enhancement of PG&E's current system. Finally, safety infrastructure team costs are for the additional personnel needed for the increased activities relating to CWSP.

We find the above activities reasonable and necessary measures to enhance PG&E's wildfire mitigation efforts as detailed in its testimony. PG&E also provided support for its cost estimates. In addition, PG&E explained that many of the above activities were just being initiated in 2018 and so comparative expenditures in 2018 for the above activities are significantly less than the forecasts for TY2020.

In addition, PG&E also presents that it will continue other wildfire mitigation efforts such as expanded weather station deployment, advance fire modeling, costs relating to satellite fire detection, and costs relating to storm outage prediction and model automation.

Based on the above, we find the settlement amount more reasonable than the recommendation of utilizing 2018 expenditures as a basis.

With respect to two-way balancing account treatment of costs, this issue is addressed as part of the discussion concerning the proposed WMBA.

7.2.2. Electric Emergency Recovery (EER)

The EER program involves the work in response to routine and major emergencies. This includes responding to incidents and outages during emergencies, performing equipment repairs and replacements related to emergencies, and providing staffing for the Emergency Operations Center (EOC), Regional Emergency Centers (REC) and Operations Emergency Centers (OEC) during major emergencies.[51] PG&E states that the activities under this organization are exclusive from activities conducted under EP&R.

[51] Exhibit 16 at 4-1.

PG&E's forecast for EER is $91.140 million which is $18.5 million less than recorded expenses for 2017 of $109.6 million.[52] EER is divided into two categories, Routine Emergencies and Major Emergencies, and each has corresponding O&M and capital forecasts. The O&M forecast for Routine Emergencies is $57.357 million, while the forecast for Major Emergencies is $33.784 million. PG&E has five incident levels and these are described in pages 4-12 to 4-14 of Exhibit 16. Incidents under level 1 are classified as Routine Emergencies while incidents falling under levels 3 to 5 are classified as Major Emergencies. Level 2 incidents can either be Routine or Major depending on whether an OEC is activated to provide communications or oversight and support.

7.2.2.1. Discussion

The settlement adopts PG&E's forecast less approximately $0.122 million representing labor escalation adjustments also adopted by the Settlement Agreement. Parties do not oppose PG&E's forecast for EER.

We reviewed PG&E's proposed forecast and find it reasonable. Costs under this organization are associated with recurring emergency work that PG&E conducts every year. Additionally, PG&E's forecast is significantly less than 2017 recorded expenditures. However, costs for this organization remain difficult to predict as activities are dependent on the number of emergencies that occur. While PG&E has developed a proactive approach to prepare for emergencies and reduce response times, weather continues to be a major factor that influences the number and severity of emergencies that occur.

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[52] Exhibit 16 at 4-2.

7.2.2.2. Catastrophic Event Memorandum Account (CEMA) and the Major Event Balancing Account (MEBA)

PG&E proposes continuation of CEMA and MEBA.

The CEMA is a memorandum account that records incremental costs when there is a declaration of a state of emergency or disaster from a competent state or federal authority with respect to the event causing the emergency response. PG&E follows the criteria established in Resolution (Res.) E-3238 and Pub. Util. Code § 454.9 to determine whether costs are eligible for CEMA recovery. Res. E-3238 authorizes PG&E to record incremental catastrophic event repair and restoration costs and compliance with governmental orders in connection with declared state and federal disasters. Recovery of incremental costs recorded in the CEMA is made via a separate application outside of this GRC.

On the other hand, the MEBA is a two-way balancing account that records expense and capital costs resulting from responding to Major Emergencies that are not due to CEMA-eligible events and thus cannot be recovered through CEMA. Costs can only be charged to the MEBA if the event meets the criteria of a Major Emergency, as provided in Standard EMER-4510S described in PG&E's testimony.[53] Most major emergencies are directly related to major weather events which vary year-to-year.[54]

Reasonableness of the CEMA and MEBA has already been addressed in PG&E's prior GRC and we make the same findings and conclusions with regards to the continuation of these two accounts. PG&E does not propose to make any changes to the current structure of the CEMA and MEBA and costs recorded in

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53 Exhibit 16 at 4-14.

54 Exhibit 16 at 4-25.

both accounts continue to be dependent on catastrophic or major emergency events that are difficult to predict.

Since 2014 PG&E has funded certain vegetation management expenses through the CEMA.[55] As discussed below in Section 7.2.5.1, the settlement modifies the Vegetation Management Balancing Account (VMBA) to incorporate both routine and enhanced vegetation management costs. We find consolidating similar activities into one balancing account promotes efficiency in tracking and reviewing costs. PG&E does not provide a rationale for the continued separation of one category of vegetation management costs in the CEMA. Rather, beginning in TY 2020, PG&E shall track all vegetation management costs in its VMBA.

7.2.3. Distribution System Operations

PG&E's Distribution System Operations (DSO) organization continuously monitors the electric distribution system, manages outage restoration, and directs system switching.[56] PG&E relies on technology to support the above activities. In addition, DSO also manages electric-related customer service field work.

PG&E's forecast for DSO is $43.468 million and is approximately $7.5 million more than recorded costs in 2017 of $35.9 million. The settlement adopts PG&E's forecast less $71,000 in labor escalation adjustments also adopted by the settlement. The table below shows the forecasts for each MWC under DSO and the amounts adopted in the settlement. Parties did not object to PG&E's TY2020 forecasts.

Distribution Systems Operations	PG&E Forecast	Escalation Reduction	Settlement Amount

[55] Exhibit 16 at 2A-26 to 2A-27.

[56] Exhibit 16 at 5-1.

Electric Distribution Operations Activities	$21,380,000	$36,000	$21,344,000
Customer Field Service Work	$20, 415,000	$34,000	$20,381,000
Operations Technology	$1,673,000	$1,000	$1,672,000
Total	**$43,468,000**	**$71,000**	**$43,397,000**

Electric Distribution Operations

The forecast for Electric Distribution Operations includes costs for activities related to the operation of PG&E's electric distribution grid. SCADA specialists who monitor and program SCADA equipped devices for remote operations were moved to the Distribution Automations and Protection Program to better align with PG&E's organizational structure.

Customer Field Service Work

Customer Field Service Work includes addressing partial and complete outages, transfer of service and service upgrades, temporary disconnections and reconnections, and scheduling and assignment of field and electric customer service work.

Operations Technology

Operations Technology includes expense forecasts for several support activities for DSO. Activities include ongoing SCADA programming support for reclose blocking; Distribution Control Center (DCC) application upgrades, annual software license and vendor maintenance costs for SCADA or other DCC applications, and Fault Location, Isolation and Service Restoration (FLISR) software maintenance.

7.2.3.1. Discussion

The settlement adopts PG&E's TY2020 forecast of $43.468 million less $71,000 in labor escalation adjustments resulting in an adopted amount of $43.397 million. Parties do not object to PG&E's forecast although it is approximately $7.5 million higher than recorded expenditures in 2017. In chapter 5 of Exhibit 16, PG&E explains that the higher costs are due to escalation, re-assignment of personnel for scheduling and dispatching and directing safe response to outages and 911 calls, support for implementation and operation of reclose blocking wildfire risk mitigation, and O&M costs for a capital project relating to critical operating equipment. We find the settlement forecast reasonable and that PG&E's uncontested testimony supports and sufficiently explains the increased costs compared to 2017 expenditures for this organization.

7.2.4. Electric Distribution Maintenance (EDM)

Electric Distribution Maintenance (EDM) is responsible for routine maintenance of PG&E's electric distribution facilities. PG&E's EDM Program requires rigorous inspection of facilities and timely corrective maintenance. PG&E's distribution system includes approximately 81,000 miles of electric overhead distribution lines and approximately 26,000 miles of electric underground distribution lines. These lines are equipped with many different electric distribution assets which require routine inspection and maintenance.

According to PG&E, it historically patrols, on average, 1.2 million overhead and 247,000 underground locations, performs detailed inspections of 450,000 overhead and 143,000 underground locations, and performs 24,000 equipment inspections every year.[57] These patrols and inspections generate corrective maintenance notifications that identify facilities in need of replacement or repair.

PG&E's forecast for EDM is $83.847 million which is approximately $11.1 million higher than recorded costs of $72.7 million in 2017. The settlement

[57] Exhibit 16 at 6-1.

adopts PG&E's TY2020 forecast for EDM less approximately $90,000 in labor escalation adjustments also adopted by the settlement.

The table below shows the forecasts for each MWC under EER and the amounts adopted in the settlement. Parties do not object to PG&E's TY2020 forecasts.

Electric Distribution Maintenance	PG&E Forecast	Escalation Reduction	Settlement Amount
Patrols and Inspections	$33,124,000	$40,000	$33,084,000
Distribution Line Equipment Overhauls	$1,664,000	$2,000	$1,662,000
Overhead Preventive Maintenance and Equipment Repair	$32,482,000	$33,000	$32,449,000
Underground Preventive maintenance and Equipment Repair	$12,547,000	$10,000	$12,537,000
Network Preventive Maintenance and Equipment Repair	$4,030,000	$5,000	$4,025,000
Total	**$83,847,000**	**$90,000**	**$83,757,000**

Patrols and Inspections

Patrol and Inspections include expenses for routine patrols and inspections of PG&E's overhead and underground facilities. These are conducted to identify conditions that impact regulatory, safety, and reliability compliance. Patrols and Inspections also include activities related to infrared inspections of overhead equipment. These are conducted system-wide in select areas at high risk of wildfire in order to identify failed conductor splices and faulty switches.

Distribution Line Equipment Overhauls

Distribution Line Equipment Overhauls include repair of specialized distribution line equipment such as transformers, voltage regulators, reclosers, capacitor banks, and line switches.

Overhead Preventive Maintenance and Equipment Repair

Overhead Preventive Maintenance and Equipment Repair are for expenses relating to overhead notifications, overhead critical operating equipment, streetlight burnout replacement, and idle facilities investigation and removal.

Underground Preventive Maintenance and Equipment Repair

Underground Preventive Maintenance and Equipment Repair costs are for underground preventive maintenance which includes creation of the Underground Notification Program. This program is designed to improve reliability, improve safety, and ensure regulatory compliance by correcting abnormal maintenance conditions in PG&E's underground facilities.

Network Preventive Maintenance and Equipment Repair

Network Preventive Maintenance and Equipment Repair costs include inspection and oil sampling of all major oil-filled network components of transformers, inspection and testing of network protectors, maintenance of SCADA, and electric corrective notification work in network vaults.

7.2.4.1. Discussion

The settlement adopts PG&E's TY2020 forecast of $83.847 million less $90,000 in labor escalation adjustments resulting in a settlement amount of $83.757 million. Parties did not oppose PG&E's original forecast. The settlement amount is approximately $11 million higher than 2017 recorded expenditures.

As discussed above, costs supported by this organization relate to expenses concerning work to patrol, inspect, and maintain PG&E's Electric Distribution systems. FEA recommended $1.6 million less than PG&E's forecast and is the only party that opposed PG&E's original forecast. FEA recommended using a four-year average from 2015 to 2018 stating that EDM costs have been fluctuating. However, as explained by PG&E in its rebuttal testimony,[58] its EDM forecasts were developed using program specific factors and we find this more appropriate in this instance as it addresses the projected needs for this GRC cycle as opposed to simply relying on historical averages. PG&E also explains that the forecast takes into account expanded patrol, inspection, and maintenance activities to further mitigate wildfire risk. Thus, we find the settlement amount to be reasonable and should be authorized. Reasonableness of the labor escalation adjustments are explained in the Human Resources chapter of this decision.

7.2.5. Vegetation Management

PG&E's Vegetation Management (VM) program patrols trees along high voltage distribution lines, pre-inspects trees for scheduled maintenance and clearance as required for regulatory compliance, prunes or removes vegetation from around poles that have the potential to cause fires, and maintains or removes "hazard trees" or trees that it identifies as structurally unsound.[59]

PG&E's forecast for TY2020 is $607.4 million and is approximately $405.9 million higher than recorded expenses of $201.5 million in 2017. The above includes activities that fall under the existing VM program forecast at $229.3 million as well as activities that fall under PG&E's enhanced VM program which is forecast at $378.1 million. Routine VM includes cost to patrol, inspect, and maintain clearance for trees along high voltage distribution lines. It also includes routine tree pruning and removal, contractor quality control, environmental compliance, public education, and fire risk reduction work.

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[58] Exhibit 20 at 6-7.

[59] Exhibit 183 at 16.

On the other hand, enhanced VM includes work intended to reduce wildfire risk in Tier 2 and Tier 3 HFTDs. This includes work on the following:

a. Overhang Clearing: includes removing branches overhanging electric power lines to further reduce possibility of wildfire ignitions and/or downed wires due to vegetation- conductor contact.
b. Targeted Tree Species Work: includes identifying and pruning or removing specific tree species adjacent to power lines that may have a higher potential to fail during wildfire.
c. Fuel Reduction: involves reducing vegetative fuels in the area under and adjacent to power lines with the intention of further reducing wildfire risk.
d. Light Detection and Ranging: this activity helps with the mitigation of risk resulting from tree growth, tree failure and or tree mortality.

Enhanced VM work began in 2018 and so there were no enhanced VM expenses recorded for 2017. Costs for routine VM are currently recorded in the existing VMBA while costs falling under enhanced VM are proposed to be included in the WMBA.

In addition, PG&E is requesting incremental funding for maintenance work related to the ongoing Enhanced VM work for the PTYs. The funding requested is an additional $71.9 million for 2021 and $42.4 million for 2022. These amounts are significantly higher than ordinary escalation that would apply to PTY costs.

PG&E also requests that the incremental inspection and removal cost tracking account procedure established in D.07-03-044 during the 2007 GRC be discontinued as PG&E has not sought any cost recovery through the above procedure.

7.2.5.1. VM Provisions in Settlement

In Article 2.3.3 of the Settlement Agreement, the settling parties combine the amounts forecast for both routine and enhanced VM and agree to adopt the following amounts:

2020: $548.013 million

2021: $602.814 million

2022: $663.096 million

The 2020 amount is approximately $59.338 million less than PG&E's original request for TY2020 inclusive of a reduction of around $41,000 in labor escalation adjustments incorporated in the settlement amount. Reasonableness of the labor escalation adjustment is discussed in the Human Resources chapter.

The incremental funding 2021 is less than the incremental funding originally requested by PG&E while the 2022 increment is close to the same increment originally requested by PG&E.

The settlement also proposes to modify the one-way VMBA to become a two-way balancing account which would incorporate both routine and enhanced VM costs. The settlement also includes several provisions concerning reasonableness review for VMBA undercollection, compliance with D.19-05-037 regarding removal of healthy trees, tracking and reporting of VM work, and a targeted tree species study as proposed by TURN. In addition, the settlement also proposes to eliminate the Incremental Inspection and Removal Cost Tracking Account (IIRCTA) which is a VMBA sub account associated with incremental inspection and tree removal.

7.2.5.2. Positions of the Parties

Cal Advocates and TURN originally proposed significant reductions of approximately $71.7 million and $170.0 million respectively to PG&E's forecast for enhanced VM. FEA also opposes PG&E's forecast for enhanced VM and in addition recommends a reduction of $0.742 million to PG&E's forecast for routine VM.

7.2.5.3. Discussion

As stated above, PG&E's request for VM is comprised of $229.3 million for routine VM and $378.1 million for enhanced VM.

Routine VM consists of work already being performed by PG&E. This includes costs to patrol, inspect, and maintain clearance for trees along high voltage distribution lines. This also includes routine tree pruning and removal, contractor quality control, environmental compliance, public education, and fire risk reduction work. This kind of work has already been reviewed in PG&E's prior GRC and found to be necessary and reasonable work to aid in wildfire mitigation efforts. Routine VM work also complies with General Order 95, Rules 35 and 37, and §4292 and 4293 of the California Public Resources Code.[60]

Other than FEA's recommended reduction of $0.742 million, parties generally did not contest the forecast for routine VM which is higher than recorded expenditures of $201.456 million in 2017 but lower than recorded expenditures in 2018 of $260.460 million. FEA asserts that this amount can be recovered from telecommunications companies for a portion of the cost to mitigate tree hazards where PG&E and telecommunications companies share facilities. However, PG&E explains that the above amounts collected from telecommunications companies are already credited back to customers via the WMBA.[61] Based on the above, we find PG&E's forecast for routine VM

[60] Exhibit 20 at 7-6.

[61] Exhibit 20 at 7-7.

reasonable, especially because costs fall within the range of costs previously incurred for these activities that are being performed regularly by PG&E.

For enhanced VM, PG&E's forecast of $378.1 million is around $70 million higher than recorded costs in 2018 of $308.2 million.[62] There were no enhanced VM activities during the base year. Most of the costs for enhanced VM relate to overhang clearing ($147.7 million) and targeted tree species work ($186.0 million).

Although we consider the general scope of work that PG&E has planned as important in mitigating wildfire risks, we share the concerns raised by Cal Advocates, TURN, and FEA that PG&E's forecast is ambitious, has an undefined scope of work, and an unpredictable pace of work. PG&E does not have historical expenses for enhanced VM and we agree with Cal Advocates that 2018 recorded expenses are a good representation of future costs because the programs and projects included in enhanced VM are the same. 2018 is also the only year where enhanced VM has been performed and so there are no other years that can be used as historical reference of programs and projects and costs.

The settling parties agree to a $59.338 million reduction from PG&E's forecast for both VM and enhanced VM. Although the settling parties do not specify, we find that the above reduction to PG&E's forecast adopted by the Settlement Agreement can be attributed as a reduction to PG&E's forecast for enhanced VM as parties were in agreement with PG&E's forecast for routine VM.

If attributed to the forecast for enhanced VM alone, the reduction to PG&E's forecast results in an enhanced VM forecast of $318.8 million compared

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[62] This is the amount currently recorded in the FHPMA per the 2nd errata correction to the FHPMA balance.

to the requested amount of $378.1 million. This amount is much closer to recorded expenditures for enhanced VM in 2018 of $306.412 million.

Concerns that the proposed settlement amount may be inadequate to address needed VM work to further reduce the risk of wildfires is addressed in the discussion concerning the proposed two-way VMBA.

Based on our analysis of the various forecasts from parties, recorded costs in 2018, and the fact that most of the projects and programs for enhanced VM proposed in the TY are substantially the same as those performed in 2018, we find that the settlement amount of $548.013 million for VM and enhanced VM represents a fair compromise between party positions. The settlement amount takes into account recorded expenditures as well as concerns that PG&E's forecast is, as PG&E itself admits, somewhat ambitious as well as lacking in detail with regards to scope and pace of work. We also find the PTY amounts agreed upon for routine and enhanced VM work reasonable given that enhanced VM work is expected to ramp-up as the program becomes more fully developed. The recent wildfires from 2018 onwards also indicate that incremental mitigation activities are needed to further mitigate wildfire risk.

7.2.5.4. VMBA

The settlement proposes to modify PG&E's current one-way VMBA that records routine VM expenses into a two-way balancing account that will record both routine and enhanced VM spending. Originally, costs for enhanced VM were proposed to be recorded in the WMBA.

First, we agree with tracking both routine and enhanced VM costs into a single balancing account. This promotes efficiency as the activities conducted are similar. Enhanced VM activities are relatively new and over time, we believe that the distinction between routine and enhanced VM activities will disappear and all such activities will merely be referred to as VM activities.

With respect to the proposed two-way treatment of costs, we agree with this approach in light of the settlement reduction of more than $59 million to VM activities discussed in the preceding section. As stated in the preceding section, the enhanced VM program is new and so a proper forecast that balances both affordability and necessary work that needs to be performed is difficult to determine. In addition, the scope of activities continues to be refined but we find that a more conservative estimate for VM costs is more prudent at this point given the other incremental activities being proposed under PG&E's CWSP. However, because of enhanced wildfire risk, we find that it may be necessary for PG&E to conduct additional VM activities that are difficult to predict at this time. A two-way balancing account will enable PG&E to act with less delay in case further mitigation activities and additional costs above the authorized level become necessary to mitigate wildfire risk. At the same time, the two-way treatment of costs allows PG&E to return excess funds not utilized to ratepayers.

Article 2.3.4.2 contains provisions regarding review of costs exceeding 120 percent of the authorized funding level for VM, revenue requirement true-up, and return of overcollections. We agree with these provisions except that we find it prudent to modify these provisions such that VM undercollections that exceed 130 percent of the authorized funding should be filed as an application. This allows enhanced review of large cost recovery amounts.

We also agree with the provisions concerning VM tracking, reporting, and targeted tree species study provided in Articles 2.3.4.4 to 2.3.4.6 of the Settlement Agreement as well as the provision to eliminate the Incremental Inspection and Removal Cost Tracking Account (IIRCTA) as provided in Article 2.3.4.1. The

IIRCTA is a VMBA sub-account associated with incremental inspection and tree removal. The additional provisions regarding VM render this sub account as unnecessary. We are also in agreement that PG&E comply with Ordering Paragraph 7 of D.19-05-037, which states that PG&E shall only remove healthy trees if it has evidence that those trees pose a risk to utility electric facilities under wildfire ignition conditions, based on the opinion of a certified arborist.[63]

7.2.6. Pole Asset Management

Pole Asset Management includes: (a) intrusive inspections of wood poles which involve excavating the ground-line of poles and boring access holes in the pole to assess the presence and extent of decay or deterioration; (b) reinforcement of wood poles as needed; and (c) coordination with other utilities who use the poles.

7.2.6.1. Discussion

Parties do not object to PG&E's forecast of $13.588 million for TY2020. The settlement adopts PG&E's forecast less $3,000 in labor escalation adjustments also adopted in the settlement. We find this amount reasonable and supported by the evidence. PG&E proposes to continue activities relating to pole inspection, maintenance, and restoration that were already being conducted in its prior GRC. In addition, the settlement amount does not deviate greatly from recorded expenses of $12.3 million in 2017 and the increase of around 10 percent from 2017 recorded expenses can be attributed to escalation of labor and other costs from 2017 to 2020. The settling parties also agree that PG&E will maintain data for each pole replaced that includes the reason for each replacement and will develop a means to report this rationale, including information as to

[63] D.19-05-037 OP 7.

whether a pole loading calculation was performed and the results of the calculation for supporting covered conductors.

7.2.7. Distribution Automation & System Protection

The Distribution Automation & System Protection (DAP) program covers the installation, upgrade, and replacement of remotely controlled automation and protection equipment in both distribution substations and on feeder circuits. The forecast expenses will provide engineering support for automation and protection equipment.

7.2.7.1. Discussion

The adopts PG&E's forecast of $2.050 million for TY2020 less $2,000 in labor escalation adjustments also adopted in the settlement. The adopted amount is approximately $0.5 million higher than recorded costs of $1.6 million.

We find the proposed amount reasonable and supported by the evidence presented. The adopted amount of $2.048 million does not differ greatly from recorded 2017 expenses of $1.6 million and the increase can be attributed to escalation of labor and other costs from 2017 to 2020. The work performed under DAP improves operating efficiency, enables better outage response and diagnosis, improves system protection, and provides wildfire risk management. In addition, the work forecast under this section will also improve employee and public safety by enabling PG&E to automatically and remotely shut off electricity during emergencies and remotely disable the operation of reclosers in high fire risk areas. Parties do not object to the forecast for DAP activities.

7.2.8. Substation Asset Management

PG&E's Substation Asset Management organization is responsible for managing the repairs and maintenance of equipment located in approximately 760 electric distribution substations. The equipment includes power transformers, circuit breakers, switchgears, protective relays, bus structures, and voltage regulation equipment.[64] The three general categories of expense activities are: (a) Preventive Maintenance; (b) Corrective Maintenance; and (c) Substation Support Activities.

PG&E's forecast of $29.158 million is approximately $2.6 million higher than recorded costs of $26.568 million in 2017. The settlement adopts PG&E's forecast less $33,000 in labor escalation adjustments also adopted in the settlement resulting in a $29.125 million forecast for TY2020.

7.2.8.1. Discussion

As stated above, the settlement adopts PG&E's forecast less $33,000 in labor escalation adjustments resulting in an adopted amount of $29.125 million. Cal Advocates originally recommended adopting recorded expenses in 2018 of $26.958 million. Cal Advocates explained that maintenance and repair costs for substations have been stable for the past five years and that PG&E's projected increase is not justified. Cal Advocates also states that there are no new maintenance programs or projects to support the increase.

However, in PG&E's rebuttal testimony, PG&E explains that the forecast does include O&M funding for new programs such as the six Major Emergency Corrective Maintenance programs that will be completed in 2018 and 2019. Therefore, O&M expenditures for these completed programs are expected to be incurred in 2020. PG&E also describes the activities that are driving the cost increases such as increases in the number of Load Tap Changer overhaul inspections and transformer oil diagnostic tests, increases in unit costs under Corrective Maintenance, and net increase in Substation Support Activities. The

[64] Exhibit 183 at 25.

remainder of the forecast was based on work that has been regularly conducted in previous years. Thus, we find the settlement amount reasonable and supported by the evidence.

7.2.9. Electric Distribution Engineering & Planning

The Engineering and Planning Program supports a variety of asset management and operating activities and its responsibilities include planning, designing, and operating PG&E's electric distribution system.[65] The program also supports performing diagnostics on data and automated field equipment to support distribution control centers. The program also investigates secondary voltage complaints that PG&E "Troublemen[66]" cannot resolve on a first visit.

PG&E's forecast of $17.001 million is approximately $4.178 million higher than recorded costs of $12.823 million in 2017. The settlement adopts PG&E's forecast less $27,000 in labor escalation adjustments resulting in $16.974 million. PG&E explains that the increase in costs is primarily due to the ramp-up in 2018 of the Asset Performance Center (APC).

7.2.9.1. Discussion

Cal Advocates is the only party that had originally objected to PG&E's proposed costs. Cal Advocates stated that costs for PG&E's APC contained lump sum requests that are not substantiated and that historical costs do not support PG&E's forecast. Cal Advocates recommended a forecast of $13.990 million which is approximately $3.0 million less than PG&E's.

Electric Distribution Engineering and Planning costs primarily cover labor expenses that support a variety of asset management activities. One of the

[65] Exhibit 16 at 14-1.

[66] A PG&E Troubleman is a first responder that determines if the service voltage complies with Electric Rule No. 2. PG&E is required to provide electric service under Electric Rule No. 2.

programs under this organization is the APC, which performs diagnostics on data from automated field equipment to support PG&E's distribution control centers.[67] Cal Advocates' initial recommendation prior to the settlement was to authorize only one-third of the funding requested for the APC. Cal Advocates did not object to the other forecasts for Engineering and Planning. From our review, PG&E provided a cost estimate worksheet with working formulas to show forecasted costs for the APC.[68] The cost estimate also shows projected costs for each of the APC's three main functions which are (a) operation and monitoring of APC data systems; (b) development work to transition R&D pilot efforts into operations systems; and (c) data analytics to support LOBs. Based on the above, we find that the APC costs were sufficiently explained and thus conclude that the amounts adopted by the settlement for Electric Distribution Engineering & Planning are reasonable and supported by the evidence presented in the proceeding.

7.2.10. Electric Distribution Technology

Electric Distribution Technology involves costs for investments in new technology which according to PG&E is necessary to keep pace with customer demands, to meet regulatory mandates, to mitigate risks, and to provide PG&E employees with efficient and effective tools.

One of these programs is the DAP program, which is focused on the installation, upgrade, and replacement of remotely controlled automation and protection equipment in substations and on feeder circuits. The DAP program is

[67] Exhibit 20 at 14-1.

[68] Exhibit 20 at 14-6.

intended to improve efficiency and outage response, and build a platform for FLISR technology deployment.

PG&E's forecast for O&M costs for TY2020 is $4.347 million which the settlement adopts minus $2,000 for labor escalation adjustments also adopted by the settlement. PG&E's forecast is approximately $1.7 million less than recorded costs of $6.1 million in 2017.

7.2.10.1. Discussion

We find the amount of $4.345 million adopted by the Settlement Agreement reasonable and necessary. These costs correspond to the O&M portion of capital projects and support ongoing maintenance, operations and repair for PG&E's IT applications, systems and infrastructure. The proposed costs are less than recorded expenses in 2017 and relate to activities that are ordinarily conducted each year. Parties also do not oppose PG&E's forecast and the amount adopted in the Settlement Agreement.

7.2.11. New Business and WRO

New Business involves activities relating to the installation of electric infrastructure required to connect new customers to PG&E's distribution system and to accommodate increased load from existing customers. On the other hand, WRO activities relate to the relocation of PG&E's existing electric facilities at the request of customers and governmental agencies. This includes undergrounding of existing overhead electric facilities.

As shown in the table below, the settlement adopts PG&E's forecasts minus the amounts pertaining to labor escalation adjustments that were also adopted in the settlement. PG&E's forecast is approximately $7.3 million higher than recorded costs of $14.2 million in 2017.

New Business and WRO	PG&E Forecast	Escalation Reduction	Settlement Amount
Manage Services Inquiries	$12,626,000	$1,000	$12,625,000
WRO Maintenance	$8,877,000	$18,000	$8,859,000
Total	**$21,503,000**	**$19,000**	**$21,484,000**

Manage Service Inquiries

Manage Service Inquiries includes activities associated with processing customer applications for new gas and electric services and coordinating requests from existing customers for additional load and revisions to existing services.

WRO Maintenance

WRO Maintenance covers costs relating to electric WRO expense work required by tariffs and franchise agreements. This includes non-plant relocations, alterations of electric facilities, and third-party Electric Grid Interconnection (EGI) activities.

7.2.11.1. Discussion

FEA and JCCA object to PG&E's proposed costs. FEA states that PG&E has underspent authorized costs in prior years and recommends $2.5 million less than PG&E's forecast of $12.626 million. FEA's recommended amount is based on 2017 and 2018 recorded expenditures. In its rebuttal testimony, PG&E explains how application fees authorized by the Commission in 2016 for Electric Grid Interconnection (EGI) were reflected as credits in 2017 and 2018 which offset spending related to EGI. However, beginning in 2019, the EGI credits would have been zeroed-out thus leading to higher expenditures than in 2017 and 2018 where EGI application fees were reflected as credits.[69]

[69] Exhibit 20 at 16-5 to 16-6.

JCCA recommends that allocation of costs or Managing Services should include Electric Generation and not just Gas Distribution and Electric Distribution. However, we find that there is insufficient evidence to show that activities related to Manage Service Inquiries impact Electric Generation as activities appear to impact requests regarding electric and gas service. Specifically, the work involves processing applications for new gas and electric customers, coordinating requests from existing customers for additional load, and re-arrangements of existing services.

Based on the above discussion, we find the settlement's adoption of PG&E's forecast for New Business and WRO costs reasonable.

7.2.12. Electric Distribution Support Activities

This department provides resources and staffing to assist PG&E's Electric Operations business units with managing various programs and projects.

PG&E's forecast of approximately $54.274 million is significantly higher than recorded expenses in 2017 of $22.788 million. PG&E explains that the scope of activities included under this organization has changed significantly since 2017.[70] One of the major changes is that certain overheads currently charged to PG&E's CEMA are instead included in the GRC. By comparison, recorded costs in 2018 are $46.804 million.

The table below shows PG&E's forecasts which are adopted by the Settlement Agreement less small reductions attributed to labor escalation adjustments also adopted by the settlement.

Electric Distribution Support Activities	PG&E Forecast	Escalation Reduction	Settlement Amount
Miscellaneous Expense	$17,717,000	$0	$17,717,000

[70] Exhibit 16 at 18-1 to 18-2.

Mapping	$5,903,000	$4,000	$5,899,000
Streetlight Support	$1,088,000	$0	$1,088,000
Operational Management	$7,228,000	$11,000	$7,217,000
Operational Support	$22,338,000	$33,000	$22,305,000
Total	**$54,274,000**	**$48,000**	**$54,226,000**

Miscellaneous Expense

The forecast for Miscellaneous Expense includes costs for the following: (a) distribution support; (b) applied technology services; (c) inter-departmental energy usage; (d) CWSP management office; e) Electric Data Response Unit; f) paid time off, indirect labor, and material overheads; and g) public awareness outreach.

Mapping

This organization covers costs for PG&E's Electric Distribution Mapping work and Field Asset Inventory project.

Streetlight Support

The forecast for Streetlight Support is for streetlight billing costs. Activities include field inventory audits to verify billing and ownership of streetlights.

Operational Management

Operational Management represents costs to supervise, support, and manage PG&E personnel who charge their time directly to work orders.

Operational Support

Operational Support reflects costs of organizations that support the enablement and execution of field work.

7.2.12.1. Discussion

The settlement adopts PG&E's forecast less $48,000 in labor escalation adjustments resulting in an amount of $54.226 million. Cal Advocates originally recommended close to $5.2 million less than PG&E's forecast stating that certain activities under Miscellaneous Expense and Mapping are routine activities instead of incremental and that costs are already embedded in rates.

Specifically, for Miscellaneous Expense, Cal Advocates recommended zero funding for the Electric Data Response Unit (ERDU) as opposed to the $2.4 million requested by PG&E. ERDU was originally created to coordinate responses to inquiries related to the October 2017 Wildfires. Previously, these activities were performed by various departments and so Cal Advocates' argument is that costs are already embedded in rates. We reviewed the testimony presented and find that the ERDU was created to coordinate responses to these types of activities. Although the type of activity itself is routine, the volume of the activity has significantly increased in recent years which we find provides sufficient justification, in this GRC cycle at least, that portions of the activities are incremental in nature. In addition, the ERDU's scope has been broadened to ensure a coordinated process across the Electric Operations organization to provide accurate responses to an increasing volume of external data requests.

For Mapping, Cal Advocates initially recommended $2.8 million less than PG&E's forecast based on historical spending for the Field Asset Inventory (FAI) project.

The FAI project involves performing a detailed field inventory of the electric distribution overhead system to correct any discrepancies or gaps in PG&E's asset information. According to PG&E, the project will allow it to have complete records of actual field assets and asset records on its systems such as

SAP and GIS databases.[71] We find in PG&E's testimony that a slower ramp-up of this project was experienced in prior years due to vendor delays. PG&E has since replaced the vendor but the transition to a new vendor contributed to more delays. However, PG&E expects activity levels planned for 2018 and beyond to catch up to the intended level.

We also reviewed proposed costs for the other MWCs under this organization and find them reasonable.

FEA recommends using a four-year average from 2015 to 2018 resulting in a reduction of approximately $12.5 million from PG&E's forecast. However, we agree with PG&E that this method does not take into account incremental costs for necessary activities as well as increased volume and scope for activities that were already being performed in prior years.

Based on the discussions above, we find the settlement amount for Electric Distribution Support Activities reasonable and supported by the evidence.

7.2.13. IGP and Grid Modernization Plan

PG&E's Integrated Grid Platform Program (IGP) and Grid Modernization Plan manages PG&E's electric distribution operating technology projects, which includes various system and infrastructure investments, upgrades and enhancements such as SCADA and communications network associated with modernizing its electric grid.[72] PG&E's forecast is $10.178 million compared to $0.469 million in recorded expenses during 2017. Recorded expenses in 2018 are $2.865 million.

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71 Exhibit 20 at 18-7 to 18-8.

72 Exhibit 183 at 45.

The settlement adopts PG&E's forecast less $2,000 in labor escalation adjustments also adopted by the settlement. Most of the costs fall under the Operations, Engineering and Technology MWC as reflected in the table below.

IGP and Grid Modernization Plan	PG&E Forecast	Escalation Reduction	Settlement Amount
Operations, Engineering and Technology	$9,276,000	$1,000	$9,275,000
Information Technology Expense	$902,000	$1,000	$901,000
Total	**$10,178,000**	**$2,000**	**$10,176,000**

Operations, Engineering and Technology

The forecast for Operations, Engineering and Technology covers O&M expenses for capital projects relating to technological enhancements such as the Advanced Distribution Management System (ADMS) project, SCADA replacement asset data enhancement, Wildfire Reclosing Operational Program, DCC application upgrades, Legacy SCADA upgrade and contract support and FLISR system maintenance.

Information Technology Expense

Information Technology Expense includes costs for ongoing maintenance, operations, and repair of PG&E IT applications, systems, and infrastructure.

7.2.13.1. Discussion

Majority of the O&M costs requested under this organization reflect O&M costs for capital projects requested to enhance PG&E's IGP program and Grid Modernization Plan. The requested projects are discussed in the capital portion of this section. As such, reasonableness of the proposed costs is dependent on the reasonableness of the underlying capital projects requested.

Costs are significantly higher than recorded expenditures in 2017 because most of the projects were expected to be finished in 2018 and 2019, hence the related O&M costs with respect to these projects were not incurred in 2017. Similarly, recorded costs in 2018 are significantly lower than the adopted forecast.

7.2.14. O&M Summary

As discussed in the O&M sections above, we find it reasonable to adopt the settlement forecast of $966.909 million for Electric Distribution O&M costs for TY2020. We also find it reasonable to modify the proposed VMBA such that recovery of costs in excess of 130 percent of the authorized amount for VM shall be made by application instead of a Tier 3 advice letter.

7.3. Capital

The settlement adopts PG&E's forecasts for Electric Distribution capital projects for 2018, 2019, and 2020. The table below shows the total amounts for capital projects adopted in the Settlement Agreement for the organizations under Electric Distribution that have capital expenditures for 2018, 2019, and 2020.[73] Pursuant to Article 3.2 of the Settlement Agreement, the amounts for 2018 capital projects are subject to the adjustment wherein the forecast amounts adopted in the settlement for 2018 are to be updated with recorded capital expenditures in 2018.

Electric Distribution Capital	2018	2019	2020
Emergency Preparedness and Response	$9,816,000	$9,181,000	$11,687,000
Electric Emergency Recovery	$228,013,000	$234,843,000	$240,999,000
Distribution System Operations	$3,578,000	$1,073,000	$328,000
Electric Distribution Maintenance	$277,179,000	$277,530,000	$270,903,000
Pole Asset Management	$175,647,000	$109,273,000	$109,365,000

[73] The capital project groupings are shown in Appendix B of the Settlement Agreement at 10 to 14. There is a $2,000 difference in the 2019 and 2020 totals compared to the sum of the individual amounts for each organization due to rounding.

Distribution Overhead System Hardening and Reliability	$89,291,000	$301,824,000	$580,807,000
Distributed Automation and System Protection	$53,277,000	$62,700,000	$34,184,000
Underground Asset Management	$90,807,000	$96,115,000	$99,742,000
Substation Asset Management	$140,874,000	$131,068,000	$123,368,000
Electric Distribution Capacity	$100,243,000	$113,521,000	$125,721,000
Electric Distribution Technology	$15,240,000	$9,941,000	$13,650,000
New Business and Work at the Request of Others	$521,022,000	$559,127,000	$577,820,000
Rule 20A	$54,113,000	$45,098,000	$33,756,000
Electric Distribution Support Activities	($40,065,000)	($31,231,000)	($29,523,000)
Integrated Grid Platform & Grid Modernization Plan	$12,515,000	$38,509,000	$41,053,000
Total	**$1,731,550,000**	**$1,958,574,000**	**$2,233,862,000**

Recorded 2018 Costs

Article 3.2 of the Settlement Agreement provides that 2018 capital costs shall be based on PG&E's recorded capital costs for 2018. However, the settlement adopts PG&E's 2018 capital forecasts. As discussed more thoroughly in the Other Adjustments section of the decision (Chapter 15), Article 3.2 requires PG&E to update its RO model to replace the 2018 capital forecast amounts specified in various sections of the Settlement Agreement with recorded 2018 capital amounts. We also conclude in the Other Adjustments section that we find it reasonable in this GRC for PG&E to replace its 2018 capital forecasts with 2018 recorded expenditures and that doing so does not impair PG&E's ability to provide safe and reliable services to its customers. Based on the foregoing, discussion of the capital forecasts for each of the organizations under Electric Distribution shall be for the capital forecasts for 2019 and 2020.

7.3.1. Emergency Preparedness and Response Capital

7.3.1.1. Emergency Miscellaneous Projects

Projects under EP&R include CWSP initiatives such as establishment of a WSOC in San Francisco, expanded weather station deployment, advanced fire modeling, and enhanced wire down detection. Other projects are technology base camp improvements to permit communication during catastrophes, early earthquake warning, and the project to build an emergency information sharing platform.

7.3.1.2. Discussion

The settlement adopts PG&E's forecasts for 2019 and 2020. Cal Advocates originally recommended zero funding for CWSP projects which equates to reductions of $10.5 million to PG&E's 2020 forecast and $7.0 million to PG&E's 2019 forecast. Instead, Cal Advocates recommended that expenditures for CWSP projects be recorded in either a memorandum account or a one-way balancing account due to the uncertainties associated with these projects and the probability that the projects will not be undertaken and completed as PG&E forecasts.

We reviewed the proposed projects under EP&R and find the CWSP-related projects are necessary in order to further mitigate against wildfire risk. We also disagree with Cal Advocates that the CWSP-related projects under EP&R are uncertain. For example, PG&E shows that around 200 weather stations were actually constructed in 2018. This shows that there is a reasonable degree of certainty that the planned weather stations for 2019 and 2020 may also be constructed. The same analogy can be made with the other planned capital projects based on spending in 2018. Cal Advocates' recommendation to record CWSP-related costs in a memorandum account or a one-way balancing account shall be addressed at the end of this chapter in our discussion of the requested WMBA.

Based on our review, we find it reasonable to adopt PG&E's 2019 and 2020 capital forecasts under EP&R which the settlement also adopts.

7.3.2. Electric Emergency Recovery Capital

7.3.2.1. Emergency Projects

The table below shows the forecasts for Electric Emergency Recovery projects for 2018, 2019, and 2020.

Electric Emergency Recovery Capital	2018	2019	2020
Routine Emergency Projects	$179,241,000	$180,625,000	$185,360,000
Major Emergency Projects	$48,772,000	$54,218,000	$55,639,000
Total	**$228,013,000**	**$234,843,000**	**$240,999,000**

Routine Emergency Projects

Projects include facility replacements in response to overhead or underground outages that occur during normal conditions.

Major Emergency Projects

Project under this category include facility replacements performed during emergency conditions when a division OEC has been activated.

7.3.2.2. Discussion

As previously mentioned, the settlement adopts PG&E's forecasts for 2019 and 2020. Cal Advocates previously recommended reductions of $34.6 million and $35.2 million from PG&E's proposed forecasts for Routine Emergency Projects for 2020 and 2019, respectively. Cal Advocates' recommendation is based on applying a five-year average of capital expenses as opposed to the three-year average relied on by PG&E. Cal Advocates also stressed that a three-year average gives too much weight to 2017 expenditures, which are significantly higher than other years. Cal Advocates adds that increased spending in preventive maintenance and vegetation management will reduce EP&R costs. For Major Emergency Projects, Cal Advocates initially recommended a reduction of $6.6 million each to PG&E's 2020 and 2019 capital forecasts based also on increased spending for preventive maintenance and vegetation management.

PG&E uses a five-year average for forecasting Major Emergency Projects because these are less predictable. For Routine Emergency Projects, PG&E uses a three-year average to better reflect recent trends and current costs. From our review, we find that recent wildfires from 2017 onwards has increased in scale and that it is reasonable to forecast increased work and projects relating to EP&R despite the improvements planned for preventive maintenance and vegetation management. We also find it appropriate to apply a three-year average for Routine Emergency Projects as this better reflects current trends, conditions, and costs especially taking into account the recent wildfires that have impacted PG&E's service territory. Thus, we find it reasonable to adopt PG&E's 2020 and 2019 capital forecasts for EER.

7.3.3. Distribution System Operations Capital

Electric Operations Control Center Facility

Capital projects include ongoing capital improvements and enhancements to PG&E's DCCs and the Fresno Dispatch Facility. This includes technology and needed systems for the above facilities.

7.3.3.1. Discussion

No party opposes the proposed projects under this organization which we reviewed and find reasonable. Thus, we have no issue with the settlement's adoption of PG&E's 2019 and 2020 capital forecasts. In Article 2.3.6.2 of the

Settlement Agreement, parties agree to reduce PG&E's 2020 revenue requirement by approximately $0.5 million each year to account for unit shortfalls for FLISR and cable installations. We find the reduction reasonable as well as the procedure for calculating and applying the reduction as described in Article 2.3.6.2. The reduction is reflected in the RO chapter as a tax repair deduction.

7.3.4. Electric Distribution Maintenance Capital

7.3.4.1. Preventive Maintenance Projects

Projects under EDM are for preventive maintenance such as replacing deteriorated facilities on a planned basis in cases where repair is not cost effective. The table below shows how projects are grouped together as well as the forecasts for each.

Electric Distribution Maintenance Capital	2018	2019	2020
Overhead Electric Distribution Preventive Maintenance	$197,060,000	$198,593,000	$193,646,000
Underground Electric Distribution Preventive Maintenance	$59,356,000	$60,256,000	$57,803,000
Network Electric Distribution Maintenance	$20,763,000	$18,681,000	$19,454,000
Total	**$277,179,000**	**$277,530,000**	**$270,903,000**

Overhead Electric Distribution Preventive Maintenance

Typical equipment replacements include corroded transformers, deteriorated cross arms, inoperative line switches, and other overhead distribution facilities. Projects also include replacement and repair of overhead notifications, corrective maintenance of equipment such as fuses, reclosers, etc., replacing non-decorative High-Pressure Sodium Vapor streetlights with LED streetlights, investigation and removal of idle facilities, and replacement of ceramic pole insulators.

Underground Electric Distribution Preventive Maintenance

Typical equipment replacements include corroded transformers, inoperative switches, damages underground enclosures, and other underground distribution facilities.

Network Electric Distribution Preventive Maintenance

Typical equipment replacements include corroded network transformers, protectors, relay replacements, inoperative switches, and other network distribution facilities. Capital projects also include network SCADA safety monitoring, and the network manhole cover program which replaces existing solid and grated manhole covers on vaults with hinged venting manhole covers designed to stay in place in the event of a vault explosion.

7.3.4.2. Discussion

The settlement adopts PG&E's forecasts for 2019 and 2020. TURN and Cal Advocates originally recommended around $50 million less than PG&E's forecasts for Overhead Preventive Maintenance for both years. The reductions are with respect to the funding for the Surge Arrester Replacement and Non-Exempt Equipment Replacement programs.

PG&E installed surge arresters and distribution transformers using shared ground wire and ground rods or common grounding. These were later deemed deficient pursuant to General Order 95. The Surge Arrester Replacement program aims to fix this defective grounding and also replace non-exempt surge arresters. On the other hand, the Non-Exempt Equipment Replacement program aims to replace non-exempt distribution line equipment with equipment that is exempt from vegetation clearing requirements of section 4292 of the Public Resources Code. Said section requires PG&E to maintain a firebreak within a certain radius from a utility pole.

Cal Advocates recommended that funding levels for these two programs be at around the funding levels authorized in 2017 but with escalation added. For reference, recorded capital expenditures for the two programs are around $84 million less than the 2019 and 2020 forecasts. On the other hand, TURN recommended that PG&E fix the common grounding issue for surge arresters at a reduced level and recommended disallowance of the replacement of non-exempt surge arresters. TURN also stated that PG&E is partly responsible for the defective grounding and so must share in the costs to fix the defect.

From the testimony presented, the Surge Arrester Replacement program combines the grounding of defective surge arresters with replacement of non-exempt surge arresters. There is no question that the grounding work is necessary pursuant to GO-95. However, parties had argued that the replacement of non-exempt surge arresters is not mandatory and not one of the top risks identified in PG&E's 2017 RAMP Report. PG&E argues that since it is already conducting the grounding work, then it makes sense to also conduct the non-exempt replacement work since work crews are already performing the grounding work at the same sites.

We find that both arguments have merit. While not identified as a top risk, replacement of non-exempt surge arresters serves to mitigate fire risk in HFTD and also non-HFTD areas. In this case, we find it prudent to give due regard to the agreement reached by the settling parties to adopt PG&E's proposed capital forecasts for EDM for 2019 and 2020 as the settling parties include both TURN and Cal Advocates. Although the two parties had different recommendations, these parties agreed to adopt PG&E's EDM forecasts as part of the settlement process which includes agreements and concessions from the settling parties. We believe that negotiations were conducted fairly as indicated in the settlement and so give due regard to the settling parties being able to resolve differences.

As for TURN's recommendation to reduce costs because PG&E was partly responsible for the defect, we note that this issue was addressed in PG&E's prior GRC. As for Cal Advocates' initial recommendation to adopt 2017 expenditures, we note that the Surge Arrestor Replacement program includes capitalized expense work pertaining to the portion of the program to replace non-exempt surge arresters. Regarding, the Non-exempt Replacement program, we find that this is necessary to maintain a firebreak from utility poles pursuant to section 4292 of the Public Resources Code.

Parties did not object to the forecasts for Underground and Network Preventive Maintenance, which we reviewed and find reasonable. The programs for these involve typical replacements of corroded transformers, inoperative switches, relay replacements, and other equipment in underground distribution facilities and network distribution facilities. These types of replacements are ordinarily conducted by PG&E and similar programs have been approved in prior GRCs.

In view of the above, we find it reasonable to adopt the amounts proposed in the settlement for EDM capital forecasts.

7.3.5. Pole Asset Management Capital

Installation or Replacement of Overhead Poles

Capital projects under Pole Asset Management relate to the replacement of poles. Ninety-nine percent of replaced poles are wooden poles and these are being replaced to support safety and reliability of the electric distribution system.

7.3.5.1. Discussion

CUE initially recommended an accelerated pace for PG&E's Pole Replacement Program. However, PG&E's updated work plan includes 21,000 additional pole replacements (2020 to 2022) in addition to its original forecast of approximately 24,000 poles for that same period without a change in the proposed costs. PG&E also states that it is tracking and reporting pole replacements annually[74] and that this information is included in PG&E's spending and accountability report that is submitted to the Commission annually. We find that the above updates to PG&E's work plan addresses the concerns raised by CUE concerning more pole replacements and achieving a steady state of replacements. Parties have no objections to the proposed capital costs for 2019 and 2020 which we find reasonable and supported by the testimony presented. PG&E's proposed costs and planned rate of pole replacements are relatively consistent for this GRC cycle.

7.3.6. Distribution Overhead System Hardening & Reliability

7.3.6.1. System Hardening & Reliability Projects

The table below shows the forecasts for System Hardening and Reliability projects.

Distribution Overhead System Hardening and Reliability	2018	2019	2020
Replacement of Overhead Asset	$55,293,000	$253,005,000	$545,050,000
Distribution Circuit/Zone Reliability	$33,998,000	$48,819,000	$35,757,000
Total	**$89,291,000**	**$301,824,000**	**$580,807,000**

Replacement of Overhead Asset

[74] Exhibit 20 at 8-5 to 8-6.

This program includes three subprograms: (a) the Overhead Conductor Replacement Program which addresses deteriorating conductors; (b) the Overhead System Hardening Program which rebuilds vulnerable parts of PG&E's overhead electric distribution system; and (c) the Overhead Switch Replacement Program which replaces obsolete switches to minimize potential safety issues.

Distribution Circuit/Zone Reliability

Projects under this category relate to reliability improvements. These CWSP programs include resilience zones, sectionalizing via installation of additional line reclosers, the Base Reliability program which reviews electrical outages, the Overhead Protection program which is for installation of overhead protective devices, the FLISR program, which uses remotely operable switches along with sophisticated software, and other reliability work such as line recloser control replacements, targeted circuit programs, etc.

7.3.6.2. Discussion

The projects under this section address safety, resiliency, and overall distribution system reliability performance and reliability-related issues. PG&E ordinarily conducted these kinds of capital projects in prior GRCs. However, the programs have been expanded in 2019 and 2020 to include investments in the overhead distribution system to reduce risk of wildfire ignitions and circuit damage in the event of a wildfire. The expanded budget under this section are primarily due to a new Overhead System Hardening Program for Tier 2 and Tier 3 HFTDs. On the other hand, projects under Distribution Circuit/Zone Reliability have been slightly reduced as a result.

As stated above, forecasted expenditures for the Overhead System Hardening project are significantly larger due to plans to expand the program to include large scale wildfire mitigation. The proposals are supported by increased public and employee safety and particularly by added wildfire mitigation.

Generally, intervenors do not object to the expanded spending forecast for wildfire mitigation but argued for less forecasted spending than what PG&E proposed. Cal Advocates and TURN initially questioned PG&E's ability to carry out the programs proposed based on historical data. Cal Advocates had recommended zero funding for the project and stated that expenditures should instead be tracked in a memorandum account. TURN did not support replacement of poles or transformers as part of system hardening. TURN also recommended recording expenditures in a one-way balancing account.

FEA, a non-settling party, recommends using a four-year average of historical expenses. Alternatively, FEA supports Cal Advocates' position of tracking expenditures in a memorandum account. On the other hand, CUE recommended increased funding for Replacement of Overhead Assets project.

Regarding FEA's proposal, we find that historical data is not appropriate in this instance because of the expanded program to include large scale wildfire mitigation and needs to increase proactive replacements and system hardening.

PG&E reduced its original 2020 forecasts totaling $817.039 million to $580.807 million in part because of comments from parties. PG&E shifted some of its forecasted costs from the 2018 to 2020 cycle to the 2020 to 2022 cycle. PG&E also lengthened its time window target for system hardening from 10 to 14 years. In addition, PG&E shifted some of the system hardening budget towards undergrounding projects. PG&E also addresses TURN's objection to replacing poles by citing changing pole standards for HFTDs and increased conductor diameter and weight.

The Settlement Agreement adopts PG&E's adjusted forecasts for 2019 and 2020 which we find reasonable. We find that PG&E's concession of reducing its requested amount for 2020 by around $236 million balances the concerns raised by various parties and the need for expanded system hardening measures and programs for added wildfire mitigation and employee and public safety. Intervenors generally do not object to the need to expand PG&E's system hardening programs but expressed concerns about PG&E's ability to conduct the work being proposed. We find that the adjusted forecast reasonably addresses these concerns.

In addition, the settlement also adopts revenue requirement true-ups, reasonableness thresholds, reporting, and other requirements affecting overhead system hardening through CWSP guidelines. These are discussed in the CWSP section and in the discussion concerning the WMBA.

Specific to system hardening, PG&E is required to provide an annual report of the number of circuit miles completed for both overhead system hardening and undergrounding, the location of the work performed, and the cost of the work broken down by project.[75] To address TURN's concerns that PG&E has over-forecast the number of poles it will need to replace as part of the overhead system hardening, PG&E will maintain data regarding the reason for every pole replaced and will develop a means to report on this data. PG&E will also indicate whether a pole-loading calculation was performed for the pole and provide, upon request, the results of such calculation with respect to supporting covered conductor.

[75] Settlement Agreement Section 2.3.2.3.1.

Based on our discussion above, we find the settlement amounts adopted for 2019 and 2020 for System Hardening and Reliability Projects reasonable and should be adopted. Two-way balancing account treatment of Overhead System Hardening projects are included in the discussion regarding the WMBA.

7.3.7. Distribution Automation & System Protection Capital

Electric Distribution Automation and Protection

Capital projects are to install new substation and line automation equipment to replace obsolete equipment and deficient protective relays. Specific projects include installation and replacement of distribution line SCADA, substation SCADA, replacement of substation protective relays, and miscellaneous emergency SCADA equipment.

7.3.7.1. Discussion

Parties do not oppose PG&E's capital forecasts for 2019 and 2020, which the settlement adopts. The proposed projects mostly involve distribution lines, relays, substations, and equipment related to SCADA. Most of the proposed projects are routine maintenance and upgrades and replacement of obsolete equipment relating to PG&E's SCADA system. We find these to be necessary and projects that PG&E ordinarily conducts during a GRC cycle. Thus, we find it reasonable to adopt the proposed forecasts agreed-upon in the settlement.

7.3.8. Underground Asset Management Capital

Electric Distribution Underground Asset Replacement

Capital projects include reliability cable replacement, cable rejuvenation and testing to evaluate its operating condition, critical operating equipment replacement, systematic replacement of network cable assets and installation of switches, and replacement of load break oil rotary (LBOR)[76] switches.

7.3.8.1. Discussion

Parties do not object to the proposed forecasts for the above projects consisting of cable replacement projects, cable rejuvenation testing, and various types of switch replacements except as discussed below. The settlement adopts PG&E's capital forecasts for 2019 and 2020, which we find reasonable. Projects conducted under this organization are also performed regularly.

OSA recommended establishment of a dedicated program to inspect and remove certain types of antiquated oil-filled switches installed as early as the 1940s.[77] However, we agree with PG&E that a dedicated program is not necessary at this time as PG&E schedules replacement of these switches whenever it discovers these types of switches through its regular inspections. From the evidence, it appears that there are not many of these switches left and replacement of these switches as they are discovered in the course of standard switch inspections that PG&E already performs can be viewed as reasonable prioritization in light of the many other high priority risk reduction programs being authorized in this GRC. If more of these types of switches are discovered with some degree of frequency or in large quantities, then OSA can revisit the need for a dedicated inspection program to locate and replace these switches.

OSA also initially recommended a replacement rate of 676 LBOR switches compared to PG&E's annual replacement rate of 65 switches with a cost of $6.6

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[76] Load Break Oil Rotary is a type of switch. This switch is filled with oil and manually operated. The switch is designed for use with distribution transformers and self-contained distribution switchgear.

[77] Exhibit 20 at 11-6.

million per year. OSA's recommended rate of replacement would require an additional $61.1 million and is approximately ten times the replacement rate that PG&E recommends. While we agree that these oil-filled LBOR switches need to be replaced at some point, we agree with PG&E that this need should be balanced with other priorities. Comparing the two recommendations, we find that PG&E's replacement rate is more reasonable than what was recommended by OSA. In its next GRC, PG&E should submit testimony on whether its annual replacement rate is still viable or whether the rate of replacement needs to be increased. The settlement also contains provisions regarding the replacement of oil-filled switches which we agree with.

7.3.9. Substation Asset Management Capital

7.3.9.1. Substation Asset Management Projects

Capital projects under PG&E's Substation Asset Management are for maintenance and replacement of substation assets. The table below shows the project groupings and the forecasts for each.

Substation Asset Management Capital	2018	2019	2020
Distribution Substation Replace Equipment	$90,492,000	$79,737,000	$49,903,000
Distribution Substation Transformer Replacements	$5,811,000	$2,186,000	$5,568,000
Distribution Substation Safety and Security	$4,571,000	$5,746,000	$4,656,000
Distribution Substation Emergency Equipment Replacement	$40,000,000	$43,399,000	$63,241,000
Total	**$140,874,000**	**$131,068,000**	**$123,368,000**

Distribution Substation Replace Equipment

Projects under this sub-grouping are for replacement of various substation equipment. Specific projects include replacement of switchgears, circuit breakers, switches, insulators, substation structures, and batteries. Projects also include replacement of animal mitigation measures, various support activities, and replacement of other related equipment.

Distribution Substation Transformer Replacements

Projects in this subgroup include proactive replacement of substation transformers and maintaining an adequate supply of emergency transformer inventory and mobile transformers.

Distribution Substation Safety and Security

Projects in this subgroup relate to capital projects that promote safety, security, fire protection, and seismic protection. These include replacement or upgrade of substation fences, short-term environmental work in substations, security cameras and card readers, fire suppression systems, and seismic retrofits to control buildings.

Distribution Substation Emergency Equipment Replacement

Projects under this subgroup are for replacement of equipment that has failed in service and replacement of equipment intentionally removed from service. The latter occurs when equipment is forced out of service when imminent failure is predicted to minimize potential for a sustained outage or catastrophic failure.

7.3.9.2. Discussion

We reviewed PG&E's proposed forecasts for 2019 and 2020 and find them reasonable and supported by the evidence. The proposed projects relate to substation work, which includes replacement of various equipment, transformers, and emergency equipment. Other projects relate to safety and security of the substation location and perimeter. We find that these types of projects are routinely conducted by PG&E and have been authorized in prior

GRCs. Parties do not object to PG&E's forecasts which the settlement adopts. The settlement also contains provisions regarding the replacement of transformers which we do not object to.

7.3.10. Electric Distribution Capacity Capital

7.3.10.1. Capacity Projects

The table below shows the forecasts for capital projects under Electric Distribution Capacity.

Electric Distribution Capacity Capital	2018	2019	2020
Distribution Substation Capacity	$20,056,000	$23,741,000	$35,148,000
Distribution Line Capacity	$80,187,000	$89,780,000	$91,705,000
Total	**$100,243,000**	**$113,521,000**	**$126,853,000**

Distribution Substation Capacity

Distribution Substation Capacity projects relate to upgrades of various distribution substation equipment that are forecast to have a capacity deficiency. Capital projects address normal capacity deficiency, emergency and operational deficiency, and new business-related capacity needs. Projects also include land purchase, purchase of new substations, and support transmission projects.

Distribution Line Capacity

Projects under Distribution Line Capacity include capacity expansion projects outside of substations. Projects address specific capacity deficiencies or overload conditions as well as voltage conditions. Specific projects include feeder projects associated with substation work, projects relating to overloaded line transformers, circuit reinforcements, and voltage projects involving secondary distribution.

7.3.10.2. Discussion

TURN originally recommended zero funding for operational capacity projects designed to reduce customer count and customer load on certain heavily loaded circuits. TURN states that there are no reliability, capacity or voltage incidents or customer complaints to justify these projects. However, the projects are designed to increase distribution capacity in order to maintain customer load on a feeder at a maximum of 6,000 customers.[78] Thus, even if there are no current issues, the programs are designed to prevent issues from occurring as the number of customers increase. We find this proactive approach reasonable and helps ensure that there is sufficient capacity for the electric distribution system especially in times where load is unusually high such as during extreme weather conditions. We also give due regard to the agreement reached by the settling parties, which include TURN.

TURN also recommended no funding for the Power Factor Management Program. The program is designed to install SCADA to certain capacitor controls to enable greater flexibility and remote control of voltage in the system. Similarly, TURN stated that there are no voltage complaints that necessitate this project. We reviewed the scope of the proposed project and find it reasonable. Remote access to capacitor banks provides greater flexibility to make setting changes and eliminates the need for field visits. It also increases operational flexibility during planned and emergency switching and improves the overall reliability of voltage throughout the system. TURN also objects to the installation of SCADA to voltage regulators for the same reasons. Based on our review, we again find this project reasonable for similar reasons to those stated in

[78] Exhibit 20 at 13-9.

our discussion regarding the Power Factor Management Program. The program will also enable two-way power flow in order to facilitate interconnection by DER customers.[79]

7.3.11. Electric Distribution Technology Capital

Electric Distribution Technology projects primarily support asset and work management functions of the Electric Distribution organization.

Asset management projects include map-based field information and real-time asset situational awareness, optimization of planning, upkeep, and replacement of assets, grid interconnection compliance requirements, and customer needs.

On the other hand, work management projects include work planning, engineering and design to improve planning and scheduling capabilities through the unification and standardization of tools, improvement of work execution through increased integration and digitalization of tools and processes, and improvement of emergency preparedness and response to safely, quickly and transparently meet the needs of the communities by leveraging technology and communication infrastructure.

7.3.11.1. Discussion

We reviewed PG&E's proposed forecasts for 2019 and 2020 and find them reasonable and supported by the evidence. The proposed projects involve technology upgrades and enhancements to support asset and work management functions described above. As shown in figure 15-2 of Exhibit 17,[80] capital forecasts for 2018 to 2020 are significantly lower than recorded expenditures in 2017 by approximately $6.0 million or more due to prioritizing capital projects in

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[79] Exhibit 20 at 13-12.

[80] Exhibit 17 at 15-9.

other areas. Parties do not object to PG&E's forecasts for 2019 and 2020 which the Settlement Agreement adopts.

7.3.12. New Business and WROs Capital

The table below shows the capital forecasts for New Business and WROs.

New Business and WROS Capital	2018	2019	2020
Electric New Business	$407,716,000	$442,018,000	$455,093,000
Electric Work at the Request of Others	$113,306,000	$117,109,000	$122,727,000
Total	**$521,022,000**	**$559,127,000**	**$577,820,000**

7.3.12.1. New Business Projects

Capital projects relate to the installation of electric infrastructure required to connect new customers to PG&E's distribution system and to accommodate increased load from existing customers. These include residential and non-residential connections as well as added load for plug-in electric vehicles and transformer purchases and scrapping.

7.3.12.2. WRO Projects

Capital projects relating to WROs cover capital expenditures relating to undergrounding, existing overhead electric facilities, work performed at the request of government entities, developers and customers, state infrastructure projects, etc.

7.3.12.3. Discussion

FEA recommends using 2018 recorded expenditures for PG&E's 2020 forecast for New Business and WROs. FEA's recommendation is based on the historical trend of using the last recorded year whenever costs trend up or down. However, PG&E's forecast was developed based on a number of economic and government spending indices as well as historical PG&E unit cost data,[81] whereas FEA solely utilized historical expenditures for a single year as a basis. Although PG&E admits that it occasionally applies the method that FEA utilized, in this instance, projected costs were based on more applicable data which we find more reliable in this instance.

Cal Advocates originally recommended a total of around $48 million and $53 million less than PG&E's forecasts for 2019 and 2020, respectively. This is based on recommended reductions in the forecasts for new residential and non-residential connections, added load for electric plug-in vehicles, government WROs, and state infrastructure projects. We reviewed the forecasts for the above projects as well as the arguments presented and give due regard to the agreement reached by the settling parties. Cal Advocates agreed to adopt PG&E's forecasts notwithstanding its initial recommendations. In addition, Cal Advocates' original recommendation for new connections assumes that the number of new connections for both residential and non-residential connections will not increase from 2018 levels. The same is true for plug-in electric vehicles, which assumes no growth from 2018 levels. For government WROs, PG&E's expenditures in 2018 are lower than the forecast. However, Cal Advocates' initial recommendation does not consider that expenditures in New Business WRO are higher than the forecast, which partially offsets the lower expenditures for government WROs. Lastly, for state infrastructure projects, Cal Advocates believed that work relating to the high-speed rail project will be scaled back. However, PG&E states that its forecasts relating to high-speed rail considers the current scope and schedule of the project. Based on the above, we find it

[81] Exhibit 20 at 16-10.

reasonable to accept PG&E's 2019 and 2020 forecasts for New Business and WRO projects adopted by the settlement.

The CPUC's undergrounding rulemaking (R.17-05-010) considers revisions to Rule 20 programs. This proceeding remains open and may have ramifications on the annual capital expenditures for Rule 20B and 20C programs. A decision in R.17-05-010 that impacts PG&E's Rule 20B and 20C programs during this GRC cycle may supersede related funding authorized in this decision.

7.3.13. Rule 20A

Capital projects under Rule 20A relate to the conversion of existing overhead electric distribution facilities to underground facilities. In order to qualify for ratepaying funding, a conversion project needs to meet specific public interest criteria such as whether the project will avoid or eliminate unusually heavy concentration of overhead electric facilities, whether the street or road or right-of-way is extensively used by the general public, and whether the street, road, or right-of-way adjoins civic or public recreation areas.

7.3.13.1. Discussion

PG&E's Rule 20A Program allows governmental agencies to underground existing overhead electric facilities if their projects meet specific criteria. The settlement adopts PG&E's adjusted forecasts for 2019 and 2020. PG&E reduced its forecasts for both 2019 and 2020 by $17.2 million and $12.9 million to $45.098 million and $33.756 million respectively, following recommendations by Cal Advocates. The reductions are based on the average annual amount by which PG&E has underspent its authorized Rule 20A funding during the 10-year period of 2009 through 2018 which Cal Advocates calculated as 27.60 percent.[82]

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[82] Exhibit 20 at 17-6.

We find no issue regarding the agreed-upon amounts and find that PG&E shall have sufficient funding to support Rule 20A projects in this GRC cycle. We also give due consideration to the agreement reached by the settling parties regarding funding for Rule 20A projects. In addition, we have no issue regarding the agreement in Section 2.3.5 of the settlement to maintain the annual Rule 20A work credit allocation at the currently authorized level of $43.1 million per year.

As is the case with Rule 20B and Rule 20C programs, a decision in R.17-05-010 that impacts PG&E's Rule 20A programs during this GRC cycle may supersede related funding authorized in this decision.

7.3.13.2. Rule 20A Balancing Account

The settlement retains PG&E's currently authorized Rule 20A balancing account. We find it reasonable to continue authorization of PG&E's one-way Rule 20A balancing account with plans to spend down the account without any modifications. Parties do not object to continued authorization of this account and authorization to continue the Rule 20A balancing account allows PG&E to comply with D.17-05-013.

7.3.14. Electric Distribution Support Activities

Projects under this organization are for capital tools and equipment and miscellaneous capital. The table below shows the forecasts for 2018, 2019, and 2020.

Electric Distribution Support Activities Capital	2018	2019	2020
Tools and Equipment	$7,330,000	$7,722,000	$7,466,000
Miscellaneous Capital	($47,395,000)	($38,953,000)	($36,989,000)
Total	**($40,065,000)**	**($31,231,000)**	**($29,523,000)**

Tools and Equipment

Capital projects consist of the purchase or replacement of general tools and test equipment, applied technology services tools, and capital tools and equipment for applied technology services in testing laboratories.

Miscellaneous Capital

Costs under Miscellaneous Capital represent deductions from PG&E's capital forecasts. These include savings from CWSP management offices capital, paid time off, indirect labor, and material burden overheads (beginning in 2020, this cost will no longer be allocated in the balancing account), and affordability savings led by initiatives in Electric Operations.

7.3.14.1. Discussion

Parties do not object to the forecasts for capital tools and equipment and miscellaneous capital reductions. Purchase of capital tools and equipment to replace general tools and for applied technology services is a routine activity regularly conducted by PG&E. For Miscellaneous Capital reductions, as explained above, these are due to savings from different organizations. The settlement adopts PG&E's forecasts, which we reviewed and find reasonable.

7.3.15. Integrated Grid Platform & Grid Modernization Plan

7.3.15.1. IGP and Grid Modernization Projects

Electric Distribution Operations Technology

Electric Distribution Operations Technology projects relate to deployment and integration of a new ADMS and improvement of Distribution Asset GIS Data.

Information Technology Capital

Information Technology Capital relates to development of distribution planning tool enhancements, new interconnection tools, and to support development of asset data improvement.

The table below provides the forecasts for the above projects.

Integrated Grid Platform & Grid Modernization Plan	2018	2019	2020
Electric Distribution Operations Technology	$12,515,000	$33,479,000	$36,957,000
Information Technology Capital	$0	$5,030,000	$4,096,000
Total	**$12,515,000**	**$38,509,000**	**$41,053,000**

7.3.15.2. Discussion

TURN and Cal Advocates originally opposed PG&E's proposed funding for specific projects under Electric Distribution Operations. FEA also recommends reduced funding for the ADMS project and all O&M funding for the EGI and Distribution Engineering Tools projects. TURN originally opposed all funding for the ADMS project as well as all projects under IGP IT Infrastructure and Network Technologies. Cal Advocates originally recommended reduced funding for ADMS, Distribution GIS Asset Data Improvement, the Field Area Network projects, and the IGP Cybersecurity project.

FEA agrees with Cal Advocates' initial position that the ADMS project funding should be reduced. PG&E provided testimony concerning the scope of the ADMS project, which aims to provide an integrated control center application with added functionality compared to PG&E's existing systems. PG&E also explains that comparing ADMS expenditures costs in the prior GRC is highly inaccurate as expenditures in the prior GRC were prepared assuming that ADMS integration would begin in 2019. This means that approximately 96 percent of ADMS costs were forecast to be incurred in this GRC cycle.

Regarding O&M funding for EGI and the Distribution Engineering Tools project, FEA recommended using recorded expenditures in 2018. However, the expense funding for the above projects is zero because both projects were anticipated to be completed in 2019. FEA does not specifically oppose the two projects, so we find that PG&E's expense forecast is more reasonable as it includes O&M funding for the two projects that are anticipated to be completed prior to the TY.

Regarding the original objections by Cal Advocates and TURN to specific projects, rather than discussing in detail each objection, argument, and proposal raised concerning each project, we find it more reasonable in this instance to consider as a whole the agreement reached by the settling parties, which include both Cal Advocates and TURN.

Most of the projects provide benefits with respect to upgrading and modernizing PG&E's IGP and Grid Modernization Plan. Many projects improve reliability, safety, and security. However, almost all projects support Distributed Energy Resources (DER) integration and connectivity to PG&E's system and at times, improving DER connectivity is forward-looking and does not provide immediate benefits. As discussed above, capital projects such as the ADMS Project, Distribution RT SCADA Replacement, Asset Data Enhancement, Wildfire Reclosing Operational Program, DCC Application Upgrades, Legacy SCADA Upgrade, Contract Support and FLISR System Maintenance upgrade and modernize PG&E's IGP and electric grid and improves DER connectivity.

Many of the concerns relate to the proper scale of the project, whether the project provides sufficient benefits, and whether costs are justified. All the above arguments relate to timing for when a project should be undertaken. As stated above, many DER projects are forward-looking and do not provide immediate benefits. This also affects the scale of the project as some portions of a project may be better off being undertaken at a later time. This also impacts costs in this GRC if some projects should be pushed back. In this case however, we find it more prudent not to reject the settlement based solely on timing considerations. While it is possible that some projects or phases of a project are better off being postponed for a later time, we find it more reasonable to give due regard to the agreement reached by the settling parties in arriving at an agreement to adopt these projects despite initial concerns raised by several of the settling parties. We understand that a settlement involves agreements and concessions from all parties. Thus, for IGP and Grid Modernization projects, we find it more reasonable to consider the agreement reached by settling parties that may have had initial differences and different recommendations considering the forward-looking nature of such projects. Based on the above, we find it reasonable to adopt the settlement amounts for IGP and Grid Modernization Plan capital for 2019 and 2020.

7.3.16. Capital Summary

Based on the above discussions, we find it reasonable to adopt PG&E's Electric Distribution capital forecasts for 2018, 2019, and 2020 of $1.731 billion, $1.958 billion, and $2.233 billion, respectively, with the understanding that the forecast amount for 2018 will be adjusted pursuant to Article 3.2 of the Settlement Agreement. We also find it reasonable to continue the one-way Rule 20A balancing account.

7.4. WMBA

As stated earlier in this chapter, the Settlement Agreement includes authority to establish a two-way WMBA, which will record CWSP-related expenses beginning in 2020. CWSP expenses include both O&M and capital costs that are included as part of the forecasts for the various organizations under Electric Distribution, which have been discussed in the O&M and capital sections of this chapter. Other CWSP expenses include O&M and capital costs for activities discussed within the Shared Services section (Chapter 10) and Human Resources section (Chapter 11) of this decision.

Under the Settlement Agreement, the authorized CWSP amounts are as follows:

CWSP Amounts	2020	2021	2022
Expense	$53,371,000	$55,292,000	$57,448,000
Capital	$603,341,000	$930,859,000	$1,151,108,000

Parties also agree to the following per mile costs for system hardening:

Year	Overhead per Mile Cost	Underground per Mile Cost
2020	$1.2 million	$4.4 million
2021	$1.3 million	$4.6 million
2022	$1.4 million	$4.8 million

Under Section 2.3.2.2 of the Settlement Agreement, the settling parties agree that a Tier 3 Advice Letter shall be filed if total spending is above 115 percent of the CWSP amounts specified above or if recorded average per mile unit costs for system hardening exceed 115 percent of the unit costs in the above table.

As explained in the beginning of this chapter, CWSP-related requests are dispersed in various PG&E organizations and appear in various sections of the decision. Most fall under and can be found in the Electric Distribution chapter. We reviewed these CWSP-related requests as part of our review of the different sections of the settlement.

Based on our review of the record of this proceeding, we agree with the settling parties on the need to establish the two-way WMBA to record both O&M and capital expenditures from PG&E's CWSP. The CWSP programs aggressively seek to mitigate wildfire risk by incorporating a risk-based approach to identify and address PG&E's assets that are most at risk from the threat of a wildfire and its associated events. We generally find the five main programs under CWSP as well as specific programs and projects proposed under the five main programs reasonable and necessary. As described earlier in this chapter, the five main programs are EVM, Wildfire System Hardening, Enhanced Operational Practices, Enhanced Situational Awareness, and Other Support Programs.

However, we agree with PG&E and the settling parties that the expanded mitigation activities and capital projects under CWSP are new and costs are difficult to predict. Even PG&E admits that the scope and specifics for some programs and projects are a still uncertain, especially those relating to system hardening. We thus find that a two-way balancing account addresses both under and over-spending that has a high likelihood of occurring. A two-way balancing account allows PG&E to spend more than the authorized amount in cases where the authorized forecast is below what is necessary to conduct necessary and important safety-related mitigations against wildfire risks. At the same time, the mechanism adopted in the Settlement affords the Commission some degree of reasonableness review if expenditures exceed a certain level above the authorized forecast. At the same time, if planned projects are not able to be completed or if actual expenditures end up lower than forecast, a two-way WMBA also allows PG&E to return unused amounts to ratepayers.

PG&E provides project summaries with costs for its CWSP projects in its workpapers. However, while we find that the 2020 forecasts are adequately supported by the record in the proceeding, considering the current progress of PG&E's wildfire mitigation activities, particularly those related to overhead and underground system hardening, the increased scope of work planned for 2021 and 2022 may not be feasibly undertaken or completed as scheduled given the constraints that PG&E and other parties state in their testimony.

Despite such uncertainty, PG&E's capital budget for CWSP projects in 2021 is over $300 million, more than 50 percent higher than its 2020 forecast. For 2022, the forecast is approximately $550 million higher or almost double the costs forecast for 2020. In addition, we find that there is insufficient support for the unit cost forecasts for 2021 and 2022 for PG&E's revised system hardening. PG&E uses a sample of recently completed projects to base its overhead unit cost forecast.

Instead, we find that using the 2020 capital forecast as a basis for 2021 and 2022 provides a more accurate forecast going forward. We find the O&M amounts reasonable as the 2021 and 2022 amounts authorized in the Settlement Agreement are only slightly higher (*i.e.,* approximately $2 and $4 million higher) than the TY amount and a portion of such increases can be attributed to escalation. For the capital amounts, we find it reasonable to modify the Settlement Agreement as follows:

a. The authorized capital amounts for 2021, and 2022 should be modified to $603.341 million, which is the agreed-upon capital funding for 2020 adopted by the Settlement Agreement;[83]
b. The authorized annual unit costs for system Hardening in 2021 and 2022 should be set at the 2020 level which is $1.2 million per overhead circuit mile and $4.4 million per underground circuit mile; and
c. The reasonable review threshold specified in Article 2.3.2.2 of the Settlement Agreement should be modified such that PG&E shall be required to file an application if CWSP expenditures are in excess of 130 percent of the authorized amount or if recorded per mile unit costs are in excess of 130 percent of the authorized unit costs specified above.

The settlement does not specify but we find that any overcollection as well as any undercollection that is less than 115 percent of the authorized amounts should be addressed via a Tier 2 advice letter.

We find that the above modifications provide a more realistic forecast but at the same time, the WMBA allows PG&E to spend what it necessary for additional wildfire mitigation subject to a reasonableness review by the Commission. For large undercollections, we find it reasonable for the review to be conducted via an application as opposed to a Tier 3 advice letter as provided by the Settlement Agreement. An application allows the Commission to conduct a more thorough review of large variances between forecast and recorded costs.

7.5. AB 1054 Compliance

Assembly Bill 1054 (Stats. 2019, ch. 79) (AB 1054) was signed into law by the Governor on July 12, 2019. Among other things, AB 1054 prohibits California's large electrical corporations from earning an equity return on their share of the first five billion dollars of capital expenditures that the state's electrical corporations aggregately spend on fire risk mitigation measures

[83] Settlement Agreement Section 2.3.2.1 Table 1.

approved in their wildfire mitigation plans. Each utility's share is determined by the Wildfire Fund allocation metric.

Specifically, among other things, AB 1054 enacted Pub. Util. Code Section 8386.3(e). This section states:

> "The commission shall not allow a large electrical corporation to include in its equity rate base its share, as determined pursuant to the Wildfire Fund allocation metric specified in Section 3280, of the first five billion dollars ($5,000,000,000) expended in aggregate by large electrical corporations on fire risk mitigation capital expenditures included in the electrical corporations' approved wildfire mitigation plans. An electrical corporation's share of the fire risk mitigation capital expenditures and the debt financing costs of these fire risk mitigation capital expenditures may be financed through a financing order pursuant to Section 850.1 subject to the requirements of that financing order."

AB 1054 also enacted Section 3280(n)(2), which states in relevant part:

> "…It is the expectation of the Legislature that the Wildfire Fund allocation metric is 64.2 percent for Pacific Gas and Electric Company, 31.5 percent for Southern California Edison Company, and 4.3 percent for San Diego Gas and Electric Company…"

The financing issues presented by AB 1054 in this GRC are 1) whether any of the capital expenditures forecasted in this GRC are prohibited from earning an equity return, and if so, which affected capital expenditures are covered by the prohibition, and 2) whether any affected capital expenditures can earn a debt return, and if so, at what level. This GRC also addresses the reasonableness of PG&E's CWSP capital expenditures in the capital section of this chapter and in the discussion concerning the WMBA.

7.5.1. PG&E's Position

PG&E interprets Section 8386.3(e) to mean that PG&E cannot earn an equity rate of return on its share of the first five billion dollars of capital expenditures that the state's large electrical corporations aggregately spend on wildfire risk mitigation measures. PG&E states that its share, according to Section 3280(n)(2), is 64.2 percent, or $3.21 billion, as determined according to the Wildfire Fund allocation metric.

PG&E expects to reach the $3.21 billion in wildfire mitigation capital expenditures through a combination of costs recorded in its Wildfire Mitigation Plan Memorandum Account (WMPMA) and costs that are forecasted in this GRC for the CWSP. If the Commission approves PG&E's forecast of $2.835 billion of CWSP capital expenditures in this GRC (comprised of $2.805 billion in electric distribution and $0.031 billion in common utility costs), then these CWSP capital expenditures will be included in the $3.21 billion of capital expenditures prohibited from receiving an equity return.

PG&E asserts that, based on its interpretation of Section 8386.3(e), it can finance these excluded CWSP capital expenditures with securitized debt, subject to the financing requirements specified in Section 850.1. PG&E plans to seek authority to securitize these CWSP capital expenditures in a separate application. During this period, PG&E is requesting in this GRC to earn a debt return for the $2.835 billion of CWSP capital expenditures that are excluded from earning an equity return. After applying the appropriate tax adjustments for the equity exclusion and debt treatment, PG&E states that its proposed adjustments will lower the GRC revenue requirement by $22 million in 2020, $57 million in 2021, and $105 million in 2022.

According to PG&E, pursuant to Section 850(a)(2), the Commission must first determine that the capital expenditures are "just and reasonable" before PG&E can file an application to securitize the CWSP costs with debt. As such, PG&E is also requesting that this decision determine that its forecasted $2.835

billion of CWSP capital expenditures for 2019 through 2022 are just and reasonable.

No parties oppose PG&E's interpretation and application of AB 1054's financing provisions on its GRC forecast.

7.5.2. Settlement Provision

Article 2.3.2.4 of the Settlement Agreement states:

> "The revenue requirement in this Agreement includes reductions for AB 1054 return on equity (Pub. Util. Code Section 8386.3) in the following amounts: $22 million in 2020, $57 million in 2021, and $105 million in 2022. The Settling Parties agree that PG&E may seek to revise the forecast adopted in this Agreement for CWSP capital consistent with AB 1054 in an application to securitize the CWSP capital adopted in this GRC."

7.5.3. Discussion

According to Section 8386.3(e), PG&E cannot earn an equity rate of return on its share of the first five billion dollars of capital expenditures that the state's large electrical corporations aggregately spend on wildfire risk mitigation measures approved in their wildfire mitigation plans. PG&E's share, as determined by the Wildfire Fund allocation metric specified in Section 3280(n)(2), is 64.2 percent, or $3.21 billion. Therefore, PG&E cannot earn an equity return on the first $3.21 billion of capital expenditures it spends on wildfire mitigation measures included in its approved wildfire mitigation plan.

In this GRC, PG&E forecasts that it will spend $2.835 billion in CWSP capital expenditures from 2020 through 2022. Accordingly, PG&E is not seeking an equity return for this $2.835 billion in GRC CWSP capital expenditures.

However, as discussed in the WMBA section, the decision modifies the Settlement Agreement with respect to CWSP capital forecasts for 2021 and 2022 resulting in an authorized amount of $1.952 billion in CWSP capital expenditures. This amount is less than the $3.21 billion of wildfire capital expenditures that are subject to the equity rate base exclusion.

In lieu of an equity return, PG&E is requesting in this GRC to earn a debt return on CWSP capital expenditures for this GRC period, with the return set to its currently authorized cost of debt. The settling parties agree to the revenue requirement reductions PG&E proposed. Effectively, the settling parties are agreeing to PG&E's application of AB 1054 in calculating the annual revenue requirement reductions, which removes an equity return and the related taxes on the CWSP capital expenditures in this GRC period and applies a debt return on the CWSP costs based on PG&E's cost of debt at the time PG&E filed its briefs.

Section 8386.3(e) allows PG&E to finance the GRC CWSP capital expenditures with a financing order pursuant to Section 850.1. Since Section 8386.3(e) allows debt financing for these wildfire mitigation capital expenditures, it is reasonable to allow PG&E to earn a debt return, based on its currently authorized cost of debt, on the GRC CWSP capital expenditures until the Commission can decide PG&E's future Section 850.1 application. PG&E's authorized cost of debt is an appropriate forecast of the financing costs for the GRC CWSP capital expenditures.

Thus, we adopt the settling parties' proposed methodology of applying AB 1054 in calculating the annual revenue requirement reductions, which removes an equity return and the related taxes on the authorized amount of CWSP capital expenditures in this GRC period. We also adopt the settling parties' proposed revenue requirement reductions of $22 million in 2020, $57 million in 2021, and $105 million in 2022, resulting from the debt treatment of the GRC CWSP capital expenditures subject to any resulting adjustment as a result of the modification to the CWSP capital being authorized from $2.835 billion to $1.952 billion.

The above methodology applies a debt return on the authorized CWSP capital amount based on PG&E's authorized cost of debt at the time PG&E filed its brief. However, we find that PG&E should update its revenue requirement to reflect the cost of debt that is authorized at the time this decision is approved in the advice letter implementing this decision.

The settling parties also agree that PG&E may revise its GRC forecasts in the application in which PG&E will seek to securitize the CWSP costs. Because financing pursuant to Section 850.1 requires the utility to recover the costs through a charge separate from the GRC revenues, our interpretation of this portion of the settlement is the settling parties agree that, if PG&E seeks Section 850.1 financing, PG&E should, in the application in which it seeks Section 850.1 financing, adjust its GRC revenue requirement by removing the debt return and other capital-related expenses from its GRC forecast. We agree with the settling parties' proposal, as we understand it, that PG&E should revise its GRC forecasts, should PG&E seek to finance the CWSP capital expenditures under Section 850.1 financing, because financing the CWSP capital expenditures under Section 850.1 is performed through a fixed recovery charge and is not recovered through the traditional GRC revenue requirement.

Additionally, PG&E requests that the Commission find the GRC CWSP capital expenditures to be just and reasonable. Based on PG&E's interpretation of Section 850.1, PG&E states that the Commission must find that its wildfire mitigation capital expenditures are just and reasonable before it can seek to finance these expenditures under Section 850.1. We discussed the reasonableness of CWSP capital expenditures in the capital section of this chapter and in the discussion concerning the WMBA.

For other capital expenditures subject to the Section 8386.3(e) equity return exclusion, the settling parties agree that PG&E may file a Tier 3 advice letter to seek a Commission finding that these capital expenditures are just and reasonable. We agree with the settling parties that PG&E should seek a reasonableness finding for other wildfire mitigation capital expenditures, but with one procedural clarification. According to PG&E, the other wildfire mitigation capital expenditures are costs it recorded in the WMPMA. Because these capital expenditures are recorded in the WMPMA, PG&E shall seek a reasonableness review of these costs through an application rather than an advice letter. Reasonableness review of costs recorded in the WMPMA will require a thorough Commission review, including the review of evidence that PG&E will need to provide for support, and is therefore more appropriately conducted through an application.

In addition, because the Commission believes transparency and accountability of PG&E's compliance with AB 1054 is warranted, we direct PG&E to make an explicit showing in its Annual Electric True-Up advice letter filings going-forward to report the total amount of PG&E's $3.21 billion wildfire mitigation capital that has been found just and reasonable and excluded from equity rate base, in which proceeding this finding has occurred, and the remaining amount and plan for the wildfire mitigation capital that has yet to be excluded from rate base.

8. Energy Supply

This section discusses PG&E's Energy Supply O&M and capital costs. Energy Supply costs are for work activities related to operating and maintaining PG&E's generation facilities and include PG&E's energy procurement administration costs, generation support costs, as well as costs for acquiring power to meet customer demands. Capital projects are for generation equipment, dams, and waterways, safety and regulatory projects, infrastructure, and other capital projects.[84]

As stated in Article 2.4 of the Settlement Agreement, the settling parties agree to a TY2020 forecast of $595.853 million forecast for Energy Supply O&M costs or $600.436 million without the labor escalation adjustment discussed in the Human Resources section. The above reduction represents a $4.000 million reduction to PG&E's proposed costs. All the reductions are from Energy Policy & Procurement costs and were made in the interest of customer affordability.[85]

The table below shows PG&E's O&M forecasts under Energy Supply and includes expenses for Hydro Operations, Natural Gas & Solar, Energy Procurement Administrative, Energy Supply Technology Programs, and Nuclear expenses, as well as the corresponding amounts agreed upon in the Settlement Agreement. The amounts do not reflect the labor escalation adjustments which are discussed in the Human Resources Section in chapter 11 of the decision.

Energy Supply O&M	PG&E Forecast	Settlement Reduction	Settlement Amount
Hydro Operations	$144,736,000	$0	$144,736,000
Natural Gas & Solar	$55,259,000	$0	$55,259,000
Energy Procurement Administration	$40,606,000	$4,000,000	$36,606,000
Technology Programs	$2,104,000	$0	$2,104,000
Nuclear Operations	$357,732,000	$0	$357,732,000
Total	**$600,436,000**	**$4,000,000**	**$596,436,000**

For capital projects, the Settlement Agreement adopts all of PG&E's proposed costs of $416.223 million for 2018, $372.518 million for 2019, and

84 Exhibit 188 at 1.

85 Settlement Agreement Article 2.4.

$285.754 million for 2020. Pursuant to Article 3.2, the amount for 2018 is subject to adjustment as discussed in section 15 of the decision. The 2018 forecast will be replaced with PG&E's recorded capital costs in 2018.

Energy Supply Capital PG&E Forecast and Settlement Amount	**2018**	**2019**	**2020**
Hydro Operations	$238,415,000	$230,666,000	$214,842,000
Natural Gas & Solar	$4,598,000	$6,946,000	$7,842,000
Energy Procurement Administration	$0	$0	$0
Technology Programs	$29,908,000	$23,651,000	$22,422,000
Nuclear Operations	$143,300,000	$111,255,000	$40,648,000
Total	**$416,223,000**[86]	**$372,518,000**	**$285,754,000**

8.1. Hydro Operations

Hydro Operations costs are expense forecasts necessary to operate and maintain PG&E's hydroelectric generation facilities. According to PG&E, its hydroelectric system is one of the largest investor-owned hydroelectric systems in the country.[87] PG&E's hydro system stretches for nearly 500 miles and its portfolio includes 66 powerhouses of varying sizes with 106 generating units.[88] The powerhouses are organized into five operating areas and operated under 25 Federal Energy Regulation Commission (FERC) licenses. The five operating areas are: Shasta; DeSabla; Central; King's Crane Valley; and Helms.

8.1.1. O&M

PG&E manages its hydro generation assets through a centralized program management process and costs are standardized under defined work groupings called MWC. The MWCs are grouped under various functions such as

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86 The sum of the individual totals is $416.221 million with the difference due to rounding.

87 Exhibit 146 at 4-1.

88 *Id* at 4-7.

operations, maintenance, environmental, and capital projects. The hydro organization uses 13 MWCs for expense costs and these MWCs are described briefly below. Individual forecasts for each MWC are shown in page 5 of Appendix B to the Settlement Agreement.

MWC AB – Miscellaneous Expense: includes costs to support power generation contracts and land conservation commitments.

MWC AK – Manage Environmental Operations: are for labor costs to support environmental stewardship programs.

MWC AX – Maintain Reservoirs, Dams, Waterways: are for maintenance and costs for inspections and studies to meet best engineering practices.

MWC AY – Habitat and Species Protection: are costs to support habitat and species protection.

MWC EP – Manage Property and Buildings: includes costs to manage land rights required to operate hydro generating stations.

MWC ES – Implement Environmental Projects: includes costs to implement projects in support of environmental protection.

MWC IG – Manage Balancing Account Processes: are for costs to implement new license conditions for FERC licenses issued after 2017.

MWC KG – Operate Hydro Generation: are for costs associated with operation of hydro generating and associated facilities.

MWC KH – Maintain Hydro Generating Equipment: are costs for activities associated with maintenance of generating equipment or components to support hydro generation activities.

MWC KI – Maintain Hydro Buildings, Grounds, and Infrastructure: are for maintenance costs of buildings, grounds, and infrastructure associated with hydro generation activities.

MWC KJ – Regulatory Compliance: are for costs for managing license compliance and required surveys and studies to maintain compliance.

MWC OM – Operational Management: are for costs to provide supervision and management support.

MWC OS – Operational Support: includes labor costs to provide non-supervisory services and support.

8.1.2. Capital

There are nine MWCs for capital projects which are briefly described below. Individual costs for each project are shown in the table below.[89]

Hydro Capital PG&E Forecast and Settlement Amount	2018	2019	2020
Office Furniture and Equipment	$15,000	$16,000	$16,000
Tools and Equipment	$1,024,000	$685,000	$702,000
Relicensing Hydro Generation	$1,273,000	$888,000	$427,000
Implement Environmental Projects	$488,000	$533,000	$507,000
Install/Replace Hydro Safety and Regulatory	$23,560,000	$23,266,000	$24,429,000
Install/Replace Hydro Generation Equipment	$91,913,000	$117,867,000	$109,235,000
Install/Replace Reservoirs, Dams and Waterways	$52,714,000	$39,571,000	$54,711,000
Install/Replace Hydro Infrastructure	$37,495,000	$14,837,000	$5,345,000
Relicensing and New License Implementation	$29,933,000	$33,003,000	$19,470,000
Total	**$238,415,000**	**$230,666,000**	**$214,842,000**

MWC 03 – Office Furniture and Equipment: includes costs to install or replace office furniture or other accessory equipment to support hydro generation operations.

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89 Amounts are shown in Appendix B of the Settlement Agreement at 9 to 13.

MWC 05 – Tools and Equipment: are for capital tools and equipment to support hydro generation operations.

MWC 11 – Relicensing Hydro Generation: are for costs to obtain new licenses as existing ones expire and costs associated with capital projects to comply with license requirements.

MWC 12 – Implement Environmental Projects: are for needed environmental projects such as oil spill prevention systems and equipment.

MWC 2L – Install /Replace Hydro Safety and Regulatory: are for costs to install/replace safety or regulatory required equipment, or other related accessory equipment needed to support hydro generation operations.

MWC 2M – Install/Replace Hydro Generating Equipment: are for capital costs to install or replace hydro generating equipment.

MWC 2N – Install/Replace Reservoirs, Dams and Spillways: are for capital projects to install or replace hydro generating and other accessory structures and equipment needed to support hydro generation water conveyance.

MWC 2P – Install/Replace Hydro Infrastructure: are for capital projects to install or replace buildings, roads, and bridges needed to support hydro generation operations.

MWC 3H – Relicensing and New License Implementation: are for costs to renew and obtain new hydro operating licenses as well as the installation of new equipment and other capital projects required to obtain or renew the licenses.

8.1.3. Positions of the Parties

The Settlement Agreement adopts all of PG&E's proposed O&M and capital costs under Hydro Operations.

Cal Advocates originally proposed a reduction of $11.775 million to PG&E's O&M unadjusted forecast.[90] Cal Advocates proposed reductions for MWC Miscellaneous Expense, MWC Manage Various Balancing Accounts Process, MWC Regulatory Compliance, and MWC Operational Support. Cal Advocates also proposed using 2018 recorded costs totaling $212.263 million for capital projects which is $26.152 million less than PG&E's forecast of $238.415 million.

TURN originally recommended reducing the forecast for FERC fees by $0.802 million. These amounts are included in MWC KJ - Regulatory Compliance Hydro Generation.

8.1.4. Discussion

We reviewed the proposed settlement amounts for Hydro Operations as well as the testimony presented by parties and any comments from non-settling parties and find the proposed O&M and capital costs to be reasonable and supported by the record of the proceeding.

The settlement adopts PG&E's adjusted O&M forecast of $144.617 million which is approximately $3.994 million or 2.8 percent higher than base year recorded 2017 expenses of $140.623 million. PG&E's forecasts were developed using different approaches to estimate costs. Costs for routine operations, maintenance, and compliance are primarily based on labor and other recurring costs which are typically consistent year over year.[91] Thus, we find that the forecast is generally reflective of historical costs.

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[90] PGE Exhibit 32, Joint Comparison Exhibit, 2-240—2-256.

[91] Exhibit 188 at 4 to 5.

Regarding Cal Advocates' original objections to the four MWCs mentioned in the above section, Cal Advocates' recommendations are based on applying historical costs to determine the TY2020 forecasts. However, as argued by PG&E in its rebuttal testimony, PG&E based its forecasts for the above MWCs on 2017 costs and Cal Advocates' recommendations do not apply any sort of escalation to the 2017 recorded costs.[92] In addition, Cal Advocates' recommendations did not consider non-base cost drivers or changes in actual work to be performed that were described in PG&E's testimony.[93] Regarding TURN's recommendation, PG&E calculated the projected FERC fees based on average annual generation which we find reasonable. Based on the above, we find the settlement amount of $144.617 million for O&M costs reasonable and should be adopted.

Regarding capital costs, we reviewed the proposed capital projects and find the projects and settlement amounts for 2018, 2019, and 2020 reasonable. The proposed amount for 2018 capital costs is subject to the adjustment described in Article 3.2 of the settlement wherein PG&E's 2018 forecast will be replaced with PG&E's recorded capital costs in 2018. The proposed projects are for maintenance buildings, dams, roads, and other infrastructure necessary to operate PG&E's hydro generation system. Other projects are to replace, maintain, or install equipment and infrastructure in support of or necessary to operate or obtain licenses to operate the hydro systems. Cal Advocates originally proposed using recorded costs of $212.263 for 2018 but this is addressed by the adjustment to 2018 costs described in Article 3.2 of the settlement. We find no issue in adopting the proposed capital amounts. Therefore, the settlement

[92] Exhibit 71 at 4-6 to 4-7.

[93] Exhibit 71 at 4-8 to 4-17.

amounts of $238.415 million for 2018, $230.666 million for 2019, and $214.842 million for 2020 for hydro operations capital projects should be adopted coupled with the adjustment to 2018 costs described in Article 3.2. Article 3.2 is discussed with greater detail in chapter 15 of the decision.

We also have no issues and support the agreement concerning the safety management system framework for hydroelectric facilities as described in Article 2.4.4 of the Settlement Agreement.

8.1.5. Hydro Licensing Balancing Account (HLBA)

PG&E is requesting continuance of the HLBA which is a two-way balancing account that records O&M and capital costs of FERC Hydro licensing and license implementation costs. The Settlement Agreement continues the HLBA but modifies it to include regulatory fees, costs associated with implementation of the Crane Valley Recreation Settlement Agreement[94], and costs associated with work required due to the 2017 Oroville spillway incident.[95]

We agree that two-way balancing treatment of costs tracked in the HLBA should continue because of the difficulty in accurately forecasting the timing for issuance of FERC licenses associated with hydro generation. The regulatory process can be complex and includes separate state and federal reviews that run parallel to the FERC process. In addition, the measures required and conditions imposed for obtaining licenses vary, often requiring studies that need to be

[94] The Crane Valley Recreation Settlement Agreement is a yet-to-be implemented condition of the Crane Valley license issued in 2003. The Settlement Agreement between PG&E and the U.S. Forest Service (USFS) became a requirement of the FERC license for the Crane Valley Project (FERC No. 1354) when the license was issued September 16, 2003. The Settlement Agreement states that if the USFS cannot provide funding, PG&E is required to fund the full cost of rehabilitating the facilities but on a delayed implementation schedule. Due to various factors, largely outside of PG&E's control, the implementation has been delayed. (PG&E Testimony, Chapter 8, p. 8-8)

[95] Settlement Agreement Article 4.1.1.3.

completed beforehand. We also do not object to the inclusion of the costs mentioned above, because regulatory fees and work as a result of the Oroville spillway incident are necessary costs that will be incurred by PG&E.

With respect to the inclusion of costs associated with the Crane Valley Recreation Settlement Agreement, the HLBA only allows recovery of costs for licenses issued on or after January 1, 2012. However, rehabilitation and repair of various facilities required by FERC for the Crane Valley Project have been delayed due to factors outside of PG&E's control.[96] Thus, these costs are only being incurred now even though the license for the Crane Valley Project was issued prior to 2012. Inclusion of costs relating to the Crane Valley Settlement Agreement should be treated as an exception to the requirement that only licenses issued on or after January 1, 2012 should be included for recovery in the HLBA.

Based on the above, we find that modification of the HLBA as described in Article 4.1.1.3 of the Settlement Agreement is reasonable and should be adopted.

8.1.6. Non-Bypassable Charge for Hydro Facilities

PG&E originally proposed recovering costs to support the protection and enhancement of beneficial public values on PG&E's watershed lands through a non-bypassable charge. This proposal was objected to by Cal Advocates, JCCA, Vote Solar, and SEIA, and TURN proposed modifications to PG&E's request.

Because the Settlement Agreement removes PG&E's request regarding the non-bypassable charge,[97] it is unnecessary to review this issue.

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[96] Exhibit 71 at 8-12 to 8-13.

[97] Settlement Agreement Article 2.4.3.1.

8.1.7. Accounting Change for Hydroelectric Licensing Costs

Article 2.4.3.2 of the Settlement Agreements sets forth several conditions for when relicensing capital projects shall be operative. The conditions involve filing of a relicense application and issuance or cancellation of the applicable FERC license. We find no issue with the conditions set forth and note that the conditions involve licensing matters under the purview of FERC.

8.2. Natural Gas & Solar Generation Operations

This section addresses the O&M and capital costs to operate PG&E's natural gas and photovoltaic (PV) solar generation facilities. PG&E's natural gas generation fleet consists of the Gateway Generating Station (Gateway), the Colusa Generating Station (Colusa), and the Humboldt Bay Generating Station (Humboldt). Gateway and Colusa are combined cycle plants[98] while Humboldt uses reciprocating engine technology and fuel cell facilities.[99] PG&E also has 10 ground-mounted PV solar generating stations which were approved in D.10-04-052.[100] In addition, PG&E has three small PV solar generation facilities located in San Francisco.

8.2.1. O&M

PG&E also manages its natural gas and solar generation facilities through a centralized management process and costs are standardized under defined MWCs. The MWCs for O&M costs are grouped into four categories: operations, maintenance, environmental, and management and support.

Operations

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[98] A combined cycle plant uses both a gas turbine and a steam turbine to produce up to 50 percent more electricity from the same fuel as compared to a traditional cycle plant.

[99] Exhibit 146 at 5-1.

[100] D.10-04-052 OP 7.

Operations include costs for activities such as labor to operate natural gas, PV solar, and fuel cell facilities as well as associated engineering and clerical support personnel. Other costs relate to site management, support services, materials, and contracts for operating the plants. MWCs included under Operations are MWC KK – Operate Fossil Generation and MWC KQ – Operate Alternative Generation.

Maintenance

Maintenance is used to address labor to maintain the natural gas, PV solar, and fuel cell facilities but also includes costs for materials and required contracts such as maintenance and engineering services. MWCs under Maintenance are MWC KL – Maintain Fossil Generating Equipment, MWC KM – Maintain Fossil Buildings, Grounds, and Infrastructure, MWC KR – Maintain Alternative Generation Generating Equipment, and MWC KS – Maintain Alternative Generation Buildings.

Environmental Support

This function is for addressing waste management and required environmental permits as well as support services, materials, and contracts for disposal of waste materials. MWC AK – Manage Environmental Operations is under this function.

Operations Management and Operations Support

This includes costs for internal management and support labor for operations. MWCs under this function are MWC OM – Operational Management and MWC OS – Operational Support.

8.2.2. Capital

There are seven MWCs for capital projects which are briefly described below. Individual costs for each project are shown in the table below.[101]

Natural Gas & Solar Capital PG&E Forecast and Settlement Amount	2018	2019	2020
Office Furniture and Equipment	$193,000	$0	$0
Tools and Equipment	$357,000	$366,000	$375,000
Install/Replace for Fossil Safety and Regulatory	$101,000	$0	$0
Install/Replace Fossil Generating Equipment	$3,081,000	$4,782,000	$6,465,000
Install/Replace Fossil Buildings, Grounds, and Infrastructure	$355,000	$1,014,000	$203,000
Install/Replace for Alternative Safety and Regulatory	$23,000	$24,000	$24,000
Install/Replace Alternative Generation Equipment	$488,000	$760,000	$775,000
Total	**$4,598,000**	**$6,946,000**	**$7,842,000**

MWC 03 – Office Furniture and Equipment: includes costs to install or replace office furniture or other accessory equipment to support natural gas and PV solar generation operations.

MWC 05 – Tools and Equipment: are to replace tools and equipment that have reached the end of their useful lives and for tools and equipment needed to increase efficiency and productivity.

MWC 2R – Install/Replace for Fossil Safety and Regulatory: are for fossil projects necessary to address specific safety and environmental risks identified by O&M staff.

[101] Amounts are shown in Appendix B of the Settlement Agreement at 9 to 13.

MWC 2S – Install/Replace Fossil Generating Equipment: include capital projects necessary for reliability of PG&E's fossil generating equipment.

MWC 2T – Install/Replace Fossil Buildings and Grounds and Infrastructure: these are for infrastructure related capital projects for natural gas facilities.

MWC 3A – Install/Replace for Alternative Generation Safety and Regulatory: these are for capital projects associated with alternative generation equipment that are necessary to address specific safety and environmental risks identified by O&M staff.

MWC 3B – Install/Replace Alternative Generation Equipment: include capital projects necessary for reliability of PG&E's alternative generation equipment.

8.2.3. Positions of the Parties

The Settlement Agreement adopts all of PG&E's proposed O&M and capital costs under Natural Gas and Solar Generation Operations.

Cal Advocates originally recommended a TY2020 forecast of $52.178 million for O&M costs which is $3.081 million less than PG&E's unadjusted forecast. Cal Advocates recommended using 2017 recorded costs for MWC KK – Operate Fossil Generation, MWC KR – Maintain Alternative Generation Generating Equipment, MWC KM – Maintain Fossil Buildings, Grounds, and Infrastructure, and MWC OS – Operational Support. For capital requests, Cal Advocates originally recommended using 2018 recorded costs.

TURN originally agreed with Cal Advocates' reductions for MWC KK – Operate Fossil Generation and MWC KM – Maintain Fossil Buildings, Grounds, and Infrastructure. For MWC – KR Maintain Alternative Generation Generating Equipment, TURN recommended using an average of 2017 and 2018 recorded costs, plus 5 percent for escalation, which results in an additional reduction of $0.356 million. TURN also recommended a reduction of $1.600 million for MWC KL – Maintain Fossil Generating Equipment. TURN recommended a total reduction of $4.642 million for O&M costs.

8.2.4. Discussion

The settlement adopts PG&E's O&M forecast of $55.219 million which is approximately $3.890 million higher than base year 2017 expenses of $51.401 million. PG&E developed its forecasts using base year costs for operating and maintaining its natural gas, PV solar, and fuel cell facilities as a basis. Costs have been typically consistent from year to year.[102] The forecast then applies adjustments such as escalation and other cost drivers in order to arrive at the TY2020 forecast. For natural gas and solar, additional costs for increased engine maintenance for Humboldt, solar warranty expirations in 2017, increase in permit fees, and cost model changes were taken into account by the forecast. These were slightly offset by a reduction of approximately $1.1 million due to staffing optimization and reduction. Based on the above, we find the TY2020 forecast and settlement amount of $55.219 million reasonable and fairly reflects projected costs.

Regarding Cal Advocates' original objections to the four MWCs mentioned in the preceding section, as was the case in the discussion of Hydro Operations O&M costs, Cal Advocates' recommendations do not take into account cost escalation. We thus find PG&E's method, which is to use base year costs as a basis that is then adjusted or reduced by escalation and other specific cost drivers, to be a more reasonable method.

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[102] Exhibit 188 at 18.

With regards to TURN's objection regarding the forecast for MWC KL - Maintain Fossil Generation Equipment, TURN's recommendation was based on normalizing engine overhauls for Humboldt and basing long-term service agreement (LTSA) costs for Gateway and Colusa. However, as stated in PG&E's rebuttal testimony, the 10 reciprocating engines at Humboldt are not operated for an equal number of hours and so engine overhauls are based on run-hours and start-stops. Thus, we find it reasonable for engine overhauls at Humboldt to be on a staggered schedule based on hours of operation instead of average hours of operation for all engines. With respect to LTSA costs, PG&E explains that costs in 2018 were unusually low and we find that applying average LTSA costs is reasonable.

TURN also objects to the forecast in MWC KR – Maintain Alternative Generation Generating Equipment. PG&E's expenses on PV maintenance was due to the solar plants coming off warranty, however, the recorded amounts in 2018 did not justify the amounts requested by PG&E. PG&E's rebuttal testimony clarified that the maintenance costs were low because PG&E enforced a $0.255 million performance penalty against PG&E's contract service provider and the fourth quarter 2018 payment was paid in 2019rather in 2018 so there were only three quarterly payments made in 2018. Thus, PG&E's 2020 forecast for MWC KR is reasonable and we adopt it.

With respect to capital costs, parties do not object to the necessity of the proposed projects which we find reasonable and necessary to operate and maintain PG&E's natural gas, PV solar, and fuel cell facilities. For 2018 costs, Article 3.2 of the Settlement Agreement will adjust PG&E's 2018 forecast with recorded expenditures for 2018 which addresses Cal Advocates' concern and which we find reasonable. We also find the proposed amounts for 2019 and 2020 to be reasonable and which are not opposed by any party. Therefore, the settlement amounts of $4.598 million for 2018, $6.946 million for 2019, and $7.842 million for 2020 for natural gas and solar generation operations capital projects should be adopted subject to the adjustment for 2018 costs described in Article 3.2 of the settlement.

8.2.5. LTSA costs

The Settlement Agreement provides in Article 2.4.5 that costs associated with major LTSA outages at Gateway and Colusa be levelized. We reviewed the proposal and find it consistent with D.17-05-013[103] to spread out periodic LTSA costs. The variable LTSA payments which are due quarterly will be assumed consistent with the average recorded costs from 2015 to 2017.

8.3. Energy Procurement Administration

PG&E supplies electricity to its bundled customers through utility-owned generation assets and procurement from third-party generators. Natural gas is supplied to core customers through procurement contracts with producers and marketers.[104] The Energy Policy and Procurement (EPP) organization is responsible for front-office and back-office functions associated with energy procurement. Front-office functions include planning, procuring, scheduling, and dispatching electricity and natural gas for customers while back-office functions include administering procurement agreements and ensuring timely payments to suppliers.

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[103] Decision in PG&E's TY2017 GRC application.

[104] Exhibit 146 at 6-1.

8.3.1. O&M

The Settlement Agreement applies a $4.000 million reduction to PG&E's adjusted TY2020 forecast for EPP costs of $40.584 million. EPP includes four MWCs which are briefly described below.

MWC AB – Administration: represents overall administration costs.

MWC CT – Acquire and Manage Electric Supply: includes costs to acquire and manage electric supply which represents the majority of costs under EPP.

MWC CV – Acquire and Manage Gas Supply: includes costs to acquire and manage PG&E's natural gas supply.

MWC CY – Manage Electric Grid Ops: includes costs associated with grid integration and innovation.

8.3.2. Discussion

Parties did not oppose PG&E's TY2020 unadjusted forecast of $40.606 million. However, the settlement applies a $4.000 million reduction to the adjusted forecast of $40.584 million in the interest of customer affordability. The Settlement Motion adds that the $4.000 million reduction for Energy Supply (in particular EPP O&M costs) is part of a reasonable compromise of the positions taken by parties. We find the adjustment fair and reasonable and agree with the Settlement Motion that it forms part of reasonable compromises made by parties to reach an agreement. In addition, we find no indication that the reduction of $4.000 million will impair the EPP organization's ability to perform its functions. In addition, the settlement only includes a reduction in costs and not a reduction in the functions that are performed by the EPP organization. PG&E had also forecast a primarily flat headcount for TY2020[105] and projected decreases in non-labor costs.[106] Therefore, we find the settlement amount of $36.584 million for EPP costs reasonable.

8.4. Technology Programs

Technology Programs under Energy Supply support the operational processes critical to PG&E's generation of electric supply and procurement of electric and gas supply, and cover the technology needs and initiatives for nuclear generation, non-nuclear generation, and EPP. Technology Programs only has one MWC for O&M costs and a single capital project and so these will be discussed together.

The settlement adopts PG&E's O&M forecast of $2.103 million for MWC JV – Maintain IT Apps & Infrastructure and capital forecast of $29.908 million for 2018, $23.651 million for 2019 and $22.422 million for 2020 for MWC 2F – Build IT Apps & Infrastructure. Once again, the 2018 capital amount is subject to the adjustment described in Article 3.2 of the settlement. The Build IT Apps & Infrastructure capital costs are for upgrades to IT systems and software applications that are at risk of becoming unstable due to age and other technical factors.

8.4.1. Discussion

We reviewed the proposed amounts in the Settlement Agreement as well as the relevant testimony regarding this area and find the proposed amounts for both O&M and capital costs reasonable and necessary to upgrade and maintain the IT systems and technology associated with electric generation and electric and gas procurement. Parties do not oppose PG&E's forecasts except for Cal

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[105] Exhibit 146 at 6-4 to 6-5.

[106] *Id* at 6-23.

Advocates' original recommendation to apply 2018 recorded costs of $25.829 million instead of PG&E's 2018 forecast which is addressed by the adjustment described in Article 3.2 of the Settlement Agreement. As was the case regarding discussion of this issue in prior topics under Energy Supply, we find no issue with adopting the 2018 adjustment described in Article 3.2 and likewise have no issue with the proposed amounts for 2019 and 2020.

8.5. Nuclear Operations

Nuclear Operations costs are the O&M and capital costs associated with operating and maintaining the Diablo Canyon Power Plant (DCPP). The DCPP is a two-unit, Westinghouse Pressurized Water Reactor nuclear station located in San Luis Obispo, California. Pursuant to D.18-01-022, Unit 1 of the DCPP is scheduled to be retired upon the expiration of its Nuclear Regulatory Commission (NRC) operating license in November 2024 while Unit 2 is scheduled to be retired in August 2025.[107] In the ALJ ruling dated September 6, 2019, it was clarified that issues relating to the shutdown or closure date of DCPP are better raised in a Petition for Modification of D.18-01-022 and shall not be addressed here.[108] A4NR filed a Petition for Modification of D.18-01-022 on October 1, 2019, requesting that any party may propose modifications to the Settlement Agreement regarding DCPP costs in light of potential changes to the timing of the DCPP retirement.[109] WEM proposed that relevant changes from the petition to modify D.18-01-022 be incorporated and that the decision in this proceeding be modified to incorporate these changes.

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107 D.18-01-022 OP 1 at 59.

108 ALJ Ruling dated September 6, 2019 at 2.

109 Settlement Agreement Article 2.4.2.1 at 13 to 14.

The petition was subsequently denied.[110] The decision shall therefore address the reasonableness of PG&E's proposed O&M and capital costs relating to DCPP as an operating unit for this GRC cycle. In any case, the Settlement Agreement already provides a mechanism to incorporate any relevant changes via a petition to modify this decision. As stated above, this decision continues to assume that the DCPP will be in operation for this GRC cycle.

8.5.1. O&M

The Settlement Agreement adopts all of PG&E's proposed O&M costs for TY2020 totaling $357.330 million. DCPP operations include 12 MWCs covering O&M costs which are described briefly below.

MWC AB – Miscellaneous Expense: includes labor, materials, contract, and other maintenance costs associated with the refueling outage scheduled for 2022.

MWC AK – Manage Environmental Order and **MWC EO – Provide Nuclear Support**: comprise the two MWCs for managing environmental protection programs mandated by federal, state, and local regulations. Costs also include various fees and permit costs.

MWC BP – Manage DCPP Business: includes non-labor fees, Diablo Canyon safety committee costs, and land management program and property leasing costs.

MWC BQ – DCPP Support Services: includes costs for loss prevention and for the DCPP security department as well as non-labor costs for weather forecasting, modeling, emergency plan public education, drill preparation, and other related costs.

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[110] D.20-03-006, March 12, 2020.

MWC BR – Operate DCPP Plant: covers costs for operation of the plant, radiation control, managing radioactive waste, plant chemistry control, radiological effluent monitoring, oversight for radioactive material, and work practices to minimize radiation dosage.

MWC BS – Maintain DCPP Plant Assets: includes maintenance costs and repair of DCPP plant assets.

MWC BT – Nuclear Generation Fees: mostly consists of contract costs and fees from the NRC.

MWC BV – Maintain DCPP Plant Configuration: mostly consists of costs for the engineering department which is responsible for maintaining the configuration of the plant.

MWC IG – Manage Various Balancing Account Processes: this MWC tracks two balancing accounts: the Nuclear Regulatory Commission Regulatory Balancing Account (NRCRBA) and the Diablo Canyon Seismic Study Balancing Account (DCSSBA). The activities tracked under the NRCRBA are driven by NRC mandates and includes projects such as cyber security and seismic studies, national fire protection standards, and emergency planning.[111]DCSSBA activities are driven by AB 1632 and include projects such as the Long Term Seismic Program.[112]

MWC OM – Operational Management: consists of labor costs for senior managers (vice-presidents and directors).

MWC OS – Operational Support: includes costs for numerous support organizations needed to operate and maintain the DCPP.

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[111] Exhibit 190 at 9.

[112] *Ibid*.

8.5.2. Capital

There are four MWCs for capital projects which are briefly described below. Individual costs for each project are shown in the table below.[113]

Nuclear Capital PG&E Forecast and Settlement Amount	2018	2019	2020
Office Furniture and Equipment	$268,000	$183,000	$100,000
Tools and Equipment	$497,000	$857,000	$644,000
DCPP Capital	$132,235,000	$108,216,000	$39,904,000
Nuclear Safety and Security	$10,300,000	$1,999,000	$0
Total	**$143,300,000**	**$111,255,000**	**$40,648,000**

MW 03 – Office Furniture and Equipment: are for costs to replace office furniture and other accessory equipment to support nuclear operations.

MWC 05 – Tools and Equipment: are for capital tools and equipment to support nuclear operations.

MWC 20 – DCPP Capital: represents most of the capital costs for operating and maintaining the DCPP. This includes the Main Generator Stator[114] Replacement Project that will upgrade the Unit 2 main generator in-phase on turbine deck to extend the stator's life to the end of the operating license in 2025. The project is forecast at $90.4 million.

MWC 3I – Nuclear Safety and Security: includes capital costs recorded in the NRCRBA relating to mandated projects by the NRC.

8.5.3. Positions of the Parties

The Settlement Agreement adopts all of PG&E's proposed O&M and capital costs under Nuclear Operations.

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[113] Amounts are shown in Appendix B of the Settlement Agreement at 9 to 13.

[114] Stator is the stationary part of the alternating current motor.

Cal Advocates originally proposed using PG&E's recorded capital costs for 2018 of $51.319 million. However, Cal Advocates also agrees to include project recovery costs totaling $76.694 million for a total of $128.025 million instead of PG&E's forecast of $143.3 million.

A4NR objects to Article 2.4.2.2 of the Settlement Agreement concerning the proposed Unit 2 Main Generator Stator Replacement Project. A4NR states that PG&E's cost-effectiveness analysis regarding the project is inadequate. A4NR adds that a memo account should be created to record DCPP costs and that any post-approval reallocation of authorized DCPP costs to the reasonable costs of DCPP shutdown and decommissioning should be restricted.

WEM proposes that DCPP be declared as a stranded asset and that it is uneconomical to continue to operate the plant. WEM also opposes the Generator Stator Replacement project stating that the project does not make financial sense. WEM proposes that DCPP costs be tracked in a memorandum account and that any relevant decision pursuant to the petition to modify D.18-01-022 be incorporated into the decision.[115]

TURN originally proposed a reduction of $25.000 million or a reduction of at least 25 percent in costs for the Stator Replacement project but as part of the settlement agreed to PG&E's proposed cost.

8.5.4. Discussion

After review of the evidence presented in this proceeding, we find the proposed O&M forecast of $357.330 million which the settling parties agreed-on is reasonable and supported by the evidence. This amount is $22.797 million less than 2017 recorded expenses of $380.127 million and is reflective of affordability

115 The petition to modify was denied in D.20-03-006.

initiatives including organization alignment and optimization, outage optimization, and implementation of various projects that reduce the need for security compensatory measures.[116] PG&E also states that it will maintain controls and mitigation of risks identified during the RAMP process. PG&E adds that all regulatory improvement actions have been completed in compliance with state and federal regulations to ensure that a core damaging event is effectively managed with minimal risk.[117]

Regarding capital costs, Article 2.4.2.2 adopts PG&E's proposed forecast for the Generator Stator Replacement Project of $14.785 million for 2018, $38.490 million for 2019, and $5.972 million for 2020 as well as other costs for the project.[118] A4NR objects to the proposed project, as does WEM which states that PG&E did not show that the proposed costs are reasonable and could not be avoided.[119] WEM also adds that this repair would last well beyond Unit 2's retirement date.

In reviewing the above arguments, we first consider that DCPP will be looked at as an operating asset for this GRC period for reasons already explained earlier in the proceeding. Thus, whatever is needed to safely and reliably operate the plant will be of primary concern. The plant's expected shutdown in 2024 and 2025 will be considered as an important factor but does not overcome the need to consider safety as the primary issue when looking at the necessity of projects and their costs. With respect to the Stator Replacement Project, PG&E's testimony

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116 Exhibit 146 at 3-45.

117 *Id* at 3-43.

118 The total project costs of $90.3 million stated in Article 2.4.2.2 consist of the forecast capital expenditures listed and construction work in progress as of December 31, 2017 as well as other costs.

119 WEM Comments at 2.

shows that the decision to undergo the project is based on an extensive inspection and evaluation of the Unit 2 main turbine generator conducted by the manufacturer.[120] The inspection revealed progressive degradation of certain components likely to lead to the eventual failure of the generator stator which could lead to an unplanned outage of 100 days or more. More importantly, failure of the generator increases safety risks associated with potential hydrogen fire at the plant. Parties opposing the project did not challenge the safety aspect of operating the plant or proposed reductions regarding the scale of the project such as omitting specific replacements or repair within the large project. Parties also did not challenge specific costs as being unreasonable. Based on the evidence and arguments presented, we find the project and settlement costs reasonable and necessary in order to continue operating DCPP safely and reliably for this GRC cycle.

We also accept the capital costs for 2019 and 2020 proposed in the settlement including PG&E's proposed modification involving Independent Spent Fuel Storage Installation (ISFSI) costs which is discussed later in this chapter. For 2018, Cal Advocates' original proposal results in a total of $128.05 million including project recovery costs. PG&E originally agreed to use 2018 recorded costs for DCPP as shown in its rebuttal testimony in Exhibit 71 subject to adjustment of excluding cancelled projects.[121]

Based on the above, we find it more reasonable to adopt PG&E's recorded costs in 2018 of $128.025 million. However, Article 3.2 of the Settlement Agreement already addresses this issue by providing that the forecast cost in

[120] Exhibit 146 at 3-25 to 3-26.

[121] Exhibit 71 at 3-9.

2018 of $143.300 million will be adjusted to reflect recorded costs in 2018. Thus, we find the settlement amount coupled with the adjustment from Article 3.2 acceptable.

For 2019 and 2020, we find it reasonable to accept the proposed capital costs of $111.255 million for 2019 and $40.648 million for 2020.

With respect to WEM's proposal to track DCPP expenses into a memorandum account, we find this to be unnecessary at this time. There are no issues regarding difficulty of forecasting DCPP costs raised in this proceeding and as discussed above, this decision will treat DCPP as being operational for this GRC cycle and issues regarding earlier closure of the plant were deferred to the petition to modify D.18-01-022. Thus, we find it unnecessary to track DCPP costs at this time based on the arguments raised by WEM.

8.6. Ratemaking and Other Issues

8.6.1. Decommissioning Reserve for Generation Assets

The settlement includes a decommissioning reserve for PG&E's generation assets which includes fossil, fuel cells, hydroelectric, and solar, which we find reasonable. Decommissioning costs for Diablo Canyon and Humboldt Bay nuclear decommissioning trusts are part of PG&E's Nuclear Decommissioning Cost Triennial Proceeding application pursuant to D.03-10-014.[122] Parties do not oppose the establishment of a decommissioning reserve for the assets mentioned above as proposed by PG&E. However, the settlement reduces PG&E's proposed hydroelectric decommissioning reserve revenue requirement for TY2020 by $8.510 million which we find appropriate to incorporate the impact of the sales of the Deer Creek and Narrows facilities.

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122 Exhibit 146 at 8-2 to 8-3. *See also* A.18-12-008.

JCCA recommends rejecting the decommissioning reserve proposals or in the alternative, reducing the annual accruals that PG&E can recover. JCCA suggests that PG&E should wait to accrue funds until assets are within 10 years of their decommissioning date. JCCA also believes that more assets than the Deer Creek and Narrows facilities will be sold rather than decommissioned.

The amount of the reserve is based on assets that PG&E currently has and while it is true that assets may suddenly be sold before they are decommissioned, it is not reasonable to assume that this would be the case absent more concrete evidence. In any case, the Settlement Agreement reduces the proposed hydroelectric decommissioning reserve revenue requirement from $18.510 million to $10.000 million, and we find that this reduction addresses the above issue for this GRC cycle and represents a fair compromise between party positions. The decommissioning reserve should also be reviewed in PG&E's next GRC cycle to determine what adjustments are needed to the decommissioning reserve amount.

8.6.2. Department of Energy (DOE) Litigation Proceeds

The settlement includes a forecast of $20.500 million per year of the Spent Nuclear Proceeds pursuant to the administrative claims procedure under the DOE.[123] The procedure is part of the settlement to reimburse PG&E for the costs of storing spent nuclear fuel at DCPP and Humboldt Bay. We find the above amount a fair compromise between the $10.500 million per year proposed by PG&E and the $25.000 million per year proposed by Cal Advocates.

[123] Exhibit 146 at 3-22 to 3-23.

8.6.3. DCPP Cancelled Capital Projects

The settlement provides cost recovery of certain cancelled projects pursuant to the DCCP retirement decision, totaling $76.694 million, which we find reasonable. The list of cancelled projects is presented in Appendix H of the Settlement Agreement. Recovery of these costs was authorized in the DCPP retirement decision. Specifically, the decision allows recovery of direct costs associated with projects recorded as of June 30, 2016 and directed PG&E to make recovery request in this GRC rather than through the advice letter process.[124]

8.6.4. Recovery of DCPP Net Book Value

The settlement authorizes PG&E to transfer the resulting balance recorded in the Diablo Canyon Retirement Balancing Account (DCRBA) to the Utility Generation Balancing Account (UGBA) or its successor. The balance for 2018 and 2019 capital additions will also be transferred to the UGBA effective January 1, 2020 while balances from 2020 to 2022 as of December 31 of each year will be transferred to the UGBA on January 1 of the following year. We have no objections regarding this proposal and find it reasonable to authorize the proposal.

8.6.5. Recovery of DCPP Long Term Seismic Program (LTSP)

The settlement includes recovery of LTSP costs of $3.800 million which parties do not oppose and which we find reasonable. LTSP costs were transferred to the Diablo Canyon Seismic Studies Balancing Account (DCSSBA) for review in PG&E's Energy Resource Recovery Account (ERRA) proceeding for proper integration of the AB 32 advanced seismic studies with the Senior Seismic Hazards Analysis Committee process (SSHAC). However, because the process is now complete, no additional costs associated with these activities will be

[124] Exhibit 146 at 8-4.

incurred[125] and so it is proper to review LTSP costs for ongoing operations costs in the GRC moving forward and to close the DCSSBA.

8.6.6. Recovery of DCPP Materials and Supplies Inventory

The settlement includes recovery of expected end of plant materials and supplies which we find reasonable because it is necessary to retain a certain level of inventory to support the DCPP's continued operation until 2024 and 2025. We also have no objections to the proposed five-year amortization schedule set forth in Article 2.4.2.7 of the Settlement Agreement.

8.6.7. Independent Spent Fuel Storage Installation (ISFSI)

The settling parties agree that ISFSI costs be treated as expense rather than capital costs for purposes of this GRC. However, ISFSI is a forecasted capital expenditure that will be completed in 2023. Therefore, ISFSI will be removed as a capital expenditure and recovered as a decommissioning expense beyond this GRC cycle. The settlement includes capital costs for ISFSI in the amount of $2.233 million. As amended by PG&E, ISFSI is removed from the 2020 capital forecast and per the above agreement, the total forecast for 2020 capital projects should be reduced by this amount. However, the settlement was amended on September 28, 2020 to correct the 2020 capital costs by removing $2.233 million from the 2020 capital forecast.

8.7. Summary

To summarize, all proposals in the Settlement Agreement and PG&E's amendment relating to Energy Supply are reasonable and should be adopted. In addition, PG&E's capital forecast for 2018 is subject to adjustment pursuant to Article 3.2 of the settlement wherein the 2018 forecast costs will be replaced with PG&E's recorded capital expenditures in 2018.

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[125] Exhibit 146 at 8-6.

9. Customer Care

This section discusses PG&E's forecast for operating expenses and capital expenditures related to PG&E's Customer Care operations. PG&E's testimony on Customer Care operations has seven chapters: 1) Customer Engagement; 2) Pricing Products and Income Qualified Programs; 3) Contact Centers Operations; 4) Customer Service Offices; 5) Metering; 6) Billing, Revenue, and Credit; and 7) Regulatory Policy and Compliance.

For its Customer Care operations, PG&E requests TY2020 forecasts of $316.435 million in expenses and $141.7 million in capital expenditures.

Expense *(in Thousands of Dollars)*		
TY2020 Forecasts *(in Thousands of Dollars)*	**Expense**	**Capital Expenditure**
Customer Engagement	$ 48,927	$ -
Pricing Products and Income Qualified Programs	$ 56,888	$ -
Contact Center Operations	$ 61,688	$ 8,241
Customer Service Offices	$ 19,304	$ 500
Metering	$ 27,660	$ 133,000
Billing, Revenue, and Credit	$ 82,969	$ -
Regulatory Policy and Compliance	$ 15,100	$ -
Total	$ 312,536	$ 141,741

In Article 2.5 of the Settlement Agreement, the settling parties agree to a TY2020 forecast of $277.5 million in expenses and $140.2 million in capital expenditures for PG&E's customer care operations. This represents a reduction of PG&E's forecasts by $35 million in expenses.

The JCCA proposes different functional allocations between gas distribution, electric distribution, and electric generation functions, resulting in different forecasts for the customer engagement, contact centers, and customer care activities. We discuss these issues in the chapter on Issues Outside the Settlement.

We now turn to a discussion of the settlement regarding each section of PG&E's customer care operations.

9.1. Customer Engagement

The Customer Engagement chapter discusses activities that include 1) providing customer support, education, and outreach, 2) providing customers with tools to better understand their energy usage as well as resources for installing distributed generation, and 3) providing account services to large commercial customers, industrial and agricultural customers, and small and medium business customers.

PG&E requests $48.9 million in TY2020 expenses for Customer Engagement activities, which is a $4.2 million increase over its 2017 recorded expenses. The requested expenses are for the following activities:

Expenses *(in Thousands of Dollars)*		
MWC	**Activities**	**PG&E's Forecast**
DK	Manage Customer Inquiries	$ 928
EL	Develop New Revenue	$ 24,628
EZ	Manage Var Cust Care Processes	$ 4,632
FK	Retain & Grow Customers	$ 878
GM	Manage Energy Efficiency- Non-Balancing Account	$ 699

IV	Provide Account Services	$ 17,162
	Total	$ 48,927

MWC DK (Manage Customer Inquiries) includes costs that support PG&E's Escalated Complaints Management team, which responds to concerns and complaints that customers file with the Commission or that were escalated to PG&E's executive offices. MWC EL (Develop New Revenue) includes costs that support PG&E's efforts to offer additional services with existing assets to generate revenues that would reduce the revenue requirement. MWC EZ (Manage Various Customer Care Processes) includes costs of activities that measure, analyze, and improve customer satisfaction, facilitate customer adoption of distribution generation technologies, and help customers understand their energy usage through energy data tools. MWC FK (Retain and Grow Customers) includes costs that support economic development efforts, including PG&E's Economic Development Rate (EDR) program, to promote local job creation and keep businesses in California. MWC GM (Manage Energy Efficiency, Non-Balancing Account) includes costs that support activities related to providing customer support, rate options, and education and outreach on clean fuel usage. MWC IV (Provide Account Services) includes costs of providing essential services to the large commercial customers, industrial and agricultural customers, and small and medium commercial customers.

In addition to the above expenses, PG&E also requests $2.5 million in MWC 2F (Build IT Apps & Infrastructure) for 2019 capital expenditures to implement the Common Customer Data Sharing Platform. The Common Customer Data Sharing Platform will provide self-service access to customer billing and energy usage data so that customers and third parties can easily share, view, and download customers' energy usage data.

9.1.1. Assembly Bill (AB) 802 Memorandum Account

In the Customer Engagement chapter, PG&E also requests to recover the costs recorded in the AB 802 memorandum accounts and to close the accounts. The AB 802 memorandum accounts record the costs PG&E incurred to comply with the requirements of AB 802. AB 802 requires utilities to maintain energy consumption data of all the buildings to which they provide service and to share that data with building owners or their authorized agents. The data allows the California Energy Commission to benchmark the energy use of buildings. In support of the benchmarking goals in AB 802, PG&E created a web portal that allows building owners and authorized agents to share energy data with the Energy Star Portfolio Manager.

PG&E forecasts that it will record \$3.1 million in expenses and \$2.2 million in capital expenditures by December 31, 2019, and requests to recover these costs. In addition, PG&E requests to recover \$700,000 in TY2020 expenses (budgeted in MWC EZ) in this GRC for continuing AB 802 compliance activities.

9.1.2. Memorandum of Understanding (MOU) between PG&E and the SBUA

PG&E also requests the Commission approve a Memorandum of Understanding (MOU) between PG&E and the Small Business Utility Advocates (SBUA). Under the MOU, PG&E will spend \$6.5 million annually to provide outreach and support services to PG&E's small and medium business customers, including connecting customers to PG&E tools, resources, programs, service, and Integrated Demand-Side Management offerings and providing a dedicated website for small and medium business customers. The MOU aligns with the MOU the Commission approved in the 2017 GRC for PG&E and SBUA. The costs for implementing the MOU are budgeted in MWC IV (Provide Account Services).

9.1.3. Settlement Agreement

The settlement agreement adopts PG&E's forecasted expenses and capital expenditures for the activities related to Customer Engagement. The settlement also adopts a stipulation between PG&E and TURN which revised PG&E's request for AB 802 compliance expenses from $700,000 to $525,000 (MWC EZ).

As for the AB 802 Memorandum Accounts, the settlement adopts PG&E's proposed cost recovery and account treatment, including the disposition of costs recorded in the accounts, the amortization period of the costs, and the closure of the accounts.

In addition, the settlement adopts the MOU between PG&E and SBUA. The settlement also adopts PG&E's proposed cost recovery mechanism for the costs PG&E commits to spend in the MOU.

9.1.4. Positions of the Parties

Cal Advocates did not oppose PG&E's forecasts for the customer engagement activities but contested PG&E's forecast of $0.878 million for MWC FK. PG&E's MWC FK account supports PG&E's efforts to retain and grow customers, which includes PG&E's Economic Development Rate program. Cal Advocates opposed funding PG&E's customer retention and growth with ratepayer money, arguing that shareholders should fund these activities. Cal Advocates also argued that, because EDR is a rate design issue, EDR costs should be considered in the Phase 2 proceeding rather than this current proceeding.[126] TURN supported Cal Advocates' recommendations.[127] In

[126] Exhibit 257 at 5 to 6.

[127] Exhibit 177 at 3.

response, PG&E explained that the forecasted costs only support the administration and implementation of the EDR program and not any other customer retention and growth programs. PG&E argued that the administrative costs of EDR are appropriately recovered through the Phase 1 GRC and noted that its previous GRC Phase 1 (2017 GRC) approved EDR administrative costs that were of similar magnitude as the costs requested in this GRC.[128]

The parties did not contest the costs that PG&E forecasts will be recorded in the AB 802 memorandum accounts. However, Cal Advocates recommended that the balance recorded in the AB 802 memorandum accounts be amortized over a three-year period instead of the one-year period PG&E proposed. Cal Advocates argued that a three-year period is consistent with the timeframe over which the costs were incurred. PG&E opposed Cal Advocates' recommendation, arguing that the impact of a one-year amortization period on rates is small, increasing electric rates by only $0.000014/kilowatt-hour, or 0.007 percent, and gas rates by $0.00013/therm, or 0.008 percent.[129] PG&E also noted that it typically amortizes approved memorandum account balances over a one-year period through its Annual Electric True-up and Annual Gas True-up advice letters.

Although parties did not contest the incurred AB 802 costs PG&E recorded in the memorandum accounts, TURN contested PG&E's TY2020 forecast of $700,000 in MWC EZ for expenses to maintain the benchmarking tools used to comply with Assembly Bill 802. These benchmarking tools include maintaining a web portal which enables building owners to share energy usage data with

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[128] Exhibit 93 at 2-10 to 2-14.

[129] Exhibit 93 at 2-5.

their authorized agents. TURN recommended a reduction of $314,000 to PG&E's forecasted $700,000 in MWC EZ expenses, arguing that PG&E overestimated its staffing needs for the project since the web portal was already built.[130] On October 1, 2019 during hearings, TURN and PG&E presented a stipulation, in which they agreed that PG&E's forecast should be amended to $525,000, a reduction of $175,000.[131] The settlement adopts the stipulation's $525,000 as the forecasted expenses to maintain the AB 802 benchmarking tools.

9.1.5. Discussion

We reviewed the cost forecasts and proposals presented in the settlement and considered them to be reasonable. The settlement adopts PG&E's expense forecasts for MWC FK, which Cal Advocates originally contested. Cal Advocates argued that the EDR implementation costs budgeted in MWC FK should be considered in the GRC Phase 2 proceeding because EDR issues are rate design issues. It is reasonable to consider the EDR implementation costs in this proceeding since we are not considering EDR policies or issues but only the recovery of its implementation costs. As PG&E noted, similar EDR implementation costs were approved in the last PG&E Phase 1 GRC (TY 2017). We therefore consider it reasonable and adopt the settlement's forecast in MWC FK for EDR implementation costs.

The settlement adopts the costs PG&E forecasted in the AB 802 Memorandum Accounts. We reviewed the costs recorded in these accounts. Most of these costs are used to build a web portal to improve data analysis, collection, and compilation, which helps PG&E further the goals of AB 802.[132] It

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130 Exhibit 177 at 4.

131 Hearing Room Exhibit 97.

132 Exhibit 92 at 2-40 to 2-41.

is therefore reasonable to adopt the settlement's proposal to approve these costs. Thus, we approve the costs recorded in the AB 802 Memorandum Accounts, as of December 31, 2019, for recovery.

The settlement also adopts PG&E's proposed one-year amortization period of the balance recorded in the AB 802 memorandum accounts. The estimated rate impact of PG&E's proposed one-year amortization period, 0.007% increase in electric rates and 0.008% increase in electric rates, is small, and PG&E has used a one-year amortization period for other similar memorandum accounts. Therefore, it is reasonable to adopt a one-year amortization period for the AB 802 memorandum accounts, as proposed by the settlement.

The settlement's adoption of the stipulation between TURN and PG&E for the AB 802 compliance expenses is reasonable in light of the record. The stipulation, which reduces PG&E's forecasted expenses to maintain AB 802 benchmarking tools by $175,000, represents a fair compromise between the parties' initial positions and addresses TURN's original concerns that PG&E may have overestimated staffing needs. We therefore consider it reasonable and adopt the stipulated forecast of $525,000 for AB 802 compliance expenses.

Finally, we also adopt the MOU between PG&E and SBUA. The MOU promotes the collaboration between PG&E and its small and medium business customers by encouraging PG&E to help these customers manage their energy usage. The settlement adopts PG&E's proposal of recovering from ratepayers the $6.5 million in annual expense PG&E expects to incur from the MOU. In PG&E's 2017 GRC, the Commission approved a MOU with terms that are similar to the current MOU and a cost recovery mechanism for the MOU that is similar to the one adopted in the settlement agreement. Therefore, we find the terms of the MOU and PG&E's proposed recovery of costs for the MOU, as adopted in the settlement, to be reasonable and approve them.

9.2. Pricing Products and Income Qualified Programs

The Pricing Products and Income Qualified Programs chapter discusses activities that support rate program and rate structure changes, as well as Income Qualified Programs that are not funded by Public Purpose Program funds or Greenhouse Gas (GHG) revenues. The Income Qualified Programs include the Natural Gas Appliance Testing and new Disadvantaged Communities activities.

PG&E requests $58.6 million in TY2020 expenses, which is a $22.4 million, or 62 percent, increase over its 2017 recorded expenses for activities related to Pricing Products and Income Qualified Programs. The requested expenses are for the following activities:

2020 Expenses *(in Thousands of Dollars)*		
MWC	**Activities**	**PG&E's Forecast (as filed)** (A)
EZ	Manage Var Cust Care Processes	$ 50,453
GM	Manage Energy Efficiency - NonBA	$ 7,935
	Total	$ 58,388

MWC EZ (Manage Various Customer Care Processes) includes the costs of residential rates implementation, non-residential rates implementation, and residential rate reform activities (activities related to transitioning customers to Time-of-Use (TOU) rates). MWC GM (Manage Energy Efficiency, Non-Balancing Account) includes the costs for the Natural Gas Appliance Tests.

The majority of the forecasted TY2020 expenses in this chapter are for ongoing costs of residential rate reform activities. The costs for these activities have been recorded in the Residential Rate Reform Memorandum Account (RRRMA) since 2015. PG&E is not requesting recovery of the costs recorded in the RRRMA from 2015-2019, or expenses incurred prior to TY2020. In this GRC, PG&E requests cost recovery for the ongoing residential rate reform activities and the Statewide Marketing, Education, and Outreach (Statewide ME&O) activities that PG&E expects to incur during this GRC cycle (2020-2022).

As part of the residential rate reform, the Statewide ME&O program "optimize(s), align(s), and integrate(s) electricity-related customer engagement campaigns with other Commission programs"[133] for the transition of residential customers to TOU rates. Statewide ME&O costs support activities that are mandated by and supervised by the Commission. PG&E requests that the Statewide ME&O costs, including costs that PG&E incurred in the 2017 GRC and costs that PG&E will incur in this GRC, be recovered through a new two-way balancing account, and that the costs recorded in the two-way balancing account be recovered through PG&E's Annual Electric True-up (AET) advice letters.[134] For TY2020, PG&E forecasts $20.0 million in expenses for the Statewide ME&O contract activities.

9.2.1. Settlement Agreement

The settlement agreement adopts PG&E's forecasted expenses for the Income Qualified Programs.

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133 Exhibit 91 at 3-14.

134 *Ibid.*

The settlement also adopts a stipulation PG&E reached with TURN on two issues TURN contested. First, the stipulation adopts PG&E's forecasted expenses for the Natural Gas Appliance Testing program, one of PG&E's Income Qualified Programs. Also, the stipulation reduces PG&E's forecasted expenses for the non-residential rates implementation by $1.5 million.

Finally, the settlement agreement sets forth a series of modifications to PG&E's proposed treatment and recovery of residential rate reform costs. First, PG&E would continue to record the actual residential rate reform implementation costs and Statewide ME&O costs incurred in the 2020 GRC cycle in the existing RRRMA. Cal Advocates may audit the RRRMA. Second, PG&E would remove $30.896 million in revenue requirement from the GRC. The $30.896 million in costs reflects the removal of $10.896 million for rate reform implementation activities and $20 million for Statewide ME&O activities. Third, PG&E would be authorized to collect in 2020 rates the $30.896 million, the same amount removed from the TY 2020 GRC revenue requirement, through PG&E's AET advice letters. Through the AET advice letters, PG&E would also be able to collect $10.896 million in rate reform implementation costs and $10 million in Statewide ME&O activities in 2021 rates, as well as $10.896 million in rate reform implementation costs in 2022 rates. These revenues, collected in rates through the AET, are subject to a refund through a reasonableness review of the RRRMA costs. Fourth, at the end of the 2020 GRC cycle, PG&E would seek recovery of the actual costs recorded in the RRRMA through a reasonableness review, either through an application or Rulemaking (R.)12-06-013. Through the reasonableness review, PG&E's actual recorded costs would be trued-up with the revenue collected in rates through the AET advice letter filings. Finally, the costs recorded in the RRRMA during the 2020 GRC cycle would not be subject to refund if the Commission finds that PG&E has demonstrated during the reasonableness review that the costs were "incremental, verifiable, reasonable, and consistent with Commission requirements."[135]

As a result, the settlement adopts a forecast of $25.786 million in expenses for rate support activities and Income Qualified Programs. The table below presents a comparison of PG&E's forecasts and the forecasts in the settlement.

2020 Expenses *(in Thousands of Dollars)*					
MWC	**Activities**	**PG&E's Forecast (as filed)** (A)	**PG&E's Updated Forecast**** (B)	**Settlement** (C)	**Difference** (C) - (B)
EZ	Manage Var Cust Care Processes	$ 50,453	$ 48,950	$ 17,951	$ (31,000)
GM	Manage Energy Efficiency – Non-BA	$ 7,935	$ 7,935	$ 7,935	$ -
	Total	$ 58,388	$ 56,885	$ 25,886	$ (31,000)
** PG&E's Updated Forecast includes labor escalation adjustments, concessions PG&E made during Rebuttal Testimony and adjustments PG&E made as a result of reaching a stipulation with the parties. *Response of PG&E to ALJs' Ruling, Dated May 20, 2020, Updated Appendix B, Page 5.*					

9.2.2. Positions of the Parties

Initially, Cal Advocates opposed PG&E's proposal to replace the RRRMA with a two-way balancing account, arguing that the costs in a balancing account do not receive the reasonableness review that costs in a memorandum account do.[136] National Diversity Coalition (NDC) agrees with Cal Advocates.

135 Joint Motion for the Settlement Agreement at 34.

136 Exhibit 257 at 10.

TURN contested PG&E's forecasted expenses for non-residential rates implementation activities, which include planning and implementing rate plan changes for commercial industrial and agricultural customers. PG&E forecasts TY2020 expenses of $9.8 million, an increase of $3.4 million, or 52 percent, compared to 2017 recorded costs, and attributes the increase to activities related to transitioning non-residential customers to new mandatory TOU periods and Peak-Day Pricing (PDP) event hours.[137] TURN recommended that PG&E's forecasted expenses remain at the 2017 recorded level of $6.5 million.[138] TURN argued that PG&E's forecast is unreasonable because 1) PG&E's transition of non-residential customers to new rate plans has been declining in the data recorded from 2012 to 2018, 2) the transition of the new PDP event hours was delayed until 2021, and 3) the transition of customers to new PDP event hours, which PG&E plans to do during this GRC cycle, should not be as complex and incur more costs than in the 2017 GRC cycle when PG&E transitioned customers from tiered rate plans to TOU rate plans. In rebuttal, PG&E recognized the delay for the implementation of new PDP hours and reduced its forecast by $163,000.[139] Even though the transition to new PDP hours is less complex, PG&E posited it will incur more costs because the amount of customers it plans for rate transition is about ten-fold higher than in 2017.

In addition, TURN opposed PG&E's forecasted expenses of $7.9 million for Natural Gas Appliance Testing, which is an increase of 109% over 2017 recorded costs of $3.8 million. The Natural Gas Appliance Testing program helps ensure the safety of participating customers by hiring contractors to perform a natural

[137] Exhibit 91 at 4-12 to 4-13.

[138] Exhibit 177 at 4 to 6.

[139] Exhibit 93 at 4-17 to 4-19.

gas appliance test to ensure that appliances are working properly. TURN argued that PG&E overestimated its labor costs, which PG&E forecasted to increase by 70 percent. TURN stated that the average of PG&E's forecasted range of labor rates is 25 percent higher than the average of the actual range of labor rates received from contractor bids. TURN recommended that the labor cost increase by 45 percent instead, which would result in a $1 million decrease to PG&E's forecast, or a TY2020 forecast of $6.9 million. In response, PG&E argued that TURN's set of contractor rates did not account for the different level of effort and material costs required by different projects, and explained that its TY2020 forecast is derived based on contract prices by region for labor, time to install, and material costs that were escalated using a weighted 2017 Consumer Price Index (CPI) rate of 2.14 percent.[140]

On October 1, 2019 during hearings, TURN and PG&E presented a stipulation agreeing to a revised forecast of $8.165 million for PG&E's non-residential rates implementation activities, which is a $1.5 million reduction to PG&E's forecast. Under the stipulation, TURN and PG&E also agree to PG&E's forecast of $7.935 million for the Natural Gas Appliance Testing program.[141] The settlement adopts this stipulation between TURN and PG&E.

9.2.3. Discussion

The stipulation reached between PG&E and TURN, which the settlement adopts, contains forecasted expenses that are reasonable. The revised forecast for the non-residential rate implementation activities, which is $1.5 million less than PG&E's forecast, represents a compromise of the parties' positions and addresses

140 Exhibit 20 at 3-28.

141 Exhibit 98.

the concerns of both parties. Even though the rate transition PG&E must perform in 2020 (new PDP event hours) is less complex than the rate transition it performed in 2017 (from tiered to TOU rate plans), PG&E expects to transition ten times more customers in 2020 than in 2017. The settlement's forecast of $8.165 million for the non-residential rate implementation activities is therefore reasonable and adopted. As for the Natural Gas Appliance Testing Program, the stipulation adopted PG&E's request. PG&E supported its request sufficiently with a forecast that takes into account differences in labor rates based on region, time to install, and material costs. PG&E also addressed TURN's concerns by explaining that the variance in forecasted labor costs and costs from actual contractor bids is due to regional differences in labor rates, effort and time to install a project, and material costs. Thus, adopting PG&E's forecast, as set forth in the settlement, is reasonable in light of the record.

The settlement proposes significant modifications to PG&E's proposed cost recovery of residential rate reform activities. The settlement proposes that PG&E collect in rates the forecasted costs of the rate reform implementation and Statewide ME&O activities, record the actual costs in the RRRMA, and true-up the revenue collected in rates for the rate reform and Statewide ME&O activities with the costs recorded in the RRRMA during a reasonableness review at the end of the GRC cycle. Under this approach, shareholders do not have to advance three years of rate reform and Statewide ME&O costs, which are significant when these costs are added together over the GRC cycle. Ratepayers will only pay for the actual costs of the rate reform and Statewide ME&O activities, because PG&E will reconcile the revenue it collected with the actual costs recorded in the RRRMA. Furthermore, these costs will be reviewed for reasonableness to ensure that ratepayers only pay for costs that are reasonably incurred. Thus, the settlement protects the interests of both ratepayers and shareholders in that ratepayers will pay PG&E only for the actual costs of the activities, which PG&E must demonstrate are reasonably incurred, while shareholders do not have to advance the entire costs of the residential rate reform activities for a three-year GRC cycle. Thus, the cost recovery mechanism for the rate reform and Statewide ME&O activities is reasonable, and we adopt it.

9.3. Contact Centers

The primary goal of the Contact Centers Operations (CCO) is to provide timely and responsive support to PG&E's customers for emergencies, payment inquiries, technical questions, and energy-related services and programs for the four contact centers that PG&E is operating.

The CCO department requests $63.9 million in TY2020 expenses for the operation of PG&E's contact centers, which is a $1.4 million, or 2.1 percent, lower than its 2017 recorded expenses. The requested TY2020 expenses are for the following activities:

Expenses *(in Thousands of Dollars)*		
MWC	**Activities**	**PG&E's Forecast (as filed)** (A)
DK	Manage Customer Inquiries	$ 57,682
IS	Bill Customers	$ 260
JV	Maintain IT Apps & Infrastructure	$ 6,000
	Total	$ 63,942

MWC DK (Manage Customer Inquiries) includes the general expenses for the CCO, except the expenses associated with supporting the SmartMeter

Opt-Out Program. MWC IS (Bill Customers) includes the expenses the CCOs incur for supporting the SmartMeter Opt-Out Program. MWC JV (Maintain IT Applications and Infrastructure) includes expenses associated with the IT projects supporting the CCOs.

The CCO department also requests a capital expenditure forecast (MWC 2F) of $1.1 million in 2018, $3.9 million in 2019, $8.2 million in 2020, $8.3 million in 2021, and $8.3 million in 2022.[142] The forecasted capital expenditures from 2018 to 2022 pay for IT projects that support PG&E's contact centers. These IT projects include Contact Center 2020 (Salesforce Phase 1), 2019-2020 Salesforce Phase 2 and 3, and additional web and telephone self-service enhancements. The Salesforce Phase 1 project unifies the various computer systems into one system for customer representatives so that they can access all necessary information in one place during customer transactions. The Salesforce Phase 2 and 3 projects enhance customer self-service functions over the web by enabling customers to contact PG&E through additional channels, such as a chatbot or a live chat. These projects also integrate the web system with the phone system so that customers can access both systems seamlessly. In addition, these projects enable customer representatives to handle customer inquiries from home.

9.3.1. Settlement Agreement

The settlement adopts a stipulation between TURN and PG&E in which the parties agreed on a revised project timeline and revised forecasted expenses and capital expenditures for the Salesforce Phase 2 and Phase 3 projects. Other

[142] Exhibit 91 at 4-1 to 4-2.

than the Salesforce Phase 2 and Phase 3 projects addressed in the stipulation, the settlement adopts all of PG&E's forecasted expenses for the CCOs.

9.3.2. Positions of the Parties

Besides TURN, parties did not oppose PG&E's forecasted costs for the CCOs. TURN opposed PG&E's forecasted $8.1 million in expenses (MWF JV) and $12.2 million in capital expenditures (MWF 2F) for the Salesforce Phase 2 and 3 projects because, according to TURN, PG&E cannot estimate the benefits these projects bring and cannot demonstrate that the benefits of the project outweigh the costs.[143] In rebuttal, PG&E provided additional analyses to estimate the benefits of the Salesforce Phase 2 and 3 projects. PG&E estimates that these projects will provide a benefit of $8.4 million per year beginning in 2021 due to reduced customer call volumes and reduced employee absenteeism.[144]

TURN and PG&E submitted a stipulation during hearings on October 1, 2019 regarding the Salesforce Phase 2 and 3 projects.[145] In the stipulation, TURN and PG&E agreed to defer the Salesforce Phase 2 and 3 projects until 2020 (instead of beginning in 2019), and to revise the workplan so that the projects are completed in 2022. In addition, TURN and PG&E agreed to reduce PG&E's forecasted TY2020 expenses by the $2.213 million of savings PG&E expects to achieve through these projects. The stipulation also revised the forecasted capital expenditure to $4.074 million per year from 2020 to 2022, which totals to $12,222, a reduction of $17.649 million compared to the sum of

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143 Exhibit 177 at 8 to 10.

144 Exhibit 93 at 4-6.

145 Hearing Exhibit 98.

PG&E's original forecasts from 2018-2022. The table below shows a comparison of PG&E's original requests and the revised forecasts in the stipulation.

Salesforce Phase 2 and 3 Projects *(in Thousands of Dollars)*						
MWC 2F (Capital)	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**
PG&E's Forecast	$1,119	$3,864	$8,241	$8,348	$8,299	$29,871
Stipulation	$0	$0	$4,074	$4,074	$4,074	$12,222
MWC JV (Expense)	**2020**					
PG&E's Forecast	$2,743					
Stipulation	$489					

9.3.3. Discussion

The settlement adopts PG&E's forecasts supporting the CCOs. After reviewing the unopposed PG&E forecasts, we determine them to be reasonable and adopt them.

The settlement also adopts the revised forecasts in the stipulation between TURN and PG&E for the Salesforce Phase 2 and 3 projects. The revised forecasts adopted in the stipulation are a compromise of TURN's and PG&E's original positions. The stipulation addresses TURN's concerns about the net benefits of the Salesforce Phase 2 and 3 projects by reducing PG&E's forecast costs by the estimated savings PG&E accrues from the projects, while still allowing PG&E to pursue these projects. The revised forecasts adopted in the stipulation are thus reasonable in light of the record, and we adopt them.

9.4. Customer Service Offices

The Customer Services Offices department operates and manages PG&E's Customer Services Offices (CSO). PG&E operates 75 CSOs, which are offices that provide face-to-face service to customers, including processing customer payments and certain non-payment transactions.[146]

The CSO department requests $19.3 million in TY2020 expenses, which is $1.2 million, or 7 percent, more than its 2017 recorded expenses. The requested expenses are for the following activities:

Expenses *(in Thousands of Dollars)*		
MWC	**Activities**	**PG&E's Forecast**
DK	Manage Customer Inquiries	$ 1,888
EZ	Manage Various Customer Care Processes	$ 6,689
IU	Collect Revenue	$ 10,727
	Total	$ 19,304

MWC DK (Manage Customer Inquiries) includes the costs to provide customer support for non-payment transactions at the CSOs and includes funding for activities outlined in the MOU with CforAT.[147] MWC EZ (Manage Various Customer Care Processes) includes the costs for various customer service processes and activities at the CSOs. MWC IU (Collect Revenue) includes the costs to support the payment processing activities at the CSOs.

The CSO department also requests a capital expenditure forecast (MWC 21) of $0.5 million per year from 2018 to 2022, primarily to replace equipment due to wear and tear.

9.4.1. CSO Closures

PG&E proposes to close 17 of its 75 CSOs. PG&E explained that transaction volumes at all CSOs have decreased in recent years, as transactions

[146] Exhibit 91 at 5-1.

[147] The MOU between PG&E and CforAT is further discussed in Section 9.4.2 below.

performed in the CSOs can be conducted over the phone, mail, online, or at PG&E's Neighborhood Payment Centers (NPC). According to PG&E, the 17 CSOs PG&E proposes to close have declining transaction volume and an NPC is located within a three-mile radius of each of these CSOs. PG&E also considers other factors in determining which CSOs it proposes to close, including the percentage of California Alternative Rates Energy (CARE) customers who make payments exclusively at a CSO.[148]

The proposed closures would result in a savings of $14.2 million: $3.3 million in annual labor costs; $3.2 million annually for five-years of operational and capital expenses, and approximately $7.7 million from the sale of PG&E-owned CSO locations.[149] These savings are not included in PG&E's TY2020 forecast. If PG&E's proposal is adopted, PG&E would reduce its revenue requirement for CSO and Real Estate beginning in 2021.[150]

9.4.2. MOU with the CforAT

PG&E requests approval of its MOU with the CforAT. PG&E states that the MOU improves customer accessibility to PG&E services at the CSOs, at other PG&E facilities, and through other communication channels. Under the MOU, PG&E will spend the equivalent of $1.3 million per year from 2020-2022 (a total of $3.9 million) on activities to improve customer accessibility, issue an annual report on activities and spending to promote accessibility, employ a Disability Access Coordinator who will coordinate strategies to improve accessibility, and

[148] Exhibit 91 at 5-3.

[149] Exhibit 91 at 5-10.

[150] *Ibid.*

meet with CforAT to discuss accessibility spending at the beginning of every year.[151]

9.4.3. Settlement Agreement

In the settlement agreement, TURN, Cal Advocates, and CUE agree to have PG&E close only 10 of the 17 CSOs it originally proposed to close. PG&E will propose the 10 CSOs to close, file a Tier 1 advice letter to close the CSOs, and comply with the customer notice requirements in D.07-05-058 prior to the closure of any CSOs.

L. Jan Reid opposes the settling parties' proposal, noting that the settlement did not indicate which CSOs PG&E would close and whether and how PG&E would consider the demographic characteristics of the people using the CSOs when selecting the CSOs to close.[152]

The settlement also adopts all of PG&E's forecasts and proposals, including the recovery of costs associated with PG&E's MOU with CforAT.

9.4.4. Positions of the Parties

Cal Advocates, TURN, CUE and L. Jan Reid opposed PG&E's proposal to close 17 of its 75 CSOs. Cal Advocates argued that the CSOs PG&E proposed to close are in areas with large populations of low-income customers who generally do not transition as quickly as the general population to using technology to perform transactions for utility services. Cal Advocates also criticized PG&E's closure selection criteria for not including metrics pertaining to low-income and disabled customers.[153] Cal Advocates proposed that, prior to any CSO closures, PG&E should conduct a CSO Curtailment Pilot Program that reduces the hours

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[151] Exhibit 91 at 5-12.

[152] Comments of L. Jan Reid on the Settlement Agreement at 11 to 12.

[153] Exhibit 257 at 16 to 18.

of operations at four CSOs. TURN noted that 5 percent of customers that PG&E surveyed cannot make payments other than at the CSOs and recommended that CSOs that are more than 21 miles away from the nearest PG&E office should not be closed.[154] CUE was concerned that closure of the CSOs would unduly harm low-income and disabled customers who have difficulty in conducting transactions over the internet or phone.[155] L. Jan Reid argued that the closure of the CSOs disproportionately affects low-income, elderly, and Hispanic/Latino customers. L. Jan Reid noted that 62 percent of customers using the targeted CSOs have annual incomes lower than $50,000, 38 percent are Hispanic/Latino, 30 percent are 65 years of age and older, and 22 percent have a disability.[156]

In response, PG&E argued that customers can make cash payments at NPCs, one of which is available within three miles of every CSO PG&E proposed to close and that only five of the 17 CSOs PG&E proposed to close are in CPUC-defined disadvantaged communities.[157] In rebutting Cal Advocates' proposed CSO Curtailment Pilot Program, PG&E argued that the Commission has previously approved CSO closures for PG&E, as well as several other IOUs, without ordering the utility to first reduce the CSOs' hours of operation. PG&E stated that it conducted 1,305 in-person surveys at 18 CSOs to examine the impacts of CSO closures on low-income, elderly, and disabled customers, similar to studies the Commission previously ordered utilities to conduct prior to closing CSO.[158] In response to Cal Advocates' and TURN's concerns about the metrics

[154] Exhibit 276 at 30 to 41.

[155] Exhibit 61 at 38 to 47.

[156] Exhibit 56 at 8 to 9.

[157] Exhibit 93 at 5-23.

[158] Exhibit 93 at 5-12 to 5-13.

PG&E used in determining the CSO closures, PG&E stated that it considered factors that include the percentage of CARE customers that use the CSOs and whether there are at least two NPCs within two miles of the CSOs.[159]

9.4.5. Discussion

We share L. Jan Reid's concerns that the proposal set forth by the settlement parties did not indicate the CSOs PG&E will close and the criteria PG&E will consider in selecting the CSO for closure. Even though PG&E indicates that 95 percent of the people it surveyed has the capability to conduct utility transactions with a method other than in person,[160] we are concerned with the impact a CSO closure may have on the 5 percent of people who cannot perform utility transactions other than in person. In particular, we are concerned that these people may be part of the more vulnerable portion of the population, since a majority of the surveyed CSO users are low income customers. Without knowing the exact CSOs PG&E will close, we cannot determine how easily accessible a NPC is for the 5 percent of CSO users who can only perform utility transactions in person, even though there is a NPC within 3 miles of a closed CSO.

Thus, we modify the settling parties' proposal and direct PG&E to file a Tier 3 Advice Letter with Energy Division to specify the CSOs PG&E proposes to close and the amount of savings PG&E will achieve through the CSO closures. In the advice letter, PG&E shall provide the previous two years of data for the selection criteria PG&E originally proposed to select closures, which include: 1) Declining transaction volume; 2) A minimum of two Neighborhood Payment

[159] Exhibit 93 at 5-13 to 5-14.

[160] Exhibit 93 at 5-6.

Centers (NPC) available within a three-mile radius of the CSO; 3) Low non-payment transaction volume; 4) Availability of public transportation within one mile from the CSO to the nearest NPC; 5) The percentage of California Alternative Rates for Energy (CARE) customers; and 6) The percentage of cash-only payments made by CARE customers. PG&E should consider closing up to ten CSOs in a staggered manner, so that not all CSOs are closed at the same time. Through this process, the Commission may modify the amount of CSO locations PG&E may close.

In addition, similar to D.98-07-077 in which the Commission directed Southern California Edison to provide notices to customers prior to any office closures,[161] we will also set similar notification requirements for PG&E. Specifically, we direct PG&E to:

1. Provide Notices of Proposed Office Closures by mail, posting, and published notices. All notices must be multilingual and should include prominent statements regarding the proposed office closures and the Commission's 800-telephone number. PG&E shall provide notice of the closure sixty days prior to filing the advice letter.
2. Compile customer responses to the notice and include these responses with the advice letter

After reviewing the settlement's forecasts for the Customer Service Offices department, other than the proposed CSO closures which we modify as described above, we consider the settlement's forecasts and PG&E's MOU with CforAT, as well as the proposed funding for the MOU, to be reasonable and adopt them.

[161] D.98-07-077 at 14 to 15 and Ordering Paragraph 4.

9.5. Metering

PG&E's metering program manages PG&E's ten million gas and electric meters and provides on-the-field meter services such as manual meter reading, meter installation, and meter maintenance. The metering program consists of two departments: Metering Services and Engineering (MS&E) and Field Meter Operation (FMO).[162] The MS&E department oversees PG&E's meter maintenance and manages meter asset strategy. The MS&E department is also responsible for managing meter and module purchases, meter vendors, meter plant operations, meter engineering support, and meter data information and reporting.[163] The FMO provides field meter work related to electric meters and gas modules, which includes timely and accurate manual meter reading, electric meter and gas module installations, electric meter and module maintenance, in-field testing, troubleshooting and remediation.[164]

The metering program requests $27.7 million in TY2020 expenses, which is a $1.0 million lower than its 2017 recorded expenses. The requested expenses are for the following activities:

Expenses *(in Thousands of Dollars)*			
MWC	**Activities**	**PG&E's Forecast**	**PG&E's Updated Forecast****
AR	Read and Investigate Meters	$ 9,985	$ 9,984
DD	Provide Field Service	$ 688	$ 687
EY	Change/Maintenance Used Electric Meters	$ 8,812	$ 8,800

[162] Exhibit 91 at 6-1.

[163] Exhibit 91 at 6-5.

[164] Exhibit 91 at 6-7 to 6-8.

EZ	Manage Various Customer Care Processes	$ 220	$ 220
HY	Change/Maintenance Used Gas Meters	$ 6,648	$ 6,637
IU	Collect Revenue	$ 1,307	$ 1,307
	Total	$ 27,660	$ 27,635
** PG&E's Updated Forecast includes labor escalation adjustments, concessions PG&E made during Rebuttal Testimony and adjustments PG&E made as a result of reaching a stipulation with the parties. *Response of PG&E to ALJs' Ruling, Dated May 20, 2020, Updated Appendix B, Page 5.*			

MWC AR (Read and Investigate Meters) includes the costs of dedicated meter readers, the field resources used to perform manual meter reading, as well as the administrative and clerical support for these activities. MWC DD (Provide Field Service) includes the costs of meter activities associated with electric turn-ons and shut-offs initiated by customers. MWC EY (Change/Maintenance Used Electric Meters) includes the costs of meter activities associated with electric meter preventive maintenance, electric meter corrective maintenance, meter programming, meter network maintenance, electric meter accuracy testing, and the associated staff support for these activities. MWC EZ (Manage Various Customer Care Processes) includes the costs of meter activities associated with SmartMeter Opt-Out program oversight and the costs of supplemental utility meter engineering support. MWC HY (Change/Maintenance Used Gas Meters) includes the costs of meter activities associated with gas meter preventive maintenance, gas meter corrective maintenance, and the associated staff support for these activities. MWC IU (Collect Revenue) includes the costs of meter activities that are focused on the detection, investigation, and resolution of customer energy theft and the costs of the field employees, systems, and staff support to perform these activities.

The metering department also requests a capital expenditure forecast of $133.8 million for 2018, $134.3 million for 2019, and $133.0 million for 2020. The requested capital expenditures are for the following activities:

Capital Expenditure *(in Thousands of Dollars)*				
MWC	**Activities**	**2018**	**2019**	**2020**
5	Tools and Equipment	$ 350	$ 361	$ 244
21	Miscellaneous Capital		$ 3,620	$ 3,046
25	Install New Electric Meters	$ 50,802	$ 61,575	$ 55,116
74	Install New Gas Meters	$ 82,667	$ 67,911	$ 74,593
2F	Built IT Apps and Infrastructure		$ 832	
	Total	$ 133,819	$ 134,299	$ 133,000

MWC 5 includes the tools and equipment used to perform all field metering, meter maintenance, meter repair, and accuracy testing activities. MWC 21 includes the costs of the hardware, software, licensing, technical support, facilities management, project management, and installation associated with the Radio Frequency Identification (RFID) technology project.[165] MWC 25 includes the costs of new electric meter purchases due to customer growth, replacement of failed units, and the associated installation labor used to perform electric meter installations, exchanges, removals, and retirements. MWC 74 includes the costs of new gas meter and module purchases due to customer growth, replacement of failed units, and the associated installation labor used to

[165] The RFID project helps PG&E improve meter inventory management. *See* Exhibit 91 at 6-13.

perform electric meter installations, exchanges, removals, and retirements. MWC 2F includes the costs of executing the MCF Gas Meter IT Project.[166]

9.5.1. Settlement Agreement

The settling parties adopt all of PG&E's forecasts for the Metering program

9.5.2. Positions of the Parties

Prior to the settlement, the only category of metering expenses in dispute was PG&E's forecasted expense for meter reading (MWC AR). TURN recommended a reduction of $2.1 million to PG&E's forecasted TY2020 expense for meter reading (MWC AR). Because PG&E's forecasted number of meter reads is 43 percent less than the recorded 2017 number, TURN proposed that the TY 2020 expense should also be 43 percent less than the 2017 recorded costs.[167] TURN's proposed forecast was $7.9 million, or $2.1 million less than PG&E's forecast.

PG&E argued that, as the number of meter reads decreases over time, the average cost per meter read increases because of inflationary increases and increases in the average travel time required to perform an individual meter read.[168] PG&E also explained that the overhead costs for the meter reads are spread over fewer reads. PG&E noted that in 2008, at the beginning of the SmartMeter deployment, PG&E manually read an average of 9.15 million meters at an average cost of $0.84 per meter read.[169] In 2017, PG&E manually read

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[166] The MCF Gas Meter Project, which is sponsored by PG&E's Information Technology organization, allows PG&E to collect customers' gas usage data through a new "gas SmartMeter module.". *See* Exhibit 91 at 6-17.

[167] Exhibit 177 at 10 to 11.

[168] Exhibit 93 at 6-7 to 6-8.

[169] *Ibid*.

1.91 million meter at an average cost of $5.71 per meter read.[170] For 2020, PG&E forecasts that it will manually read 1.10 million meters at an average cost of $9.09 per meter read.[171] PG&E argued that, because the average cost of meter reads has increased over time, the total cost of performing the meter reads does not decrease by the same proportion as the number of meter reads. PG&E further explained that it derived its TY2020 forecast for meter reading by considering the 42.6 percent reduction in manual meter reads and applying an escalation, which resulted in a 17 percent net reduction in the forecast compared to 2017 recorded costs.[172]

9.5.3. Discussion

After reviewing the settlement's forecasts for the Metering program, we consider them to be reasonable and adopt them. PG&E's forecast for the metering reading expenses, as adopted in the settlement, is reasonable because PG&E's forecast takes into account the reduced number of meter reads, the increasing average costs of meter reads, and escalation increases due to inflation.

9.6. Billing, Revenue, and Credit

The Billing, Revenue, and Credit (BRC) chapter discusses activities related to processing billing exceptions, issuing customer bills and notices, processing customer payment, credit collection activities, and reporting revenue. The BRC team contains three organizations for which PG&E is requesting cost recovery: Revenue Operations; Credit Policy and Operations; and Billing Operations. The Revenue Operations organization consists of four departments: Printing and Bill Presentment; Revenue and Statistics; Customer Revenue Processing; and

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170 *Ibid*.

171 *Ibid*.

172 Exhibit 93 at 6-8.

Enterprise Revenue Strategy. The Credit Policy and Operations department consist of two departments: Credit Operations and Broken Lock. The Billing Operations department consists of four departments: Complex Billing; Billing Operations Exceptions; Business Delivery; and Billing Systems and Analytics.

The BRC department requests $85.3 million in TY2020 expenses, which is $1.8 million, or 2 percent, lower than its 2017 recorded expenses. The requested expenses are for the following activities:

Expenses *(in Thousands of Dollars)*			
MWC	**Activities**	**PG&E's Forecast**	**PG&E's Updated Forecast**** (B)
AR	Read and Investigate Meters	$ 758	$ 758
EZ	Manage Various Customer Care Processes	$ 2,075	$ 2,075
IS	Bill Customers	$ 57,019	$ 54,642
IT	Manage Credit	$ 15,239	$ 15,238
IU	Collect Revenue	$ 10,253	$ 10,252
	Total	$ 85,344	$ 82,965

** PG&E's Updated Forecast includes labor escalation adjustments, concessions PG&E made during Rebuttal Testimony and adjustments PG&E made as a result of reaching a stipulation with the parties.
Response of PG&E to ALJs' Ruling, Dated May 20, 2020, Updated Appendix B, Page 5.

MWC AR (Read and Investigate Meters) includes the costs of work performed related to the retrieval of internal electric and gas meter data for large commercial, industrial and agricultural customers via telephony-based metering and field retrieval of interval data. MWC EZ (Manage Various Customer Care Processes) includes the costs of miscellaneous work performed by the Complex Billing department, the Customer Revenue Processing department, and the

Printing and Bill Presentment department. MWC IS (Bill Customers) includes the costs of billing activities performed by the following seven departments: Billing Operations Exceptions; Business Delivery; Complex Billing; Billing System and Analytics; Printing and Bill Presentment; Revenue and Statistics; and Credit Policy and Operations. MWC IT (Manage Credit) includes the costs of work related to past-due accounts performed by the Credit Policy and Operations department, the Printing and Bill Presentment department, and the Field Meter Operations department. MWC IU (Collect Revenue) includes the costs of collection activities performed by the Customer Revenue Processing department, the Enterprise Revenue Strategy department, and the Revenue and Statistics department.

The BRC team also requests a capital expenditure forecast (MWC 2F-Build IT Apps & Infrastructure) of $7.467 million in 2018 and $252,000 in 2019 for IT projects that support BRC activities. These IT projects include projects to help increase customer adoption of paperless billing and projects to digitize and streamline customer experience.[173]

9.6.1. Customer Fees

PG&E charges customers fees if their checks are returned for non-sufficient funds (NSF fee) or if they need to reconnect to utility services. These fees are governed by Rules 9.H and 11.M.

PG&E proposes to lower its service reconnection fees. Currently, PG&E charges a reconnection fee of $17.50 for non-CARE customers and $11.25 for CARE customers.[174] Based on PG&E's forecasts of volume and cost for remote

[173] Exhibit 91 at 7-11 to 7-15 and 7-20.

[174] Exhibit 91 at 7-22.

and field connections, PG&E proposes to reduce its service reconnection fee to $15.75 (a 10 percent decrease) for non-CARE customers and $10.25 (a 9 percent decrease) for CARE customers.[175]

PG&E also proposes to reduce its NSF fee. Currently, PG&E's NSF fee is $7.00. The fee, which was initially adopted in the 2011 GRC, is derived based on an analysis of total labor costs, notice generation costs, working capital costs, and fees charged to PG&E by the banks that process the customer payments. For 2020, PG&E forecasts a reduction in these costs and is proposing to reduce the NSF fee to $4.60 (a 34 percent decrease).

9.6.2. Uncollectible

PG&E proposes using the same methodology it has previously used to forecast its annual uncollectible factor, which is to use a rolling 10-year average. For 2020, the uncollectible factor is 0.003263.

9.6.3. Disconnections for Nonpayment

Pub. Util. Code Section 718(b) directs the Commission to consider the impact of any proposed increase in rates on disconnections for nonpayment and to incorporate a metric for residential nonpayment disconnections in each energy utility's general rate case proceeding.

PG&E conducted an analysis of its residential bill and disconnection data for the 2010-2017 period. Its analysis shows that the correlation between residential bills and the volume of nonpayment disconnections is none-to-weak for non-CARE customers but is moderate-to-high for CARE customers.[176]

The Settlement Agreement reflects compromises that settling parties made in the interest of customer affordability. The settling parties agreed on a $19.5

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175 *Ibid.*

176 Exhibit 93 at 7-5 to 7-6 (Table 7-2 and Table 7-3).

million reduction to PG&E's originally forecasted expenses in the areas of Energy Supply, Customer Care, Shared Serves and Information Technology, and Human Resources for the purpose of customer affordability. Overall, the settlement's revenue requirement, according to the settling parties, results in a 3.4 percent increase to gas and electric bills in 2020.[177] The settling parties believe that this impact "achieves a fair balance between safety, reliability, and affordability."[178]

We acknowledge the settling parties' efforts to lower forecasted expenses to reduce bill impacts and make rates more affordable for customers. We have heard from the public at the PPHs and through letters expressing concerns that PG&E's rates are too high and unaffordable, and determined it appropriate to consider the impacts that any revenue requirement increase from this application would have on customer affordability. The 3.4 percent increase to utility rates that would result from the settlement's revenue requirement represents a balance of customer affordability, reliability, and safety, particularly in light of the significant wildfire mitigation investments PG&E will need to make due to the heighted wildfire risks in our current environment.

We also consider the impacts any revenue requirement increase from this application would have on disconnections. Pursuant to Resolution M-4842, the Commission currently has a moratorium on utility disconnections because of the novel coronavirus, COVID-19, pandemic. Because of this moratorium, the revenue requirement approved in this proceeding will not have any immediate impacts on customer disconnections for non-payment.

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[177] Joint Motion for the Settlement Agreement at 15.

[178] *Ibid.*

Notwithstanding the moratorium, the Commission is considering issues related to customer disconnections resulting from non-payment across the regulated utilities in R.18-07-005 (Disconnections Rulemaking). D.20-06-003, which the Commission issued in Phase I of the Disconnections Rulemaking, put an annual cap on the percentage of residential customer accounts that PG&E can disconnect from utility service at four percent for 2020, 2021, and 2022.[179] We will use the four percent cap as the metric for residential nonpayment disconnections, as directed in Pub. Util. Code Section 718(b).

In order for the Commission to assess the impact any future proposed rate increase has on customer affordability and disconnections, PG&E shall report in its next GRC filing a) the actual annual percentages of residential utility disconnections for nonpayment during this GRC cycle, and b) analysis of the impacts rate increases have on disconnections during this GRC period. We understand that any meaningful analysis of disconnections can only be done on data collected after the current moratorium cycle.

9.6.4. Settlement Agreement

Under the Settlement Agreement, the settling parties agree to reduce PG&E's expense forecast by $1.2 million for MWC IU, which are the costs of collection and payment processing activities, in the interest of customer affordability. Other than MWC IU, the settling parties adopt PG&E's forecasts and proposals for the BRC functions.

9.6.5. Positions of the Parties

The parties did not dispute PG&E's forecasts for the BRC department and PG&E's proposed reductions to its service reconnection fee and NSF fee. The

[179] D.20-06-003, Ordering Paragraph 1.

parties also did not dispute PG&E's proposed methodology and calculation of the uncollectible factor.

9.6.6. Discussion

The settling parties agree to a reduction of $1.2 million to PG&E's forecast for MWC IU (costs of collection and payment processing activities) in the interest of customer affordability.[180] The comments from the public that the Commission received at the public participation hearings (PPHs) and through letters express concerns over PG&E's high utility rates and request the Commission lower PG&E's rates so that they are more affordable. Thus, we consider it reasonable for the settling parties to agree to reduce PG&E's forecast of MWC IU by $1.2 million in the interest of customer affordability. We adopt the settlement's forecast for MWC IU.

In addition, we reviewed PG&E's forecasts for the other BRC expenses, as well as PG&E's proposed fee reductions for its service reconnection service and NSF check returns. PG&E's forecasts, including the forecast of the uncollectible factor, and PG&E's proposed fee reductions, as adopted by the settlement, are reasonable, and we adopt them.

9.7. Regulatory Policy and Compliance

In this section, PG&E requests recovery of expenses for its Customer Care Regulatory Policy and Compliance (CCRPC) department, as well as the Operational Management (OM) and Operation Support (OS) expenses supporting the Customer Care organization. The CCRC department performs the following functions: risk, compliance and audit; customer and employee

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[180] Joint Motion of the Setting Parties for Approval of Settlement Agreement at 31.

privacy; tariff interpretation; certain regulatory proceedings; and contract management.

PG&E requests $15.1 million in TY2020 expenses for the CCRPC department, which consist of $7.860 million (MWC EZ - Manage Variable Cust Care Processes) for the CCRPC department (an increase of $0.972 from 2017 recorded expense) and $7.241 million for Customer Care's MWCs OM (Operational Management) and OS (Operational Support) support costs (a decrease of $2.638 million compared to 2017 recorded expenses). The following table shows a breakdown of the requested expenses:

Expenses *(in Thousands of Dollars)*		
MWC	**Activities**	**PG&E's Forecast**
EZ	Manage Var Cust Care Processes	$ 7,860
OM	Operational Management	$ 6,933
OS	Operational Support	$ 308
	Total	$ 15,101

9.7.1. Settlement Agreement

Under the Settlement Agreement, the settling parties agree to reduce PG&E's expense forecast by $2.8 million for MWC OM, which are the labor and employee costs of providing supervision and management support for the Customer Care organization, in the interest of customer affordability. Other than MWC OM, the settling parties adopt PG&E's forecasts for MWC EZ and MWC OS.

9.7.2. Positions of the Parties

The parties did not dispute PG&E's forecasts presented in this section for MWCs EZ, OM, and OS.

9.7.3. Discussion

The settling parties agree to a reduction of $2.8 million to PG&E's forecast for MWC OM (supervisory and management costs for the Customer Care organization) in the interest of customer affordability.[181] The comments from the public that the Commission received at the PPHs and through letters express concerns over PG&E's high utility rates and request the Commission to lower PG&E's rates so that they are more affordable. Thus, we consider it reasonable for the settling parties to reduce PG&E's forecast of MWC OM by $2.8 million in the interest of customer affordability. We adopt the settlement's forecast for MWC OM.

In addition, we reviewed PG&E's forecasts for MWC EZ and MWC OS. PG&E's forecasts, as adopted by the settlement, are reasonable, and we adopt them.

10. Shared Services and Information Technology

This section addresses the O&M, capital, and other requests relating to Shared Services and IT. In Article 2.6.1 of the Settlement Agreement, the settling parties agree to adopt $544.7 million for TY2020 O&M expenses. For capital projects, the settling parties agree to adopt $575.561 million for 2018, $426.327 million for 2019, and $434.997 million for 2020 with the 2018 capital expenditures being subject to the adjustment described in Article 3.2 of the settlement. This adjustment is discussed with greater detail in the Other Adjustments section of the decision.

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[181] Joint Motion of the Setting Parties for Approval of Settlement Agreement at 31.

10.1. Shared Services

Shared Services generally provide company-wide support to PG&E's lines of business (LOB) and are comprised of the following organizations and departments: (a) Safety and Health; (b) Transportation and Aviation Services; (c) Materials; (d) Sourcing; (e) Real Estate; (f) Land and Environment Management; and (g) Enterprise Records and Information Management.

10.1.1. O&M Costs

The O&M forecasts for TY2020 adopted by the settlement for each of the seven departments under Shared Services are discussed below. Tables reflecting PG&E's forecasts and the amounts adopted in the Settlement Agreement are included in the discussion of each department. The tables will show PG&E's original forecasts, the amounts adopted in the settlement, and the difference between the two. The settlement amounts include the labor escalation adjustments adopted in the settlement. Reasonableness of these adjustments is discussed in greater detail in the Human Resources section of the decision. For Shared Services, the general impact of the adopted labor escalation adjustments is to reduce PG&E's forecasts by one to several thousand dollars for costs where there is a labor component.

10.1.1.1. Safety and Health

The Safety and Health department is responsible for identifying, evaluating, and controlling hazards, risks, and exposures to protect PG&E's employees and contractors.[182]

As shown in the table below, the settlement adopts PG&E's forecast for Safety and Health of $33.248 million. Parties do not object to PG&E's forecast. According to Cal Advocates, PG&E's forecast reflects historical costs from 2013

[182] Exhibit 66 at 1-1.

to 2017 and the increase from 2017 expenditures of $29.60 million, reflects escalation of costs.[183] The slight differences between PG&E's forecasts and the amounts adopted in the settlement are due to the labor escalation adjustments that are incorporated in the settlement amounts.

Safety and Health	PG&E Forecast	Settlement Reduction	Settlement Amount
Miscellaneous Expense	$9,828,000	$1,000	$9,827,000
Safety Engineering & OSHA Compliance	$17,428,000	$1,000	$17,427,000
Maintain IT Apps & Infrastructure	$188,000	$0	$188,000
Provide Human Resources Services	$5,807,000	$1,000	$5,806,000
Total	**$33,251,000**	**$3,000**	**$33,248,000**

Miscellaneous Expenses

Miscellaneous Expenses include labor associated with Department of Transportation (DOT) compliance, Enterprise Corrective Action Program (ECAP)[184] costs, and labor costs for business operations focus areas.

Safety Engineering & OSHA Compliance

Safety Engineering & OSHA Compliance includes labor associated with injury management, health and wellness, serious injury and fatality prevention, contractor safety, and other related areas. It also includes all contract costs incurred by the Safety and Health department and costs for staff augmentation.

Maintain IT Apps & Infrastructure

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[183] Exhibit 192 at 4.

[184] The ECAP provides a centralized structure and process for issue resolution and tracks equipment and safety issues, ineffective and inefficient work processes and procedures, and provides suggestions how to improve such processes and procedures.

This cost category relates to O&M costs associated with the Enterprise Corrective Action Program (ECAP) capital project. Discussion of the ECAP is found in the capital portion of this section.

Provide Human Resources Service

Costs under this category include labor costs associated with the Integrated Disability Management (IDM) department. The IDM department manages PG&E's disability and workers' compensation programs.

10.1.1.2. Transportation and Aviation Services (TAS)

According to PG&E, TAS helps support over 13,000 vehicles and related equipment utilized to service PG&E's 70,000 square mile service territory.[185] Assets under TAS include all vehicles, construction equipment, trailers, and aircraft. TAS provides helicopter service, patrol aircraft, and other aviation-related services to support the operations and assets. TAS also maintains one aircraft to principally serve DCPP operations. The settlement adopts PG&E's forecasts for TAS with the resulting differences being attributable to the labor escalation adjustments incorporated in the settlement amounts.

Transportation and Aviation Services	PG&E Forecast	Settlement Reduction	Settlement Amount
Transportation Services Expenses and Credit	$86,195,000	$25,0000	$86,170,000
Aviation Services Expenses	$5,362,000	$3,0000	$5,359,000
Maintain Apps & Infrastructure	$16,000	$0	$16,000
Total	**$91,573,000**	**$28,000**	**$91,545,000**

Transportation Services Expenses (and Credit)

Transportation Services Expenses include all O&M costs necessary to support PG&E's LOBs. Costs are forecast at the company level and the resulting

[185] Exhibit 66 at 2-1.

company-wide forecast is referred to as the Gross forecast. The amount requested in the GRC however, which is referred to as the Net Forecast, removes expenses recovered in other proceedings, and any capital or balancing account-funded amounts (overhead credit).[186] Costs included in the Net Forecast include expenses for operating and maintaining PG&E's vehicle fleet, depreciation costs, fuel costs, and rental costs.

Aviation Services Expenses

Aviation Services Expenses support costs for aircraft and helicopter operations and include ongoing expenses such as escalated fuel, maintenance, navigation software subscription fees, and hangar lease costs. PG&E's forecast for TY2020 is approximately $1.60 million higher than recorded expenditures of $3.8 million in 2017. The increase is primarily due to additional O&M costs resulting from the proposed acquisition of four heavy lift helicopters requested in this proceeding. The request for these four heavy lift helicopters is discussed in the capital section of this chapter.

Maintain IT Apps and Infrastructure

There are no new IT initiatives under TAS and the forecast amount of $16,000 is for software access, maintenance, and upgrades. TAS maintains information databases on all owned, leased, and rented mobile assets including information regarding maintenance schedules.

10.1.1.3. Materials

The Materials unit manages a materials distribution network throughout PG&E's service territory in support of PG&E's maintenance and construction

[186] *Id* at 2-25.

activities. According to PG&E, management and delivery of materials and supplies is a critical component of its operations.

Materials	PG&E Forecast	Settlement Reduction	Settlement Amount
Materials Expenses	$1,604,000	$0	$1,604,000
Total	**$1,604,000**	**$0**	**$1,604,000**

Materials Expenses

The forecast for Materials is $1.604 million which addresses expenses relating to internal company mail which includes labor costs for pickup, and transportation and delivery of internal company mail. Costs for TY2020 are around the same level as expenditures in 2017 of $1.66 million.

10.1.1.4. Sourcing

Sourcing is responsible for the procurement of goods and services required by PG&E's LOBs. These include, but are not limited to, construction and maintenance services, distribution equipment, IT software and equipment, chemicals and oil products, construction equipment, vehicles and automotive parts, tools, office supplies, furniture, and services for engineering, environmental, professional, and technical services.[187] The settlement adopts PG&E's forecasts except for slight differences in the settlement amount due to labor escalation adjustments adopted by the settlement.

Sourcing	PG&E Forecast	Settlement Reduction	Settlement Amount
Operational Support	$6,697,000	$8,000	$6,689,000
Sourcing Operations Support	$16,574,000	$1,000	$16,573,000
Maintain Apps & Infrastructure	$36,000	$0	$36,000
Total	**$23,307,000**	**$9,000**	**$23,298,000**

[187] Exhibit 66 at 4-1.

Operational Support

Operational support includes costs for service organizations supporting major business drivers.

Sourcing Operations Support

Costs under this category include procurement specific costs to support PG&E's business operations.

Maintain Apps & Infrastructure

Costs included in this category are those for ongoing maintenance, operations, and repair for PG&E's applications, systems, and infrastructure.

10.1.1.5. Real Estate

Corporate Real Estate Strategy and Services (CRESS) is PG&E's Real Estate organization and is responsible for governing, planning, acquiring, designing, constructing, operating and maintaining 7.7 million square feet of facilities throughout PG&E's service territory.[188] These facilities include, but are not limited to, service centers, data centers, contact centers, office buildings, shops, warehouses, construction and equipment yards, vehicle maintenance garages, customer service offices, and meeting and training facilities. The table below shows PG&E's forecasts and the amounts adopted in the settlement.

Real Estate	PG&E Forecast	Settlement Reduction	Settlement Amount
Building Service Credit	-($65,891,000)	-($1,000)	-($65,890,000)
Facilities Asset Upkeep	$4,004,000	$0	$4,004,000
Facilities Management	$111,813,000	$4,816,000	$106,997,000
Real Estate Management	$8,183,000	$0	$8,183,000
Maintain Apps and Infrastructure	$1,420,000	$0	$1,420,000
Total	**$59,529,000**	**$4,815,000**	**$54,714,000**

[188] Exhibit 66 at 5-1.

Building Service Overhead Credit

Building Service Overhead Credit represents the GRC portion of CRESS costs recovered from other proceedings excluding amounts attributed to capital projects and any balancing account-funded amounts (overhead credit).

Facilities Asset Upkeep (FAU)

The FAU program provides proactive maintenance practices that optimize life cycle costs and limit unplanned business interruptions. This process includes replacements that minimize costly maintenance and unplanned business interruptions and provides PG&E with better overall customer service. Costs for FAU also include costs for inspection and maintenance of PG&E's facilities.

Facilities Management

Facilities Management operates and maintains PG&E's facilities and includes the following departments: (a) Facilities Management Operations which handles call intake of facilities issues and general building office requests; (b) Critical Operations which manages critical facilities that house crucial core computer or customer support operations essential to providing reliable and responsive service to electric and gas customers; (c) Facilities Capital Planning which supports PG&E's risk-based condition assessment program; and (d) Facilities Program Groups which manages PG&E's conference centers.

Real Estate Management

Real Estate Management costs are for costs relating to lease management and land acquisition support for the CRESS organization. This includes facilities such as office buildings, service centers, customer centers, special purpose sites, and warehouses.

Maintain Apps and Infrastructure

Costs under this category are O&M costs for janitorial, landscaping, building maintenance, and repair work in support of capital projects.

10.1.1.6. Land and Environment Management

The Land and Environmental Management (LEM) organization is responsible for environmental remediation, permitting and compliance, establishing policies and programs aimed at reducing PG&E's operational footprint, and managing environmental sustainability.[189] The settlement adopts PG&E's TY2020 forecasts as shown in the table below. Once again, the slight difference between PG&E's forecasts and the settlement amounts are due to the incorporation of the labor escalation adjustments adopted in the Settlement Agreement.[190]

Land and Environment Management	PG&E Forecast	Settlement Reduction	Settlement Amount
Environmental Remediation	$1,974,000	$0	$1,974,000
Land Management	$3,462,000	$2,000	$3,460,000
Environmental Management	$12,798,000	$4,000	$12,794,000
Maintain IT Apps and Infrastructure	$16,000	$0	$16,000
Provide Regulation Services	$1,465,000	$0	$1,465,000
Operational Management	$201,000	$0	$201,000
Operational Support	$427,000	$0	$427,000
Total	**$20,343,000**	**$6,000**	**$20,337,000**

Environmental Remediation

Environmental Remediation manages the clean-up of legacy contaminated sites for which PG&E retains environmental liability. These sites include both active and former operating facilities such as gas plants and fossil fuel power

189 Exhibit 192 at 18.

190 Settlement Agreement Section 2.7.3.

plants. PG&E has completed many remediation projects although some projects are still in progress.

Land Management

Land Management is responsible for management of PG&E's lands and land rights. This includes maintaining and protecting PG&E's property and easements, as well as implementing sustainable forest management practices that improve forest health and mitigate the spread of wildfires. Expenses under this category are influenced by the implementation of programs such as the Land Conservation Commitment Program and Land Stewardship Management Plans.

Environmental Management

Environmental Management is responsible for managing environmental compliance and obtaining environmental permits for distribution, transmission, and generation projects. The department is also responsible for routine O&M activities and ensuring environmental compliance during new construction.

Maintain IT Apps and Infrastructure

Costs under this category are for O&M expenses associated with enhancements to safety and ECAP technology.

Operational Management

Operational Management costs are for expenses incurred by PG&E's Environmental Policy unit which provides oversight and management relating to hazardous waste program activities.

Operational Support

Operational Support includes expenses for providing support to PG&E's service organizations.

10.1.1.7. Enterprise Records and Information Management

PG&E's Enterprise Records and Information Management (ERIM) program is responsible for designing and implementing strategies and processes for PG&E's records and information management and ensures that its records are traceable, verifiable, accurate, and complete. The table below shows costs for ERIM forecast for ERIM. Once again, the settlement adopts PG&E's forecast except for a $1,000 difference resulting from labor escalation adjustments also adopted by the Settlement Agreement.

Enterprise Records and Information Management	PG&E Forecast	Settlement Reduction	Settlement Amount
ERIM Program Costs	$15,576,000	$1,000	$15,575,000
ERIM IT Costs	$2,650,000	$0	$2,650,000
Total	**$18,226,000**	**$1,000**	**$18,225,000**

ERIM Costs

ERIM costs are for projects that support implementation, costs relating to operational baseline activities involving third-party vendor spending, and costs incurred by the gas RIM team.

ERIM IT Costs

ERIM IT Costs are for projects designed to drive consistency in how PG&E implements governance for electronic records as well as how it stores and manages content.

10.1.1.8. Positions of the Parties

The Settlement Agreement adopts all of PG&E's proposed O&M costs for Shared Services except for a reduction of approximately $4.9 million to its forecast for Real Estate Facilities Management.

Cal Advocates originally recommended approximately $22.5 million in reductions to PG&E's forecasts for TAS and Real Estate Expenses. Regarding TAS costs, Cal Advocates utilized a different estimate for storm and wildfire expenses allocated to capital and balancing accounts. For Real Estate Expenses, Cal Advocates argued that historical expenses show a downward trend in expenditures.

TURN originally recommended a reduction of approximately $1.3 million for Aviation Services expenses. TURN objected to the purchase of four heavy lift helicopters and the $1.3 million reduction corresponds to the O&M costs to maintain the four helicopters. The proposal to acquire these four helicopters is discussed in the capital portion of this chapter.

JCCA proposes reducing Aviation Services expenses which corresponds to its recommendation of granting authority to purchase only one of the four helicopters.

NDC originally argued that PG&E did not spend the required amount for the Technical Assistance Program (TAP) which is a program under the Sourcing department.

The remaining adjustments to PG&E's forecasts are due to the inclusion of labor escalation adjustments ranging from $1,000 to $25,000, to the settlement amounts. Reasonableness of the labor escalation adjustments adopted in the settlement is discussed in the Human Resources section of the decision.

10.1.1.9. Discussion

Parties do not object to the amounts adopted by the settlement for Safety and Health, Materials, Sourcing, Land and Environment Management, and ERIM. We reviewed the proposed costs for these departments and find them reasonable. Most of the costs proposed for the above departments are not for new activities but represent activities that are already being performed. PG&E simply plans on continuing these activities and the increases in costs from 2017 recorded expenses are adequately explained in testimony.

The adopted forecast for Safety and Health of $33.248 is almost $4 million higher than PG&E's 2017 recorded expenses reflecting increases in staffing needed to fill roles with respect to DOT Compliance, ECAP, and business operations.

The forecast for Materials is approximately $1.4 million higher than 2017 recorded expenses because some costs were allocated to LOBs in 2017.[191] In addition, increased costs are also anticipated for operating PG&E's internal mail services.

Costs for Sourcing are $2.4 million lower than 2017 recorded expenses largely due to operational efficiencies. Prior to the settlement, NDC argued that PG&E underspent amounts for TAP but we find this issue to be resolved as part of the agreement between PG&E and NDC[192] wherein PG&E makes a commitment to spend a total of $2.4 million for TAP in this GRC cycle.[193]

Land and Environment Management costs are $3 million lower than 2017 expenses in part due to customer affordability initiatives aimed at reducing expenses. Similarly, the forecast for ERIM is approximately $2.3 million lower than 2017 expenditures because of reductions to ERIM project costs as the program matures.

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[191] PG&E explains that some costs will still be allocated to LOBs

[192] Settlement Agreement Appendix G.

[193] PG&E and NDC Agreement Stipulation 2.

TAS Expenses

With respect to cost forecast for TAS, the settlement adopts PG&E's forecast of $91.5 million which is approximately $21.8 million higher than 2017 expenses of $69.85 million. Parties do not object to the forecast for Maintain Apps and Infrastructure but objections were made to the forecasts for Transportation Services Expenses (including the Overhead Credit) and Aviation Services.

PG&E explains that the projected increase for Transportation Services Expenses represents a nine percent increase over a three-year period. PG&E states that this is largely due to a change in the cost model for TAS O&M and capital costs. According to PG&E, higher allocations for capital and balancing account expenditures in 2017 for storm and wildfire support resulted in less costs being allocated for O&M. To illustrate, O&M expenditures in 2017 were more than $9 million less than O&M expenditures in 2016.

On the other hand, Cal Advocates argues that storm and wildfire events are unpredictable and can also occur during the TY. However, we find PG&E's explanation more credible. Although storm and wildfire costs are still included in the TY2020 forecast, the forecast amount does not anticipate the unusually high levels of incidents that occurred during 2017.[194] In addition, PG&E will no longer apply Fleet Overhead Credits to GRC balancing accounts and is changing the way it calculates Overhead Credit for catastrophic events beginning in TY2020. This change aims to remove the impact of storm and wildfire unpredictability.[195]

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[194] Exhibit 73 at 2-9.

[195] *Ibid*.

PG&E also explains that increased costs are anticipated for helicopter and aircraft maintenance as well as additional costs for the four new firefighting helicopters as discussed in the capital section.

Based on the foregoing, we find that there is enough basis to conclude that the amount of Overhead Credit for this GRC cycle is not expected to be as high as Cal Advocates proposes (more than $22 million higher than what PG&E had forecast). We also find PG&E's model more reasonable because it is not predicated solely on the expenses incurred in 2017, which were largely impacted by storm and wildfire support costs.

With respect to the issues raised by TURN and JCCA concerning O&M costs for the four firefighting helicopters proposed by PG&E, these issues are addressed in the capital section of this chapter.

Real Estate Expenses

Regarding costs for Real Estate, the Settlement Agreement adopts a forecast of $54,614 million which is approximately $4.9 million less than PG&E's forecast of $59.529 million.

Cal Advocates originally recommended a reduction of $11.5 million to PG&E's forecast using 2018 recorded expenses as a basis. Cal Advocates argued that there is a clear downward trend in recorded CRESS expenses. PG&E explains that the downward trend is not as steep as Cal Advocates is forecasting and that there are other factors for increased costs which Cal Advocates did not consider.

Based on our review of historical expenses from 2013 to 2017, we agree that costs have generally been decreasing although not at the level experienced from 2017 to 2018. PG&E explains that costs in 2018 represent an extreme case and cites various factors. However, while we agree that use of historical data is meant to account for an anomalous year, we find that PG&E was not able to completely refute that the downward trend in CRESS expenditures will continue. Thus, we find the settlement reduction of approximately $4.9 million represents a fare compromise between PG&E's forecast and Cal Advocates' recommended reduction of $11.5 million. We find that both parties presented reasonable arguments in support of their positions but that neither was able to establish clearly and convincingly that their position is more correct than the other party's.

10.1.1.10. Summary

Based on the discussions above regarding Shared Services O&M expenses, we find the settlement forecast for the seven Shared Services organizations totaling approximately $242.741 million reasonable and should be adopted.

10.1.2. Companywide Expenses

The settling parties also agree to adopt PG&E's forecasts for Shared Services Companywide Expenses in the amount of $80.614 million. Activities included under this category are those that benefit the company as a whole. Most of the costs relate to PG&E's Long-Term Disability (LTD) and Workers Compensation (WC) programs. The table below shows PG&E's forecasts which are all adopted by the Settlement Agreement.

Shared Services Companywide Expenses	PG&E Forecast	Settlement Reduction	Settlement Amount
Long-Term Disability (Including short-term disability insurance and adjustment)	$18,743,000	$0	$18,743,000
Workers Compensation	$49,800,000	$0	$49,800,000
DOT Drug Testing	$635,000	$0	$635,000
Employee Assistance Program	$2,158,000	$0	$2,158,000
Wellness Program	$9,278,000	$0	$9,278,000
Total	**$80,614,000**	**$0**	**$80,614,000**

Long-Term Disability (LTD)

LTD provides PG&E employees with partial income replacement and continued medical and life insurance coverage for employees who are unable to work due to their disability.

Workers Compensation

PG&E's WC program costs include WC benefits payments and related fees, alternative security program, cost containment programs, transitional light-duty payroll, on-or near-site clinics, and early symptom intervention.

DOT Drug Testing

The forecast for DOT Drug Testing is for costs to meet regulatory requirements for timely drug testing required by the Federal Motor Carrier Safety Administration, Pipeline and Hazardous Materials Safety Administration, and Federal Aviation Administration.

Employee Assistance Program (EAP)

EAP is a component of PG&E's Health and Wellness Program which offers support to many employees regarding various personal and professional issues that can negatively affect work.

Wellness Program

PG&E's Wellness Program is designed to help employees and their dependents increase their awareness, take action, and improve health. The forecast also includes costs for expanded availability and utilization of the clinical support program, expected increased utilization of EAP programs, and escalation provisions included in vendor contracts.

10.1.2.1. Discussion

As shown in the table above, the settlement adopts PG&E's TY2020 forecast for Shared Services Companywide Expenses. Parties do not oppose to PG&E's forecasts. Costs for these programs fall under activities managed by

PG&E's IDM which is responsible for WC payouts, on-site medical short-term disability supplements, LTD contributions, medical evaluations related to fitness for duty, and other costs related to these programs.

The above programs are either mandated by law or are standard programs and benefits offered to employees by companies such as PG&E and the Commission has authorized costs to support these programs in prior GRCs. We reviewed the proposed costs and find the forecasts consistent with historical expenditures. In 2017, recorded expenditures for IDM were approximately $85.268 million[196] compared to $80.614 million that is being adopted by the Settlement Agreement.

Based on the discussions above, we find the settlement amount of $80.614 million adopted by the settling parties for Shared Services Companywide Expenses reasonable and should be adopted.

10.1.3. Capital

The settlement adopts PG&E's Shared Services capital forecasts for 2018, 2019, and 2020. The table below shows the total amounts adopted in the Settlement Agreement for 2018, 2019, and 2020 for each of the seven departments that comprise Shared Services.[197] As is the case with capital projects in other sections, the amounts for 2018 are subject to the adjustment described in Article 3.2 of the Settlement Agreement wherein the forecast amounts for 2018 are to be updated with recorded 2018 capital expenditures.

Shared Services Capital	2018	2019	2020
Safety and Health	$60,000	$62,000	$72,000

[196] Exhibit 188 at 6.

[197] The project groupings are shown in Appendix B of the Settlement Agreement at 10 to 14.

Transportation and Aviation	$65,700,000	$52,332,000	$32,180,000
Materials	$800,000	$800,000	$800,000
Sourcing	$0	$0	$0
Real Estate	$308,838,000	$165,817,000	$170,188,000
Land and Environment Management	$11,779,000	$6,279,000	$6,279,000
Enterprise Records and Information Management	$1,590,000	$1,679,000	$2,425,000
Total	**$388,767,000**	**$226,968,000**	**$211,944,000**

10.1.3.1. Safety and Health Capital

Build IT Apps and Infrastructure

Capital projects for Safety and Health include safety-related and ECAP technology enhancements relating to hardware upgrades necessary to support routing software maintenance.

10.1.3.2. Transportation and Aviation Capital

Fleet/Auto Equipment

Capital projects under Fleet/Auto Equipment include a five-year fleet replacement plan designed to replace vehicles and equipment currently coming to the end of their economic life. The replacement plan ensures that all fleet assets meet or exceed state and federal regulations. PG&E's forecast is approximately $60 million less than 2017 recorded costs because there are no forecasted additions to PG&E's fleet and because PG&E is extending asset class lifecycles for this rate case cycle by two years as compared to historical lifecycles.[198]

[198] Exhibit 66 at 2-1.

Tools and Equipment

Capital projects under this category include replacement of capital tools and equipment necessary to prevent delays to fleet repairs, which could otherwise result in increased maintenance expenses and vehicle downtime.

Miscellaneous Capital

Miscellaneous Capital consists primarily of the purchase of four firefighting helicopters as part of PG&E's CWSP. The project is forecast at $15.0 million for 2018 and $16.0 million for 2019 and includes costs to repower all four helicopters with new engines.

EV Station Infrastructure

Capital expenditures included under EV Station Infrastructure are for projects associated with continuing PG&E's multi-year plan to establish safe, standardized EV charging infrastructure at PG&E facilities for its fleet and employees. According to PG&E, this project will provide the necessary infrastructure improvements to support the growing demand for EV charging infrastructure from its electric-powered fleet and employees.

10.1.3.3. Materials Capital

Tools and Equipment

Materials Capital costs are for tools and equipment for PG&E's materials management operation. The material management operation supports maintenance and construction activities.

Miscellaneous Capital

Miscellaneous Capital costs are for capital labor projects relating to investment recovery such as equipment salvage.

10.1.3.4. Sourcing Capital

There are no capital projects for the Sourcing department.

10.1.3.5. Real Estate Capital

Maintain Building

Capital projects under this category relate to PG&E's FAU Program and includes projects for: (a) replacement or upgrade of electrical, lighting, mechanical, and plumbing systems; (b) replacement or renovation of building infrastructure systems and subsystems such as asphalt, roofing, fire detection/prevention, fencing, and painting; and (c) replacement or remediation of interior building components, such as doors, ceilings, and floor coverings.

Implement Real Estate Strategy

Capital projects under this category relate to upgrades and improvements for general office, Service Center Investment, PG&E's Customer Service Office Investment Plan, and LOB operational initiatives.

10.1.3.6. Land and Environmental Management Capital

Build IT Applications and Infrastructure

Projects under this category are for upgrades relating to development and enhancement of applications and infrastructure.

Tools and Equipment

Tools and Equipment capital costs are for replacement of aging tools with new technologies.

Implement Environmental Projects

Implement Environmental Projects are for projects relating to spill control, berm installation[199] and containment, drainage mitigation, pond wall and coating installation, underground storage tanks, treated wood pole disposal, installation

[199] A berm is a level space, shelf, or raised barrier (usually made of compacted soil) separating two areas.

of hazardous waste accumulation sheds, and installation of treatment units for drinking water systems.

10.1.3.7. ERIM Capital

Build Applications and Infrastructure

Projects under this category are for ERIM storage, management, protection of electronic records, and protection of other information assets.

Miscellaneous Capital

Capital projects under this category are for projects to implement a storage solution that will safely manage nitrate negatives. This is to help ensure long-term access to PG&E's records and historical assets.

10.1.3.8. Positions of the Parties

Cal Advocates originally recommended using a four-year average from 2013 to 2016 to determine the forecast for Real Estate capital projects for 2019 and 2020. Specifically, Cal Advocates recommended adopting $90.4 million for 2019 and 2020 compared to PGE&E's forecasts of $165.8 million for 2019 and $170.2 million for 2020.

TURN and Cal Advocates also opposed the purchase of four firefighting helicopters which will form part of PG&E's CWSP. JCCA opposes the purchase four helicopters and instead recommends the purchase of only one firefighting helicopter.

10.1.3.9. Discussion

As stated above, the settlement adopts all of PG&E's capital forecasts under Shared Services. Cal Advocates' recommendation of adopting 2018 recorded expenses for capital projects is addressed by Article 3.2 of the Settlement Agreement which requires PG&E to adjust its RO model by replacing

2018 capital forecasts with 2018 recorded capital costs. Article 3.2 is discussed in more detail in the Other Adjustments section of the decision.

There were no objections to PG&E's proposed capital projects under Safety and Health, Materials, Land and Environment Management, and ERIM. We reviewed the proposed capital projects for these organizations and find them to be necessary. We also find the adopted costs in the settlement reasonable. Projects under these organizations pertain to hardware and software upgrades that aim to increase functionality and replace outdated software, projects for application enhancements, capital tools and equipment to replace aging or obsolete tools and equipment, improvements to infrastructure, and storage solutions. These types of capital projects are routinely requested in GRCs and have generally been approved by the Commission when it determines that the projects necessary and the costs reasonable. And we find this to be the case here.

TAS

Regarding capital projects under TAS, parties oppose the purchase of four firefighting helicopters which PG&E plans to add as part of its CWSP. Cost for the four helicopters is forecast at $15 million in 2018 and $16 million in 2019. The forecast includes costs to repower all the helicopters with new engines as well as necessary costs to retrofit them into firefighting and construction helicopters.

From the testimony submitted and from cross-examination during evidentiary hearings, we find that parties do not take issue with the necessity and planned use of the above helicopters for firefighting and construction. PG&E's testimony and workpapers provide sufficient regarding the purpose and necessity of the helicopters. However, intervenors that oppose this project argued that PG&E already has an exclusive use contract with CAL FIRE for two helicopters that have similar capabilities. These intervenors add that additional helicopters may be available for lease from other entities.

We considered the arguments raised by the above parties and find PG&E's proposal to acquire the four helicopters, necessary and reasonable. The settling parties also agree to adopt PG&E's proposal. Based on our review, we find that PG&E presented detailed testimony comparing the relative merits between ownership and renting. PG&E's testimony and workpapers also detail the benefits and costs of ownership as opposed to renting. We also find that acquisition of the helicopters enables PG&E to have exclusive availability of four helicopters for firefighting purposes instead of the two it currently shares with CAL FIRE under an exclusive lease contract. Owning its own helicopters also means not depriving CAL FIRE of any helicopters needed by CAL FIRE for emergency use. In addition, three of the four helicopters are to be available to CAL FIRE under a "call when needed" contract during fire season.[200] Thus, more helicopters will be available for emergency and firefighting purposes, not only for PG&E, but also for CAL FIRE. This situation potentially improves the state's ability to respond to and mitigate the threat of wildfires by having more resources available for such purposes.

Intervenors also argued during hearings that more such helicopters may be available for lease because of need and market conditions but no clear evidence was provided to support this argument. With respect to JCCA's proposal of purchasing only one helicopter, we agree with PG&E that the helicopters are subject to regular maintenance and so having a single helicopter means that it may not be available during an emergency situation.

[200] Exhibit 73 at 2-14.

Based on the above discussion, we find the proposed purchase of four firefighting helicopters necessary and reasonable. Authorization for this purchase also resolves the issue concerning the associated O&M costs for ongoing maintenance as discussed in the O&M portion of this chapter.

Parties do not oppose PG&E's other capital proposals under TAS and as stated previously, PG&E does not plan on adding new vehicles to its existing fleet and has also extended its asset class lifecycles for this GRC cycle by two years.

Based on the above, we find PG&E's capital forecasts for TAS adopted in the Settlement Agreement to be reasonable and supported by the evidence presented in this proceeding.

Real Estate

Regarding capital projects for Real Estate, other than its original proposal to utilize a four-year average to calculate costs, Cal Advocates also argued that PG&E's capital request is overly aggressive based on its financial condition and that the service centers it visited are still functional even though some facilities were outdated.

From our review and analysis, we find that Cal Advocates did not adequately justify why a four-year average from 2013 to 2016 should be utilized and why capital expenditures in 2017 should not be considered. Capital expenditures from 2013 to 2017 were $51.4 million, $71.3 million, $100.3 million, $138.5 million, and $201.3 million, respectively and the five-year average is approximately $112.5 million. This is more than $20 million higher than Cal Advocates' original proposal. More importantly, year-over-year expenditures from 2013 to 2017 appear to be increasing and this trend continues in 2018 where recorded capital costs increased to $248.8 million. In addition, PG&E cited specific projects that address safety and compliance such as repairing cracks, repairing deteriorating building conditions, comprehensive restoration, and other similar projects needed to remediate safety and compliance concerns.

Based on the above, we find PG&E's forecasts, which the settling parties adopt, more reasonable. We also give consideration to the agreement reached by the settling parties achieved through arms-length negotiations. However, we find that the forecast for 2018 of $308.838 million is not supported by the level of historical expenditures or by recorded costs in 2018. Instead, we find it reasonable to adopt recorded capital expenditures for 2018 of $248.8 million. However, as discussed in the Other Adjustments section of the decision, Article 3.2 requires PG&E to adjust its RO Model by replacing all 2018 capital forecasts with 2018 recorded capital expenditures and we find that this adequately addresses our above determination.

Summary

Based on the above discussions, we find it reasonable to adopt PG&E's Shared Services capital forecasts for 2018, 2019, and 2020 with the understanding that capital forecasts for 2018 will be adjusted in accordance with Article 3.2 of the Settlement Agreement

10.2. IT

This section will discuss the forecasts for IT and cyber and corporate security. PG&E's IT organization provides IT services and maintains IT assets throughout PG&E's service territory in the following portfolio of services: (a) Business Technology Projects; (b) Foundational Technology; and (c) Baseline Operations.

On the other hand, cyber and corporate (physical) security relate to controls, mitigations, and strategies to address cyber and physical security risks to PG&E's workforce, critical infrastructure, information assets, customers, and business operations.

10.2.1. O&M Costs

The table below shows the O&M costs proposed by PG&E as well as the amounts adopted by the Settlement Agreement. As shown in the table, the settlement reduces PG&E's original forecast by $7.716 million. The settlement amounts incorporate labor escalation adjustments also adopted by the settlement and these adjustments generally have the impact of reducing PG&E's forecasts by several thousand dollars.

IT and Cyber/Corporate Security	PG&E Forecast	Settlement Reduction	Settlement Amount
Maintain IT Apps and Infrastructure	$294,194,000	$7,716,000	$286,478,000
Operational Management	$521,000	$0	$521,000
Operational Support	$609,000	-($3,000)	$612,000
End User Services Overhead Credit	-($34,886,000)	-($,2000)	-($34,884,000)
Maintain IT Apps and Infrastructure (Security)	$32,512,000	$1,000	$32,511,000
Provide Risk/Security Services	$15,055,000	$0	$15,055,000
Operational Management (Security)	$1,469,000	$0	$1,469,000
Total	**$309,474,000**	**$7,712,000**	**$301,762,000**

Maintain IT Apps and Infrastructure

Costs under this category include costs for ongoing maintenance, operations, and repair of PG&E's applications, systems, and infrastructure. Most of the IT-related O&M costs fall under this category.

Operational Management

Operational Management includes labor and employee costs to provide supervision and management support for IT as well as costs for administrative staff working for said managers and supervisors.

Operational Support

Operational Support includes labor and employee-related costs to provide services and support that are unrelated to supervision and management. Examples include PG&E's Business Finance and Sourcing departments that support LOBs.

End User Services Overhead Credit

This cost category represents credits for miscellaneous support costs and overhead capital credit allocations for IT end-user services that were previously included as part of the IT device fee.[201]

Maintain IT Apps and Infrastructure (Security)

Costs under this category are for ongoing maintenance, operations, and repair of PG&E's IT applications, systems, and infrastructure related to cyber security and corporate security.

Provision for Risk/Security Services

The forecast for this cost category covers support for corporate security, risk management, internal audit, and insurance functions. Corporate security includes guard services, investigations and investigators, executive protection, access control, physical security testing, video monitoring our security facilities, and fixing broken security equipment.

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201 Exhibit 66 at 7-83.

Operational Management (Security)

Operational Management includes labor and employee-related costs for supervision and management support as well as costs of administrative staff for managers and supervisors.

10.2.2. Capital

As is the case with Shared Services capital projects, the settlement adopts PG&E's capital project forecasts for IT and Cyber/Corporate Security for 2018, 2019, and 2020. The table below shows the amounts adopted in the Settlement Agreement. Pursuant to Article 3.2 of the Settlement Agreement, the adopted amounts for 2018 are to be updated with recorded capital expenditures for 2018.

IT and Cyber/Corporate Security Capital	2018	2019	2020
Build IT App and Infrastructure	$151,016,000	$159,281,000	$184,566,000
Build IT App and Infrastructure (Security)	$19,937,000	$23,929,000	$21,846,000
Security Install/Replace	$15,842,000	$16,151,000	$16,640,000
Total	$186,795,000	$199,361,000	$223,052,000

Build Applications and Infrastructure (IT and Security)

These include capital projects to design, develop and enhance applications, systems, and infrastructure technology solutions for IT and cyber and corporate security.

Security Install/Replace

These include capital projects for new security mitigation investments to address cyber and corporate security risks. It also includes projects to design, build, install, and replace corporate security assets.

10.2.3. Discussion

Based on testimony submitted by parties, TURN was the only party that had objections to PG&E's O&M forecasts for IT and cyber security. TURN originally recommended a reduction of $2.290 million to PG&E's forecast of $294.194 million for O&M costs for Maintain IT Apps and Infrastructure.

The settlement acknowledges TURN's proposed reduction and in Article 2.6.2.3 applies a reduction of $6.5 million to promote customer affordability. We find that this reduction adequately addresses TURN's concern and agree with the settlement's efforts to promote customer affordability. We expect that the above reduction will not negatively impact safety, reliability, and the amount and level of service provided to customers. We also expect that the adopted forecast will provide PG&E with sufficient funding to conduct the necessary O&M activities under Maintain IT Apps and Infrastructure as described in its testimony.

A large part of the forecast for O&M costs are under Maintain IT Apps and Infrastructure and as discussed above, these costs are for ongoing maintenance, operations, and repair for PG&E's applications, systems, and infrastructure. The settlement amount is approximately $10.5 million higher than recorded costs in 2017 of $275.882 million. Based on our review, we find that the projected increases are in large part due to following: (a) new investments in cross-functional software applications and mobile technology necessary for PG&E's field workers; (b) new investments in software to support automation of certain processes aimed at improving efficiency, and (c) new investments to address long-term IT cost effectiveness, maintenance of asset security and reliability, to meet infrastructure demand, and to address new business technology capabilities.

For cyber security O&M costs, the increase of approximately $7.5 million from 2017 O&M expenditures adopted in the settlement can be attributed to project implementation costs to address increased risks concerning cyber and physical security as well as management and prevention of these risks.

With respect to capital costs for both IT and cyber and corporate security, the settlement adopts all of PG&E's forecasts for 2018, 2019, and 2020. Cal Advocates originally proposed reductions of approximately $13 million in 2019 and $23 million in 2020 based on reduced funding for the Integrated Grid Platform (IGP) Enablement and Network Technologies Field Area Network (FAN) project. TURN originally recommended disapproving the FAN projects entirely because of the availability of third-party networks.

The IGP IT Infrastructure Program consists of four workstreams: the FAN project; the SCADA Network Reliability Improvements; deployment of a substation Converged Platform; and the Data Center & Control Center Infrastructure Preparation.[202]

At issue here is the FAN project which involves ongoing deployment of multi-purpose wireless communication networks that provide connectivity to PG&E's network used by field devices. In reviewing the issues raised by Cal Advocates and TURN against the FAN project, we give consideration to the fact that the two parties are amongst the settling parties and that the Settlement Agreement authorizes PG&E's proposed costs for the project. More importantly, we find that Cal Advocates based its original recommendation on 2017 costs and did not consider the full scope and technology involved in the project. With respect to TURN's original objection, PG&E states that it considered using

[202] Exhibit 20 at 19-50.

third-party communication networks as an alternative but considers it important to have control of network assets that support critical operations. PG&E adds that third-party networks are not always able to meet utility-specific requirements.

There were no objections to the other IT capital projects which we reviewed and find reasonable. These IT projects are generally aimed at sustaining or improving technology, reliability and security. Other projects increase IT efficiency, enable new enterprise capabilities, and provide digital innovation. There were also no objections to capital projects for cyber and corporate security which we have also reviewed and likewise find reasonable.

Cal Advocates also proposes to adopt 2018 recorded capital expenditures instead of PG&E's 2018 forecasts. However, we find this to be addressed by Article 3.2 of the Settlement Agreement which requires PG&E to update all of its 2018 capital forecasts with 2018 recorded capital expenses.

Based on the discussions above, we find it reasonable to adopt the proposed capital amounts for IT and cyber and corporate security of $186.795 million for 2018, $199.361 million for 2019, and $223.052 million for 2020.

10.3. Summary

To summarize, the O&M and capital proposals in the Settlement Agreement relating to Shared Services and IT and Cyber and Corporate Security are reasonable and should be adopted subject to 2018 capital costs being updated with recorded capital expenditures for 2018 pursuant to Article 3.2 of the Settlement Agreement.

11. Human Resources

PG&E's Human Resources (HR) organization helps it attract and retain a qualified workforce. HR's main functions are to conduct workforce planning, ensure competitive compensation and benefits, oversee hiring and selection, engage and assess the employees' attitudes towards safety, and provide employees with developmental and training opportunities.

The HR Organization consists of four departments: the HR Operations Department; the HR Services Department; the Total Rewards Department; and the PG&E Academy Department.

HR Operations Department: conducts workforce planning, leads knowledge transfer and employee engagement activities, manages worker reporting and analytics processes, oversees job bidding and employment testing, and provides HR services to Company leadership and employees.

HR Services Department: is responsible for fostering a diverse and inclusive work culture, oversees PG&E's PowerPathway,[203] Master of Business Administration and internship programs, maintains relationships with the Company's three labor unions, and implements PG&E's HR programs and policies.

Total Rewards Department: designs, plans, implements, and administers PG&E's employee benefits and compensation programs.

PG&E Academy: develops and delivers technical and leadership training to employees.

PG&E presented its proposed O&M and capital costs for each of the four departments in Exhibit 207. However, in the Settlement Agreement, O&M costs for HR are grouped not according to the costs proposed for each of the four departments but are instead grouped into Department Costs, Companywide Expenses, and IT Expenses for the entire HR Department.

203 PG&E's PowerPathway Program aims to develop qualified candidates for PG&E's skilled craft positions.

Department Costs are costs attributable solely to one of the four departments while Companywide Expenses are costs which benefit the entire company as a whole. Meanwhile, IT Expenses are O&M expenses related to IT expenses that are attributable to the HR organization only. Thus, each of the four departments generally incurs both Department Costs and Companywide Expenses and if applicable, IT-related expenses as well. Our discussion of HR O&M costs will follow this grouping of costs as presented in the Settlement Agreement.

Under Article 2.7 of the Settlement Agreement, the settling parties agreed on a total HR forecast of $808.5 million[204] for TY2020 for O&M and capital expenses. PG&E's original total HR request was $924.290 million[205] which was later adjusted to $899.723 million[206] after various corrections, concessions, and adjustments were applied. The settlement amount represents a total reduction of $90.973 million from PG&E's requested amount consisting of a $1.203 million reduction in Department Costs, an $88.0 million reduction from PG&E's request for Short Term Incentive Payments (STIP) and a $1.973 million reduction for medical costs. The values for the reductions are exclusive of the labor escalation adjustments agreed-upon in the settlement which is discussed later in this section.

The table below shows PG&E's O&M and capital forecasts and settlement amounts for TY2020.[207] The values for PG&E's original forecast reflect the

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[204] This is a total company number that is allocated to the GRC using the GRC allocation factors specific to each component of HR.

[205] Exhibit 207 at 1-7.

[206] This amount excludes the labor adjustments adopted in the settlement.

[207] Settlement Agreement Appendix B at 1 to 4.

adjusted values presented in the joint comparison exhibit[208] but do not incorporate the labor escalation rates agreed-upon in the settlement. On the other hand, the settlement amount is inclusive of the labor escalation rates.

HR O&M and Capital TY2020	PG&E Forecast	Forecast Reduction	Settlement Amount
Department Costs	$77,326,000	$1,230,000	$76,096,000
Companywide Expenses	$817,925,000	$89,990,000	$727,935,000
IT Expenses	$2,059,000	$0	$2,059,000
Capital	$2,413,000	$0	$2,413,000
Total	**$899,723,000**	**$91,220,000**	**$808,503,000**

11.1. Department Costs

As stated above, HR Department Costs are costs incurred by the four departments under the HR organization. These include costs for salaries, materials and supplies, outside services, and training. PG&E submitted a Total Compensation Study performed by Willis Towers Watson.[209] The study evaluated PG&E's 2017 compensation and found the benefits and compensation to be competitive.

The table below shows PG&E's forecasts for Department Costs for each of the four HR departments and the settlement amount.

Department Costs	PG&E Forecast[210]	Forecast Reduction	Settlement Amount
HR Operations	$12,550,000	**$1,230,000**	**$76,096,000**
HR Services	$22,992,000		
Total Compensation	$5,616,000		
PG&E Academy	$36,167,000		
Total	**$77,326,000**		

208 The labor adjustments were presented in Volume 2 of the Joint Comparison Exhibit.

209 Exhibit 207 Chapter 7.

210 See Exhibit 207 Table 1-1 at 1-7.

The settlement includes a $1.203 million overall reduction to Department Costs. The reduction is not targeted to any specific costs of the four departments but is intended for affordability considerations. The remaining $0.027 million reduction reflects the adjustment to the labor escalation rates agreed-upon in the Settlement Agreement.

11.1.1. Labor Escalation

In Article 2.7.3 of the Settlement Agreement, the settling parties agree to adopt the labor escalation rates for the GRC period shown in Table 5.[211] Labor escalation rates reflect projected increases in costs for labor. The table below presents a summarized version of Table 5 and also shows the labor escalation rates for 2019 as a comparison.

Employee Category	**2019**	**2020 to 2022**
IBEW Represented Clerical	3.25%	3.00%
IBEW Represented Physical	3.25%	3.00%
ESC Represented	3.25%	3.00%
Service Employees International Union Represented	3.25%	3.00%
Non-represented Employees	3.27%	3.27%
Average Labor Escalation Rates: All Employees	3.26%	3.10%
Average Labor Escalation: Operating Units	3.26%	3.08%
Average Labor Escalation: A&G	3.28%	3.27%

The agreed-upon labor escalation rates for 2020 to 2022 results in adjustments to PG&E's forecasts that include labor-related costs such as salaries. PG&E's forecasts that are affected by the labor escalation adjustment in the settlement are reflected in Appendix B. For consistency, discussion of PG&E's forecasts shall reflect PG&E's adjusted forecast while discussion of settlement

[211] Settlement Agreement Table 5 at 26.

amounts shall incorporate the labor escalation adjustment from the settlement if applicable. All the adjustments from the agreed-upon labor escalation rates reflect a downward adjustment as compared to PG&E's labor escalation forecasts.

11.1.2. Positions of the Parties

The settlement applies a $1.203 million overall reduction in Department Costs for affordability reasons. The lower escalation rate agreed-upon also results in a reduction amounting to $0.027 million.

Cal Advocates originally proposed a $0.288 million reduction arguing that the Total Compensation Study is conducted each GRC period and costs should be amortized.

11.1.3. Discussion

Based on our review, Department Costs have been relatively flat the last five years and year-over-year increases have been primarily due to escalation of costs, especially labor-related costs. Thus, we find PG&E's proposed costs to be reasonable. Parties generally do not object to the year-over-year increases. We also find the labor escalation rates agreed-upon in the settlement to be reasonable and reflective of actual labor escalation rates. Parties actually agreed to a slightly lower escalation rate for the GRC period than the escalation rates for 2018 and 2019. We also find that the proposed escalation rates will enable PG&E's salaries to remain competitive and will not negatively impact the level of service provided by PG&E and its ability to perform its duties and obligations in a safe and reliable manner. Thus, the reduction of $0.027 million for Department Costs resulting from the labor escalation adjustment should be adopted. Cal Advocates objected to amortizing costs for the Total Compensation Study and originally recommended a reduction to PG&E's proposed forecast. However, we find that Cal Advocates' objection is adequately addressed by the $1.203 million reduction in the Settlement Agreement due to affordability considerations. In fact, the proposed reduction by Cal Advocates is less than the reduction in the settlement amount. Based on all of the above, we find the proposed forecast of $76.096 million for Department Costs reasonable and should be adopted.

The escalation factor adopted in this decision is reasonable in light of the entirety of the Settlement Agreement and the procedural record.

11.2. Companywide Expenses

As stated at the beginning of this section, Companywide Expenses are expenses which benefit the entire company as a whole. Costs are assigned to one of the HR departments but the benefit of the activities performed extends to the entire company or its employees. Discussion of Companywide Expenses shall focus on the expenses themselves and not the HR departments where the expenses are assigned.

The table below shows PG&E's forecast and the amounts adopted in the Settlement Agreement. The settlement total is inclusive of the labor escalation adjustment referred to in Section 11.1.1.

Companywide Expenses	PG&E Forecast	Forecast Reduction	Settlement Amount
Workforce Management	$18,822,000	$0	
Short-Term Incentive Program (STIP)	$173,395,000	$88,000,000	
Officer Compensation (deducted)	-($18,596,000)	$0	
Non-Qualified Retirement	$3,174,000	$0	
Health & Welfare	$496,136,000	$1,973,000	
Post-Retirement	$134,806,000	$0	
Other Benefits	$6,802,000	$0	
Tuition Refund	$3,390,000	$0	
Total[212]	**$843,158,000**	**$89,973,000**	**$727,935,000**

212 This is the total presented in Exhibit 207 Table 1-1 at 1-7.

Less adjustment and escalation	**$25,233,000**	n/a	n/a
Total[213]	**$817,925,000**	n/a	n/a

Workforce Management

PG&E's Workforce Management Transition Program provides financial and career resource support to employees whose positions are removed or redefined by the Company so that they can transition into new positions or outside job opportunities.

STIP

The STIP is an annual variable incentive pay plan that allows employees the opportunity to earn cash payments based on their individual performance and the company's achievement in reaching specified goals for the year.

Non-Qualified Retirement Plan

The Non-Qualified Retirement Plan provides non-qualified, non-trust fund pension benefits to employees whose tax-qualified benefits are limited by the Employee Retirement Income Security Act of 1974.[214]

Health & Welfare

Health & Welfare costs include costs for medical health plans, medical health accounts, dental benefits, vision benefits, and group life insurance.

Post Retirement

Post-Retirement Benefit costs fund programs for retirement and post-retirement benefits including the retirement savings plan or 401k, and post-retirement medical and life benefits.

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213 This represents the total forecast without the new labor escalation as presented in Appendix B of the Settlement Agreement at 3 to 4.

214 The forecast for Non-Qualified Retirement Plan also includes requested expenses for non-qualified pension benefits such as the Supplemental Executive Retirement Plan, the Retirement Excess Benefit Plan, and the Supplemental Retirement Savings Plan.

Other Benefits

Other Benefits fund expenses for employee relocation programs, emergency dependent care for emergency child and elderly care, employee service awards, and adoption reimbursements which allow employees to receive reimbursement of expenses related to adoption.

Tuition Refund

The Tuition Refund program provides employees with tuition reimbursement of up to $8,000 per year.

11.2.1. Reporting of Employee Benefits

The settling parties agree in Article 2.7.4 to allow PG&E's request to modify the requirements set in forth D.96-11-017 to allow PG&E to provide reports on its employee benefits plan in each GRC instead of annually as described in D.96-11-017.

11.2.2. Positions of the Parties

Cal Advocates originally recommended zero funding for six of the 12 STIP metrics[215] and 50 percent funding for the remaining metrics. Cal Advocates had also recommended 50 percent funding for Non-Qualified Retirement Plans and zero funding for Relocation Reimbursement, Dependent Care, and Adoption Reimbursement.

TURN originally recommended zero funding for the Earnings from Operations (EFO) metric for the STIP and 50 percent funding for the remaining metrics. This results in a 37.5 percent funding for STIP compared to PG&E's original request of $173.484 million.

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[215] *See* Exhibit 196 Table 15-8 at 16.

FEA is not a settling party and recommends that only 50 percent of PG&E's forecast for Service Awards be granted because this award benefits both ratepayers and shareholders.

11.2.3. Discussion

Cal Advocates had recommended using a four-year average from 2013 to 2016 to calculate costs because costs in 2017 were unusually high. However, a longer average such as a five-year average is meant to take into account these types of fluctuations and Cal Advocates provided insufficient evidence demonstrating why the base year value should simply be discarded from the average. Thus, we find PG&E's forecast, which the settlement adopts, to be reasonable.

For STIP costs, the settlement reduces the STIP forecast by $88.0 million which is approximately 50.72 percent less than PG&E's request. The metrics that comprise STIP regularly change but in many instances the Commission has found that particular STIP programs presented in large energy utility GRCs benefit both ratepayers and shareholders. In such cases, the Commission imposed reductions to proposed STIP forecasts. In PG&E's 2014 and 2017 GRCs, the Commission found that the STIP expenses benefit both ratepayers and shareholders and STIP costs should be shared between ratepayers and shareholders.[216] On the other hand, in D.19-09-051,[217] the Commission examined the metrics for STIP and excluded those that it found benefitted shareholders.

In this instance, our review of the STIP program shows that the current structure provides benefits to both ratepayers and shareholders. In deciding

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216 D.17-05-013 at 103-104; D.14-08-032 at 520.

217 D.19-09-051 is the decision in the latest GRC applications of SDG&E and SoCalGas.

how to address shared benefits between ratepayers and shareholders, we find it more reasonable in this case in light of the Settlement Agreement to consider an overall reduction to STIP costs rather than examine each metric individually as was done in D.19-09-051. This is in recognition of the various compromises and concessions arrived at among the settling parties consisting of many of the active parties in this proceeding. From our review, the proposed reduction of $88.0 million or approximately 50.72 percent from PG&E's proposal represents a fair compromise between different and opposing positions between PG&E and other parties, particularly Cal Advocates and TURN. The settlement amount is also within the range of outcomes presented by PG&E and parties such as Cal Advocates and TURN which had proposed zero funding for certain metrics and a 50 percent reduction in others. Based on the above, the proposed amount of $85.378 million for STIP[218] is reasonable and should be approved.

Other than the reduction to STIP costs, the only other reduction in Companywide Expenses proposed in the settlement is a reduction of $1.973 million in Health and Welfare Benefits. From our review, we find that parties generally did not oppose the forecast for Health and Welfare Benefits which appear reasonable in light of historical costs from 2013 to 2017.

Similar to our review of STIP, we find it more reasonable in this case to consider overall costs of Health and Welfare and Other Benefits rather than individual elements such as medical benefits, vision benefits, employee awards, etc. This is in light of the Settlement Agreement which represents various agreements including various compromises and concessions among the settling parties. Cal Advocates had objected to authorizing funding of certain benefits

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[218] This amount incorporates a $17,000 thousand labor escalation adjustment as shown in Appendix B of the Settlement Agreement at 3.

such as Relocation Reimbursement, Dependent Care, and Adoption Reimbursement and we consider the proposed reduction in Health and Welfare as a fair compromise that takes these objections into consideration. Overall, we find that the proposed reduction of $1.973 million represents a fair compromise between various positions of the settling parties on these issues. FEA, which is not a settling party, recommended 50 percent funding for Service Recognition Awards but we find that the overall reduction described above adequately addresses FEA's recommendation and concern regarding the issue. Therefore, we find the proposed reduction in the settlement of $1.973 million to Health and Welfare costs reasonably and adequately address issues and concerns relating to Other Benefits as well.

Based on the above discussion concerning Companywide Expenses, we find the settlement amount of $727.935 million reasonable and should be adopted.

TURN had expressed concern about PG&E's non-payment of STIP awards in 2018 as well as STIP awards that were at or below the projected STIP awards in 2016 and 2017. However, we find that the STIP forecast for TY2020 is a forward-looking forecast and so recorded costs may not always equal what was forecast. In addition, actual STIP awards in 2016, 2017, and 2018 reflect the STIP forecast in PG&E's prior GRC and not this GRC. In any case, this decision addresses the STIP forecast for this GRC cycle which we have thoroughly reviewed based on the available record in this proceeding.

11.3. IT Expenses

The settling parties agreed to adopt PG&E's proposed forecast of $2.059 million for IT expenses. The IT expenses support technology projects that support the HR department such as increased automation of employee-related processes and technology enhancements for the HR system.

We reviewed PG&E's proposed costs for TY2020 and find it to be reasonable and should be adopted. The expenses support routine IT enhancements for the HR organization. No party objected to the proposed costs.

11.4. IT Capital

The settlement adopts PG&E's proposed costs for IT capital projects of $5.377 million for 2018, $1.772 million for 2019, and $2.413 million for 2020. As discussed in section 15.2 of the decision, the settlement also states that the amount for 2018 is subject to the adjustment provided in Article 3.2 of the Settlement Agreement wherein PG&E's 2018 forecast of $5.377 million will be replaced with recorded 2018 costs.

The table below shows the IT capital expenditures for the HR departments.

HR IT Capital	2018	2019	2020
HR Operations	$3,359,000	$503,000	$881,000
Total Rewards	$0	$45,000	$51,000
PG&E Academy	$2,018,000	$1,224,000	$1,481,000
Total	**$5,377,000**	**$1,772,000**	**$2,413,000**

11.4.1. IT Capital Projects

HR Operations

Capital projects fall under the Built IT Apps and Infrastructure category and include three projects. The Enabling HR project will improve automation of employee-related processes while the other two projects are for upgrading an HR case management tool and deployment of a centralized system to track work-related information of all non-employee workers at PG&E.

Total Rewards

There are two projects and both fall under the Build IT Apps and Infrastructure category. The first project is an online tool to automate pay decisions for new hires and for employees changing jobs within PG&E. The second project is a tool to automate job and market analysis. Both projects will allow PG&E to comply with new California and San Francisco laws that require equal pay for substantially similar work and will aid in demonstrating compliance with future audits.

PG&E Academy

Projects for PG&E Academy include purchase of capital tools and equipment for PG&E's three learning facilities. Another project is for maintenance and upkeep of the learning facilities. Finally, there are three projects under Build IT Apps and Infrastructure: an application to assist in PG&E's apprenticeship programs; a project to enhance PG&E's training and enrollment processes and an upgrade to PG&E's Technical Information Library and Guidance Document Library to make them more accessible to employees on mobile devices.

11.4.2. Discussion

We reviewed the proposed IT capital projects and find the projects and settlement amounts for 2018, 2019, and 2020 reasonable. Most of the proposed projects fall under Built IT Apps and Infrastructure which are projects for enhancements and upgrades to existing systems or additions that will enhance or expand existing capabilities to systems used by the HR Organization. Parties have reviewed and do not oppose the justifications for the various IT projects.

Cal Advocates proposed using recorded costs of $4.509 million for 2018 which the settlement will ultimately adopt pursuant to Article 3.2 of the Settlement Agreement wherein PG&E's 2018 forecast will be replaced with recorded 2018 expenditures. Therefore, we find that the settlement amounts of $5.377 million for 2018, $1.772 million for 2019, and $2.413 million for 2020 should be adopted subject to the adjustment in Article 3.2.

11.5. Summary

To summarize, all revenue requirement and other proposals in the Settlement Agreement relating to HR are reasonable and should be adopted subject to the adjustment provided in Article 3.2 of the settlement.

12. Administrative and General (A&G)

This section discusses PG&E's Administrative and General (A&G) expenses for TY2020. A&G costs are "expenses of a general nature that are not directly chargeable to any specific utility function. These include general office labor and supply expenses as well as insurance, casualty payments, consultant fees, employee benefits, regulatory expenses, association dues, and stock and bond expenses."[219]

PG&E divides its A&G costs by the type of costs which are: Department Costs, Companywide Expenses, and IT Costs. These are discussed below as well as the impact of PG&E's affordability initiatives and RAMP on some subsections under A&G.

In Article 2.8 of the Settlement Agreement, the settling parties agree to a TY2020 forecast of $539.020 million for A&G expenses consisting of $168.006 million of department costs and IT costs, and $371.014 million for companywide expenses. This represents a reduction of $71.681 million from PG&E's original request of $610.701 million comprised of $177.078 million for department costs, $2.436 million for IT costs, and $431.187 million for companywide expenses. The

[219] Exhibit 157 at 1-1.

settling parties also agree to forecasted capital expenditures of $6.867 million for 2018, $8.530 million for 2019, and $8.322 million for 2020 subject to the adjustment provided in Article 3.2 of the Settlement Agreement. The above costs reflect the total gross company amount as opposed to the GRC net amount. Certain cost items include cost components for other Commission proceedings, FERC proceedings, and any separately-funded items and these are shown in Appendix B to the Settlement Agreement.[220] For such cost items, an allocation factor of approximately 83.09 percent is applied to determine the GRC net amount. The allocation factor is based on 2017 recorded adjusted O&M labor. Parties do not oppose the above allocation method and we find the applied allocation factor of approximately 83.09 percent reasonable. For consistency, discussion of A&G costs reflects the total company amount but at times may reflect the GRC amount when appropriate, such as when discussing relatively large costs like General Liability insurance for example.

12.1. Department Costs

Department Costs are for support services necessary for day-to-day operations.[221] The table below shows PG&E's proposed costs and the corresponding settlement amounts for A&G Department Costs (exclusive of IT and Companywide expenses). It should be noted that the settlement amounts apply and incorporate the labor escalation adjustments that the settling parties agree on which were discussed and found reasonable in the Human Resources section.[222] However, the amounts shown under PG&E's original forecast and the settlement reduction values do not reflect the labor escalation adjustments that

[220] Settlement Agreement Appendix B at 7 to 8.

[221] Exhibit 157 at 1-1 to 1-2.

[222] *See* section 11.1.1 to 11.1.3.

were agreed on by the settling parties. The organizations listed below also incur Companywide Expenses and as applicable, IT Costs. These costs are discussed in separate subsections.

Department Costs	PG&E Forecast	Settlement Reduction	Settlement Amount
Finance	$62,095,000	$10,899,000	$51,196,000
Risk and Audit	$11,463,000	$1,000	$11,462,000
Compliance and Ethics	$7,783,000	$1,000	$7,782,000
Regulatory Affairs	$15,627,000	$242,000	$15,385,000
Law Organization	$48,657,000	$2,000	$48,655,000
Corporation, Executive Offices and Corporate Secretary	$6,220,000	$1,000	$6,219,000
Corporate Affairs	$25,233,000	$362,000	$24,871,000
Total	**$177,078,000**	**$11,508,000**	**$165,570,000**

12.1.1. Finance

The Finance organization provides the necessary financial capabilities found in any large, publicly traded company.[223] The Finance organization is responsible for functions such as raising capital, communicating with investors, providing financial forecasts, filing financial statements with the Securities and Exchange Commission and other regulatory bodies, making necessary tax filings, and managing payment services for employees and vendors.[224]

12.1.2. Risk and Audit

Risk and Audit oversees PG&E's risk management and internal audit functions that help in managing key risks. The organization also assists LOBs in improving processes and controls to manage risks that are inherent in the utility's operations.

[223] Exhibit 157 at 2-1.

[224] *Ibid*.

12.1.3. Compliance and Ethics

Compliance and Ethics is responsible for enhancing and promoting a program designed to prevent and detect criminal conduct and promotes an organizational culture that encourages ethical conduct and a commitment to compliance with laws and regulations.[225]

12.1.4. Regulatory Affairs

Regulatory Affairs develops and implements regulatory policies concerning state and regulatory matters. It is also responsible for advocacy, rate design, data analysis, filings and management of complex regulatory cases and initiatives, and manages the implementation of final decisions issued by regulators.

12.1.5. Law Organization

The Law Organization is composed of the Law Department and the Office of the General Counsel to which the Law Department reports to. The Law Organization represents PG&E in all of its legal and regulatory matters and provides advice and counsel on legal matters.

12.1.6. Corporation, Executive Offices and Corporate Secretary

This group includes costs for the PG&E Corporation, the offices of the CEO and President, and the Corporate Secretary Department.[226] The CEO is responsible for executive leadership while the President oversees all of PG&E's functions and utility performance. The Corporate Secretary Department supports the Board of Directors, provides governance, reporting, and other necessary services.

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[225] Exhibit 157 at 4-1.

[226] Exhibit 157 at 7-1. Costs for Board of Directors fees and expenses are included in Companywide Expenses.

12.1.7. Corporate Affairs

The primary role of the Corporate Affairs organization is to communicate with customers, employees, government officials, media, and the public. Corporate Affairs informs customers about their PG&E service and assists in online access of services. It also provides information to customers, employees, and the public during emergencies and provides public safety information. It also creates awareness of services and programs, responds to media inquiries, and keeps local stakeholders and government officials apprised of key changes to operations in the community.

12.1.8. Positions of the Parties

The settlement amounts as well as PG&E's original request are shown in the table in section 12.1. The Settlement Agreement proposes reductions totaling approximately $11.508 million.

Cal Advocates originally recommended $0.266 million less than PG&E's request for Compliance and Ethics but agreed with the other amounts. The difference is associated with Cal Advocates' opposition to two analyst positions that will conduct regulatory support and awareness outreach.[227]

12.1.9. Discussion

The Settlement Agreement proposes reductions to Finance, Regulatory Affairs, and Corporate Affairs by $10.899 million, $0.242 million, and $0.362 million respectively.

The settlement proposes to adopt PG&E's proposed costs for Risk and Audit, Compliance and Ethics, Law Organization, and Corporation, Executive Offices, and Corporate Secretary less $1,000 or $2,000 reflecting labor escalation adjustments which we discussed in the preceding section on Human Resources.

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[227] Exhibit 198 at 6 to 7.

We reviewed the proposed settlement amounts for A&G Department Costs as well as the testimony presented by parties and any comments from non-settling parties and find the proposed amounts to be reasonable and supported by the record of the proceeding.

For the Finance organization, the settlement amount of $51.196 million is $10.899 million less than PG&E's original forecast of $62.095 million and $14.558 million less than 2017 adjusted recorded expenses in 2017. The reduced forecast is due in large part to labor savings from staffing reduction of around 82 Full Time Employees (FTEs) through natural attrition and reductions in business finance contracts and outside services. PG&E also states that it will implement several enterprise-wide affordability initiatives designed to find cost savings as part of the business planning process. These affordability initiatives are described in Exhibit 157 and include cost object standardization, optimizing the finance structure, and automation.[228] We support the above initiatives to reduce costs through efficiencies and find that this will not impair the Finance organization's ability to perform is functions.

The Settlement Agreement proposes a reduction of $0.242 million to the forecast for Regulatory Affairs. We reviewed the cost categories for Regulatory Affairs comprised of the VP office, Regulatory Relations, Regulatory Proceedings, and Rates and Regulatory Analytics. Based on the testimony presented, we find the TY2020 forecasts for Regulatory Relations and Rates and Regulatory Analytics reasonably reflect historical costs while the forecast for Regulatory Proceedings reflects the decrease in costs during 2017. For the VP office however, we find that a more modest increase from base year costs is

[228] Exhibit 157 at 2-20 to 2-21.

reasonable. PG&E proposed an increase of $0.352 million or from $2.249 million in 2017 to $2.601 million in 2020. However, the main cost driver for increased costs in Regulatory Affairs is labor escalation but this increase is somewhat offset by staffing reductions. However, as stated above, the Settlement Agreement proposes an overall reduction of $0.242 million to costs for Regulatory Affairs and while the reduction is not applied directly towards VP office costs, we find that this overall decrease in costs sufficiently addresses our concern regarding VP office costs. Therefore, we find the settlement amount of $15.385 million to be reasonable.

For Corporate Affairs, we support and find the reduction of $0.362 million from PG&E's original proposal of $25.233 million. PG&E's proposal is already $1.557 million or 6.2 percent less than base year costs. The reduction in costs is driven by staffing reductions through attrition although this decrease is slightly offset by labor escalation and increase costs for contracts and materials.[229] According to PG&E, the reduction in staffing levels is primarily attributable to reorganization and elimination of redundancy and we find that this will not impair Corporate Affairs from performing its required functions. Thus, we find the settlement amount of $24.871 million reasonable.

The Settlement Agreement adopts PG&E's proposed costs for Risk and Audit, Law Organization, and Corporation, Executive Offices, and Corporate Secretary subject to a $1,000 or $2,000 labor escalation adjustment. As stated above, the labor escalation adjustments are discussed and found reasonable in the section on Human Resources. With respect to the proposed costs, we find the costs for these organizations generally reflect a downward trend over the last

[229] Exhibit 157 at 8-11 to 8-12.

five years and all costs are less than base year costs as shown in Tables 16-5, 16-8, and 16-9 of Exhibit 198. The reductions in costs are due to decreased staffing levels (including several executive positions) being forecast for TY2020 and for Law Organization, the exclusion the costs for outside services and affordability initiatives designed to find cost savings.[230] We reviewed the proposed costs and based on the discussion above, we find the proposed costs in the Settlement Agreement for these three organizations reasonable.

The settlement amount for Compliance and Ethics also adopts PG&E's proposed costs and incorporates a $1,000 labor escalation adjustment. PG&E's proposed costs for TY2020 of $7.783 million is $1.206 million higher than base year costs due to labor escalation ($0.4 million), four new FTEs to improve a Compliance and Ethics modeling effort to reflect best practices ($0.6 million), and a projected increase in contract costs for third-party assessments. Cal Advocates originally opposed two of the four new FTEs discussed above stating that PG&E did not fully justify these additions but in the Settlement Agreement agreed to a funding amount that includes all four new FTEs. We reviewed the testimony presented and found the above increases to be reasonable and necessary and supported by the evidence presented. PG&E also explained the need for the four new FTEs and documented the functions that they will perform in Exhibit 159.[231] PG&E also included testimony that it conducted a cost benefit analysis for the new FTEs and added that the new FTEs offsets the need to engage the services of outside consultants for the work to be performed.[232] Based on all of the above,

[230] Exhibit 157 at 6-7 to 6-8.

[231] Exhibit 159 at 4-7 to 4-9.

[232] *Id* at 4-10 to 4-11.

we find the settlement amount of $7.782 million for Compliance and Ethics to be reasonable.

To summarize and as discussed above, we find the settlement amount of $165.570 million for A&G Department Costs reasonable and should be adopted.

12.2. Companywide Expenses

Companywide Expenses are costs incurred which benefit the entire company such as insurance premiums, settlements and judgments, fees, and other similar costs. The table below shows PG&E's original forecasts and the agreed-upon amounts in the Settlement Agreement.[233] Unlike Department Costs, Companywide Expenses do not have a labor component and so no labor escalation adjustments were applied to the settlement amounts. There are also no Companywide Expenses for Compliance and Ethics, Regulatory Affairs, and Corporate Affairs.

Companywide Expenses	PG&E Forecast	Settlement Reduction	Settlement Amount
Finance: Bank Fees	$5,492,000	$0	$5,492,000
Risk and Audit: Liability and Property Insurance	$385,815,000	$60,173,000	$325,642,000
Law Organization: Third party Claims	$37,983,000	$0	$37,983,000
Corporation, Executive Offices and Corporate Secretary: Director Fees and Expenses	$1,897,000	$0	$1,897,000
Total	**$431,187,000**	**$60,173,000**	**$371,014,000**

12.2.1. Bank Fees

Bank fees represent fees charged for depository, disbursement, custody, trustee-related services, and fees associated with PG&E's working capital

[233] Settlement Agreement Appendix B at 3 to 4.

facilities. PG&E's forecast was based on actual expenses in 2017 plus adjustments for capital structure changes and changes in contract terms.[234]

12.2.2. Liability and Property Insurance

Costs for Liability and Property Insurance are as follows:[235]

Insurance	PG&E Forecast	Settlement Reduction	Settlement Amount
Non-nuclear Property and Other Property	$22,725,000	$0	$22,725,000
Nuclear Property	$1,887,000	$0	$1,887,000
General Liability	$356,958,000	$60,173,000	$296,785,000
Directors and Officers Liability	$2,612,000	$0	$2,612,000
Nuclear Liability	$1,633,000	$0	$1,633,000
Total	**$385,815,000**	**$60,173,000**	**$325,642,000**

12.2.2.1. Property Insurance

Property Insurance includes non-nuclear property insurance, nuclear property insurance and other property insurance.

Non-nuclear Property insurance premiums provide coverage for the cost and repair of damaged PG&E non-nuclear property from hazards such as storms, earthquakes, and fires.

Nuclear Property insurance covers costs for nuclear property insurance premiums and in addition to the coverage from the above hazards, it also includes coverage for decontamination and stabilization following a nuclear event and for business interruptions at an undamaged facility.[236]

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234 Exhibit 157 at 2-23.

235 Settlement Agreement Appendix B at 3. The totals for Non-nuclear Property, General Property, and Directors and Officers Liability Insurance include corporate costs allocated to PG&E Corporation.

236 Exhibit 157 at 3-15 to 3-16.

Other Property insurance primarily includes insurance coverage for control of well[237] and aircraft.

12.2.2.2. Liability Insurance

General Liability insurance is for general commercial insurance. The majority of such insurance costs, or approximately $353.089 million, are for Excess Liability insurance to address third-party claims. Policies for Excess Liability insurance cover workers' compensation, and bodily injury and property damage liability for wildfire and non-wildfire causes. Costs also include approximately $5.155 million for other commercial insurance which provide coverage for crime, fiduciary liability, business travel, surety bonds, etc.

Directors and Officers Liability insurance provides coverage for claims alleging wrongful acts and breach of fiduciary duty by officers and members of the board of directors.

Nuclear Liability insurance is for claims relating to PG&E's nuclear property.

12.2.2.3. Risk Transfer Balancing Account (RTBA)

The settlement adopts PG&E's proposal to establish a new two-way RTBA to record General Liability insurance costs. The RTBA will record the difference between the amounts authorized in this GRC and actual costs of insurance premiums for coverage up to $1.4 billion.

PG&E also intends to obtain additional insurance beyond its forecast if the market presents a reasonable opportunity to do so and the settlement also adopts Cal Advocates' proposal that PG&E may file a Tier 2 advice letter to seek recovery of costs for coverage above $1.4 billion.

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[237] Control of well insurance covers costs associated with regaining control of a well, cleaning up pollution caused by a blowout, and re-drilling a well or restoring it to operation.

12.2.2.4. Self-Insurance

The settlement also adopts PG&E's proposals regarding implementation of self-insurance. The proposal is to invest unspent amounts authorized for General Liability insurance up to $1 billion into a self-insurance fund if competitively-priced insurance available in the market is limited. If self-insurance is not used during the policy period, the investments would remain in the fund in order to create a larger self-insured fund over time.[238] The cost of the investment(s) will be recovered through the RTBA subject to refund to customers for amounts not utilized. Any amounts invested into the fund that did not originate from unspent amounts authorized for General Liability insurance, or in excess of $1 billion, shall be recorded in the WEMA and recovery thereof shall follow the WEMA process. PG&E shall report on the condition of the self-insurance fund in its next GRC.

12.2.2.5. Recovery of WEMA Costs

The Settlement Agreement adopts PG&E's request to recover insurance premium costs of $66.944 million recorded in the Wildfire Expense Memorandum Account (WEMA). These costs were incurred from July 26, 2017 to August 1, 2018. The GRC portion of the above costs totaling $60.448 million will be amortized over a three-year period beginning January 1, 2020 while the remaining Commission jurisdictional portion of $6.497 million will be recovered by PG&E through the next available consolidated rate change following this proceeding.[239]

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[238] Settlement Agreement Article 2.8.3.3.

[239] Settlement Agreement at 28 to 29.

12.2.3. Law Organization

Costs for the Law Organization consists of Settlement and Judgment costs which are costs associated with litigation and Claims Payments to third parties which are associated with cases that did not proceed to litigation. The claims are generally for personal injury, property damage, or economic loss that results from PG&E's operations.

12.2.4. Director Fees and Expenses

These costs represent compensation for activities undertaken on behalf of PG&E by the PG&E board of directors and the PG&E Corporation board of directors. Compensation consists of retainer fees and director expenses.

12.2.5. Position of the Parties

The Settlement Agreement adopts all of PG&E's proposed costs except for General Liability insurance where a reduction of $60.173 million was agreed upon by the settling parties.

Cal Advocates originally proposed a reduction of $0.750 million less for Bank Fees using a four-year average from 2014 to 2017 because costs were for 2013 were significantly higher than in the following years.[240] Cal Advocates agrees with the establishment of the RTBA but proposed recovery of up to $1.4 billion instead of the $2 billion proposed by PG&E. For insurance premiums in excess of $1.4 billion, Cal Advocates proposed that either shareholders shoulder 50 percent of such costs or that PG&E be required to file a Tier 3 advice letter to seek recovery.

TURN originally proposed a reduction of $190.365 million to General Liability insurance based on removing costs associated with coverage for punitive damages estimated at $7.24 million and limiting to 50 percent PG&E's

[240] Exhibit 174 at 3.

request for both Excess Liability insurance ($353.5 million) and recovery of $67 million in excess liability insurance recorded in the WEMA.[241] TURN also initially opposed establishment of the RTBA and stated that recovery of excess costs should be addressed through the WEMA and submitted as an application.

FEA opposes the establishment of an RTBA and instead recommends that excess costs be tracked through a memorandum account.

JCCA supports the allocation of excess liability insurance as common costs as provided in Article 2.9.1(E) of the Settlement Agreement.

12.2.6. Discussion

The settlement amounts for Bank Fees, Third-party Claims, and Director Fees and Expenses adopt PG&E's original forecasts. We reviewed the testimony presented and find the amounts and forecast methodologies utilized reasonable. The forecast for Third party Claims utilized a four-year average from 2014 to 2017 which we find reasonable because of fluctuating costs. For Bank Fees and Director Fees and Expenses, costs were forecast using base year expenses plus adjustments because costs are expected to remain the same. Cal Advocates originally proposed excluding 2013 costs from historical averages but did not justify or explain why 2013 costs should be excluded other than stating that costs were high during this year. In contrast, PG&E provided sufficient justification for its forecast method of using base year costs as a basis as it explains that costs for TY2020 are expected to remain the same except for adjustments due to capital structure changes and changes in contract terms.

For Insurance costs, the Settlement Agreement also adopts PG&E's proposed costs for Non-nuclear, Nuclear Property, and Other Property insurance

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241 Exhibit 284 at 1.

costs as well as insurance costs for Director and Officers Liability and Nuclear Liability costs. We reviewed the PG&E's forecasts for these and find them to be reasonable and supported by the evidence. Forecast cost for Non-nuclear property insurance is approximately 30 percent higher than base year expenses of $16.572 million but the increase is a result of expanded coverage for earthquake risk[242] which we find reasonable. Cost for Other Property insurance is approximately four percent higher than 2017 costs which represents a reasonable increase while cost for Nuclear Property insurance is approximately 38 percent less than 2017 costs of $3.059 million due mostly to deductibles in PG&E's insurance premium. Parties do not oppose the forecasts for Nuclear Liability insurance and Director and Officers Liability insurance, and we find PG&E's forecast reasonable and supported by the evidence. Consistent with D.14-08-032, PG&E only included 50 percent of its total costs for Director and Officers Liability insurance.[243] PG&E adds that this insurance is necessary to attract qualified directors and officers.

Regarding costs for General Liability insurance, as shown in the table in section 12.2.2, the Settlement Agreement reduces PG&E's proposed costs by approximately $60.173 million.[244] We reviewed the testimony and arguments presented by parties and find that the settlement amount represents a fair compromise between party positions and are within the range of outcomes that were proposed especially by PG&E and TURN. As stated by PG&E, renewal

[242] Exhibit 157 at 3-15.

[243] Exhibit 157 at 3-21. D.14-08-032 is the decision addressing PG&E's 2014 GRC.

[244] In Article 2.8.3.1 of the Settlement Agreement, the settlement reduction is stated as $50 million and this refers to the GRC net amount which is 83.09 percent of the total gross company amount of $60.173 million.

costs for general liability insurance have gone up significantly in 2018. As shown in Table 3-3 of Exhibit 157,[245] $818 million in coverage cost $124 million in 2017 but coverage $1.4 billion in 2018 cost $360 million. PG&E's forecast considers market insights, continued exposure to wildfire risk and California's application of inverse condemnation law[246] with respect to damage from wildfires. On the other hand, TURN makes a good argument that insurance costs cover instances wherein PG&E might have acted negligently and that this benefits shareholders. Based on the above and without making specific findings as to the above parties' specific arguments, we find that the settlement amount represents a fair compromise between differing party positions concerning General Liability insurance costs.

Regarding the establishment of the RTBA, we agree that insurance costs for General Liability coverage has been difficult to predict in recent times because of market conditions and the recent wildfires in California. A two-way balancing account will also allow PG&E to address uncertainty in a timely manner and at the same time ensure that there is adequate insurance coverage. We therefore find it appropriate to apply two-way balancing treatment of costs authorized in this GRC for General Liability insurance consistent with the authority granted to establish the two-way Liability Insurance Premium Balancing Account in the TY2019 GRCs of SDG&E and SoCalGas.[247]

We also find appropriate the requirement for PG&E to file a Tier 2 advice letter for recovery of additional liability insurance costs in excess of $1.4 billion of

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245 Exhibit 157 at 3-18.

246 Under this principle, California law holds utilities liable for damage caused by their equipment whether the utility was negligent or not.

247 D.19-09-051 OP 7(b) and OP 8(c).

coverage. $1.4 billion represents the amount of coverage for the $356.958 million that the settling parties agreed to. PG&E originally sought to obtain $2 billion worth of General Liability insurance and $1.4 billion represents a fair compromise with the proposals from other parties. In addition, Tier 2 review of additional insurance expenditure allows the Commission to review other types and levels of coverage not presented in this GRC but also balances PG&E's need to act quickly where it finds need to purchase additional insurance by limiting PG&E's exposure to increased risk for a significant period while waiting for approval of an application.

However, for larger expenditures above the amount authorized in this decision, we find it reasonable to modify the Settlement Agreement and require the filing of an application to request recovery of expenditures in excess of 130 percent of the authorized amount of $356.958 million. We also expect PG&E to act prudently with respect to the purchase of additional insurance using funds in excess of what is authorized in this decision. PG&E should obtain additional insurance beyond its forecast if the market presents a reasonable opportunity to do so and if competitively-priced insurance is available. The amount of insurance coverage compared to the cost of such coverage should also be reasonable and PG&E should explain instances wherein the cost of insurance coverage differs greatly from the forecasts presented and authorized in this decision.

We reviewed the proposals concerning the implementation of a self-insurance fund for unspent amounts authorized for General Liability insurance and do not oppose the mechanics and principles set forth in the Settlement Agreement concerning the proposed self-insurance fund. PG&E intends to purchase insurance prudently and seeks to avoid insurance that cost more than

50 percent of the coverage provided and avoid risk financing deals.[248] As explained by PG&E, the fund presents a better option than purchasing high-priced insurance. Amounts invested into the fund will come from amounts that are authorized in this GRC and recovery of any excess funds invested shall be subject to Commission review. The Commission will also have an opportunity to review the status of the fund in PG&E's next GRC to determine if the fund should continue and whether any unspent funds should instead be returned to ratepayers with interest.

The above review of insurance costs is reflective of current conditions and takes into account recent wildfires in California and testimony that insurance costs have generally increased and have been harder to predict.

With respect to the recovery of $66.944 million recorded in the WEMA as authorized in D.18-06-029[249] we find that the costs tracked represent actual incremental wildfire-related costs that were incurred from July 26, 2017 to August 1, 2018 in excess of what are included in rates. Authorized costs from PG&E's 2017 GRC were based on 2014 recorded costs and wildfire-related insurance costs have gone up during the period above. The costs were reviewed and parties do not object to the amounts recorded. Based on the above, we find it reasonable to recover the above costs as well as the proposed amortization of the GRC-related amount of $60.448 million over a three-year period beginning January 1, 2020 with the remaining Commission jurisdictional portion of $6.497 million to be recovered through the next available consolidated rate change.

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[248] Exhibit 159 at 3-27.

[249] D.18-06-029 OP 1 to OP 4.

12.3. IT Expenses

The table below reflects the associated IT expenses for the seven organizations that comprise A&G.

Department Costs	PG&E Forecast	Settlement Reduction	Settlement Amount
Finance	$1,211,000	$0	$1,211,000
Risk and Audit	$249,000	$0	$249,000
Compliance and Ethics	$475,000	$0	$475,000
Regulatory Affairs	$396,000	$0	$396,000
Law Organization	$4,000	$0	$4,000
Corporation, Executive Offices and Corporate Secretary	$0	$0	$0
Corporate Affairs	$101,000	$0	$101,000
Total	**$2,436,000**	$0	**$2,024,000**

Parties did not object to PG&E's proposed costs and the Settlement Agreement adopts PG&E's proposed costs but applies the labor escalation adjustments adopted in the Settlement Agreement as discussed in the Human Resources chapter.

The IT projects are for support technology enhancements that routinely maintain the technology systems of the above departments and for maintenance costs. We reviewed the PG&E's proposed costs for TY2020 and find them to be reasonable. Costs are for regular IT upgrades that are undertaken to update and enhance various IT-related technology and support systems. The proposed costs are $3.562 million less than base year expenses. As discussed in the Human Resources section, we find the escalation adjustments to be reasonable and therefore find that the settlement amount of $2.436 million for IT Expenses reasonable and should be adopted.

12.4. IT Capital

PG&E's proposed costs for IT capital projects are $6.867 million for 2018, $8.530 million for 2019, and $8.322 million for 2020. The Settlement Agreement adopts PG&E's proposed costs. As discussed in section 15.2 of the decision, the amount for 2018 is subject to adjustment provided in Article 3.2 of the Settlement Agreement wherein PG&E's 2018 forecast of $6.867 million will be replaced with recorded 2018 costs.

12.4.1. IT Capital Projects

Finance Projects

Capital projects include the Financial Forecasting Model Optimization which is to improve efficiency and accuracy of business and financial planning, the PowerPlan Upgrade which is an asset and tax accounting system, the Cross Application Time Sheet project which will replace PG&E's current platform, and the Systems and Applications (SAP) Financial Upgrades which are for upgrades and enhancements to PG&E's SAP system.

Risk and Audit Projects

PG&E proposes one capital project which is the Market and Credit Risk Management Project which will address basic maintenance and upgrade cycles and will mitigate risks associated with activity management in the energy commodity markets. The project includes integrated framework enhancements and risk management enhancements.

Compliance and Ethics

Projects include the Enterprise Compliance and Risk Management Tool Integration project which will establish a comprehensive and uniform capability to manage compliance and risk management which is currently accomplished on an LOB-by-LOB basis.[250] There will also be two projects completed by 2020: the Mobile Enablement for Guidance Documents which will add more mobile

[250] Exhibit 157 at 4-11.

capabilities to the existing system; and the Enterprise Compliance Tracking System Ethics Module Replacement project which tracks and manages employee conduct.

Regulatory Affairs

There are two projects under Regulatory Affairs, the Model Platform and Data Integration project and the Rate Architecture and Analytics project. The first project will integrate two platforms that leverage smart meter data while the latter project will build rate models that will bolster PG&E's analytical functions.

There are no capital projects for the Law Organization, Executive Office and Corporate Secretary, and Corporate Affairs.

12.4.2. Discussion

We reviewed the proposed IT capital projects and find the projects and settlement amounts for 2018, 2019, and 2020 reasonable. Most of the proposed projects are for enhancements and upgrades to existing systems and the additions will increase or enhance existing capabilities or consolidate related functions. Cal Advocates proposed using recorded costs of $5.335 million for 2018 and although the settlement adopts PG&E's forecast costs, Article 3.2 of the Settlement Agreement also provides that the 2018 forecast will be replaced with recorded 2018 expenditures. We find no issue in adjusting the 2018 forecast to reflect recorded costs in 2018.

Therefore, the settlement amounts of $6.867 million for 2018, $8.530 million for 2019, and $8.322 million for 2020 should be adopted subject to the 2018 amount being adjusted to $5.335 million to reflect recorded 2018 costs pursuant to Article 3.2 of the settlement.

12.5. Summary

To summarize, all revenue requirement and other proposals in the Settlement Agreement relating to A&G are reasonable and should be adopted subject to the adjustment provided in Article 3.2 for 2018 capital expenditures.

13. Results of Operations

PG&E's Results of Operations (RO) exhibit presents PG&E's forecasted revenue requirement for its electric generation, electric distribution, and gas distribution operations. The forecasted revenue requirement is calculated through a computer model, called the RO model.

This section discusses the major components of the RO model. Specifically, we will discuss 1) Rate Base, 2) Taxes, and 3) Other Operating Revenues. We will also discuss some of the major components of Rate Base, namely Utility Plant, Working Capital, Customer Advances, Customer Deposits, and Depreciation Reserve.

We will also discuss the cost allocation factors, which are another major component of the RO model. The cost allocation factors determine how PG&E's companywide costs are divided into the electric distribution, electric generation, and gas distribution functions.

13.1. Rate Base

PG&E's Rate Base is the value of the assets PG&E owns and uses to provide utility service, less the depreciated value of the assets. The Rate Base represents the capital investments PG&E has made in utility plant. PG&E earns a return on the capital investments recorded in rate base.

The major components of Rate Base are Utility Plant, Working Capital, Customer Advances, Customer Deposits, Depreciation Reserve, and Deferred

Taxes.[251] The RO model takes these components, as well as the capital investments the Commission authorizes, to calculate PG&E's Rate Base. The settlement agreement adopts a forecast of $29.463 billion for PG&E's 2020 Rate Base.[252]

We review and discuss the reasonableness of the settlement's forecasted $29.463 billion Rate Base through discussing the reasonableness of each major element of Rate Base, namely Utility Plant, Working Capital, Customer Advances, Customer Deposits, and Depreciation Reserve.

13.1.1. Utility Plant

Utility plant is the value of undepreciated assets that PG&E uses to provide service. These include assets that are currently used and useful in providing utility service to customers and the capital investments PG&E is authorized to add to its plant (capital additions). It is the sum of assets that the Commission authorized PG&E to recover and the capital additions PG&E requests for authority to add to the Utility Plant.

We review the reasonableness of capital expenditures that PG&E requests to add to Utility Plant in various other sections of this decision, such as Energy Supply, Gas Distribution, and Electric Distribution, among many others. Using the plant assets that the Commission previously authorized and the capital additions we authorize in this decision, the RO model calculates the balance of the Utility Plant.

13.1.2. Working Capital

Working Capital consists of 1) Working Cash and 2) Materials and Supplies (Materials) costs. The settling parties agree to a $59 million revenue

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[251] Exhibit 71 at 1.

[252] Response of PG&E to Administrative Law Judges' Ruling, Appendix D at 2.

requirement reduction related to Working Capital expenses, with a $33 million reduction pertaining to Working Cash expenses and $26 million reduction pertaining to Materials Costs. We discuss Working Cash and Materials in more detail below.

13.1.2.1. Working Cash

Working Cash is composed of working cash required for day-to-day operations and cash needed to pay operating expenses in advance of receiving payments from customers. To compensate investors for permanently funding working cash, working cash is included as a component of rate base.

PG&E's working cash is calculated in the following manner:

Working Cash =

Required Bank Balances + Special Deposits and Working Funds

+ Other Receivables + Net Prepayments + Deferred Debits

Less: Working Cash Capital not Supplied by Investors + Goods Delivered to Construction Sites + Accrued Vacation

Add: Difference between lag in collections and lag of expense payments.

For 2020, PG&E requested working cash of $1,083 million, which consisted of $228.9 million for gas distribution, $378.7 million for electric generation, and $474.6 million for electric distribution.[253] PG&E stated that its method for computing working cash is consistent with the Commission's SP U-16 and requested that the Commission adopt PG&E's method for calculating working cash.

13.1.2.1.1. Settlement Agreement

The settlement modifies PG&E's proposal in two areas of Working Cash that parties contested, namely "Other Receivables" and PG&E's revenue lag. It

[253] Exhibit 26 at 380.

also adopts PG&E's original proposal on two other issues that parties contested, which are the HCP department-specific deferred debits and deductions for "Goods Delivered to Construction Sites."

Specifically, the settling parties agree to a $33 million revenue requirement reduction related to Working Cash expenses, which consists of:

1. $23 million revenue requirement reduction for Other Accounts Receivable related to non-recurring items such as insurance proceeds for the Butte fire; and
2. $10 million revenue requirement reduction for the revenue lag associated with the California Climate Credit.

The settling parties recommend that all other PG&E proposals regarding other account receivables, deferred debits, and the computation of revenue lag should be adopted.[254]

13.1.2.1.2. Discussion

We discuss each element of working cash below, which are 1) Special Deposits and Working Funds, 2) Other Receivables, 3) Prepayments, 4) Deferred Debits, 5) Goods Delivered to Construction Sites, 5) Accrued Vacation, and 6) Cash Required due to Time Lags.

In this chapter, PG&E presents its forecasts both for the GRC, which are the costs it requests to recover in this proceeding, and for the Total Company (TC), the costs that are recovered in rates under the jurisdictions of the Federal Energy Regulatory Commission (*e.g.* transmission expenses) and the CPUC. For

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[254] PG&E's proposals include the concessions PG&E made in rebuttal testimony. In rebuttal testimony, PG&E agreed to Cal Advocates' recommendations to remove GHG compliance allowances from Other Receivables (a $34.050 million reduction), Cal Advocates' adjustments to Accrued Vacation (a $16.7 million reduction), and TURN's recommendations for adjustments to a number of prepayment accounts (a $ 30.3 million reduction). *See* Exhibit 72, Chapter 13, Attachment A at 1-2.

working cash, PG&E generates the GRC forecast by applying an allocation percentage to the TC forecast.

13.1.2.1.2.1. Special Deposits and Working Funds

Special deposits include deposits with federal, state, or municipal authorities to ensure that PG&E can fulfill obligations. PG&E forecasts special deposits to be zero in 2020.

Working funds include the petty cash PG&E uses to make change for customers who make cash payments at the local offices. Using the average of 12 month-end balances for the 2017 recorded year, with an adjustment for inflation using the A&G escalation rates,[255] PG&E forecasts working funds to be $155,000 (TC) in 2020.[256]

No parties oppose PG&E's forecast for Special Deposits and Working Funds. The settlement adopts PG&E's forecasts.

The settlement's proposal of adopting PG&E's forecasts for Special Deposits and Working Funds, which are derived using the average of recent recorded data and adjusted for inflation, is reasonable and is adopted.

13.1.2.1.2.2. Other Receivables

Other receivables are non-interest-bearing accounts that are not part of the revenue that would affect the revenue lag, such as non-energy billings like main-line extensions and paid insurance claims. PG&E's forecasts Other Receivables by using the average of 12 month-end balances for the 2017 recorded

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[255] Exhibit 80 at 13-3.

[256] Exhibit 90 at 13-9.

year, with an adjustment for inflation using the Administrative and General escalation rates.[257]

Cal Advocates proposed reducing "Other Receivables" by $226.7 million (GRC forecast), or $256.5 million in TC forecast.[258] (Cal Advocates presented their recommendations for the individual line items in TC forecasts and their aggregate recommendations in terms of the GRC forecasts. We are discussing Cal Advocates' recommendations in TC forecasts.)

Cal Advocates' $256.5 million (TC forecast) reduction in "Other Receivables" consists of a $238.7 million (TC) reduction in non-recurring items and a $17.8 million (TC) reduction for non-energy billings. Cal Advocates recommended the $238.7 million (TC) reduction for non-recurring items (such as for insurance proceeds for the Butte fire, a contract with the Federal Aviation Administration for energy efficiency improvements and demand-response services, and a mutual aid for Florida Power and Light for repair assistance given for Hurricane Irma, etc.).[259, 260] Cal Advocates argued that, according to the Commission's SP U-16, working cash is for funds that are permanently committed to financing the lag between operating expenses and the receipt of revenues, and should thus be forecasted based on permanent commitments rather than non-recurring one-time commitments made during the recorded base year.[261]

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[257] Exhibit 80 at 13-3.

[258] Exhibit 235 at 17.

[259] Exhibit 235 at 17.

[260] Exhibit 204 at 17.

[261] Exhibit 235 at 19.

TURN agreed with Cal Advocates' recommended reductions of $238.7 million (TC) for non-recurring items. TURN further noted that the Commission has not yet determined whether ratepayers should pay for the $175.3 million (TC) in insurance proceeds for the Butte fire.[262] TURN also argued that ratepayers should not be responsible for funding the $1.5 million (TC) of mutual aid to Florida Power and Light.

PG&E responded that the parties' recommendation of a zero allowance for non-recurring other receivables is unreasonable, because non-recurring receivables occur in any given year, even though the type of non-recurring receivables may vary from year to year.[263]

In addition, Cal Advocates recommended reducing "Other Receivables" by $17.8 million (TC) for non-energy billings, such as mainline extensions. Cal Advocates argued that PG&E's forecasting method of escalating the 2017 recorded data is inappropriate because the 2017 data was abnormally higher than the recorded data in the previous years. Instead, Cal Advocates proposed using a five-year average. In response, PG&E argued that using the 2017 recorded data followed the guidance of SP U-16.[264] Furthermore, according to PG&E, the recorded data in 2018 is higher than the recorded 2017 data, which is evidence of the increasing trend in non-energy billings. PG&E explained that non-energy billings had been increasing because work for the relocation of gas or electric facilities and for joint pole usage with wireless carriers had been increasing.

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[262] Exhibit 204 at 17 to 18.

[263] Exhibit 72 at 13-16 to 13-17

[264] Exhibit 72 at 13-9 to 13-12.

The settlement reduces the revenue requirement associated with the "Other Receivables" forecast by $23 million, as stated above. Cal Advocates initially recommended reducing the forecast for "Other Receivables" by $226.7 million (GRC forecast), or $256.5 million in TC forecast, by lowering the forecasts for non-energy billings and removing non-recurring items from Working Cash. TURN supported Cal Advocates' removal of non-recurring items. While the settlement does not explicitly point to the specific items that parties agree to reduce and the extent of the reduction, the reduction represents a reasonable compromise of the parties' positions. Even though there are non-recurring receivables in any given year, the amount and nature of non-recurring receivables differ from year to year. Given the fluctuating nature of non-recurring receivables, PG&E's forecast, which is calculated based on the 2017 recorded data, does not produce a reasonable forecast, because the TY forecast cannot be accurately calculated based on one year of recorded data. Yet, it is unreasonable to assume that PG&E will not incur any non-recurring receivables in the TY. Therefore, the settling parties' proposed forecast, which represents a reasonable compromise between the parties' positions, is a fair outcome and forecast. We therefore consider it reasonable and adopt the settlement's proposed forecast.

13.1.2.1.2.3. Prepayments

Working cash prepayments are the amount of capital required from investors to pay for insurance premiums, software license fees, taxes, and other goods and services in advance of the coverage or service period. PG&E forecasts $93.785 million (TC) in prepayments for 2020.[265]

[265] PG&E-10, Workpaper 13-19, line 7

The settling parties agree to adopt PG&E's forecast. After reviewing PG&E's forecasts on prepayments, we find the settling parties' proposal to adopt PG&E's forecast to be reasonable.

13.1.2.1.2.4. Deferred Debts

Deferred debits are the expenses that are in the process of amortization, clearing account amounts, and unusual expenses that are not included in other current asset accounts. There are two categories of deferred debits: Company-wide deferred debits and Department-specific deferred debits. Company-wide deferred debits are unidentified receipts and other non-interest bearing amounts that consistently maintain a credit balance. Department-specific deferred debits specifically refer to the costs of PG&E's Habitat Conservation Plan (HCP). For both categories of deferred debits, PG&E calculates its forecasts using the average of 12 month-end balances of the 2017 recorded year, adjusted for inflation with A&G escalation rates.

PG&E forecasts Company-wide deferred debits to be $11.035 million (TC).[266] PG&E's forecast for Company-wide deferred debits was not contested by parties and is adopted by the settlement. PG&E's forecast for Company-wide deferred debits, which was derived based on the average of recent historical data, and as recommended by the settling parties, is reasonable and is adopted.

PG&E initially forecasted Department-specific deferred debits to be $61.067 (TC) million.[267] Cal Advocates recommended excluding the prepayments of HCP costs in PG&E's forecast of department-specific deferred

[266] PG&E-10, Workpaper 13-28, line 14.

[267] PG&E originally requested $35.986 million for HCP deferred debits, but PG&E agreed to reduce its request by $8.094 million to $27.892 million to account for HCP deferred debits that will be transferred to plant or operating expenses during the 2018-2022 period. *See* Exhibit 72 at 13-22 to 13-24.

debits. Arguing that the HCP costs fund projects that are not used and useful, Cal Advocates opposed funding HCP with Working Cash and proposed funding the HCP projects with short-term debt instead. In response, PG&E argued that the concept of disallowing cost recovery of plant that is not used and useful applies only to new utility plant but not working cash. PG&E asserted that the prepayments for HCP costs qualify under the FERC uniform system of accounts and SP U-16 guidelines to be considered as deferred debits.[268] Specifically, PG&E argued that the HCP costs meet the conditions of deferred debits because they are miscellaneous costs, in the process of being amortized, and are not included in other current asset accounts.[269]

The settlement adopts PG&E's treatment of prepayments for HCP costs as deferred debits. We agree with PG&E that the HCP costs meet the criteria of deferred debits under the guidance set forth by the FERC uniform system of accounts and SP U-16. Therefore, it is reasonable to include HCP costs as deferred debits. Thus, we adopt the settling parties' recommendation of using PG&E's forecast for department-specific deferred debits.

13.1.2.1.2.5. Goods Delivered to Construction Sites

"Goods Delivered to Construction Sites" is the cost of contractor-supplied goods delivered to a construction jobsite. As part of Construction Work In Progress (CWIP), this cost is deducted from working cash capital because the goods are paid for after the Allowance for Funds Used During Construction begins to accrue. PG&E forecasts the Goods Delivered to Construction Sites to be $28.505 million (TC) in 2020, based on the recorded 2017 daily cost for these

268 Exhibit 72 at 13-23.

269 *Ibid.*

goods, multiplied by the cost lag, and adjusted for growth in CWIP from 2018-2020.[270]

Cal Advocates recommended increasing the forecasted deductions for Goods Delivered to Construction Sites by $2.5 million (TC). Cal Advocates opposed PG&E's forecasting methodology and proposed to derive the forecast by escalating the 2018 recorded CWIP by the 2019 and 2020 escalation factors. PG&E asserted that using the 2017 recorded data follows the SP U-16 guidance of forecasting using the base year. PG&E also argued that, since there is no evidence that CWIP will grow from 2017 to 2020, it is inappropriate to escalate CWIP by the 2019 and 2020 escalation factors.[271]

The settlement adopts PG&E's forecasted deductions for Goods Delivered to Construction Sites. PG&E's forecast uses the 2017 recorded data, following SP U-16 by using the base year. Since parties did not raise any special circumstances that warrant deviating from SP U-16, adopting PG&E's forecasting method, as supported by the settlement, is reasonable. We therefore adopt the settling parties' recommendation to use PG&E's forecasted deductions for Goods Delivered to Construction Sites.

13.1.2.1.2.6. Accrued Vacation

Accrued vacation, according to the Commission's SP U-16, are the "monies accrued through operating expenses for future liabilities which the utility has available until payments to employees for vacation… are made."[272] They are a deduction from a utility's operational cash requirement. PG&E forecasts accrued vacation by multiplying a vacation accrual factor, derived based on base year

270 Exhibit 80 at 13-6.

271 Exhibit 72 at 13-26.

272 CPUC Standard Practice U-16, Chapter 3, paragraph 25 at 1 to 9.

data, with its forecasted test year labor.[273] PG&E's forecasting methodology for accrued vacation was not contested by the parties and is adopted by the settlement.

Applying a vacation accrual factor of 0.1266 to the labor forecast,[274] the settlement adopts a forecast of $219.065 million (TC) ($173.283 million GRC) for accrued vacation. PG&E's forecasting methodology, as recommended by the settling parties, is reasonable. Thus, we adopt the settlement's forecast for accrued vacation.

13.1.2.1.2.7. Working Cash Capital Not Supplied by Investors

"Working cash not supplied by investors" includes items such as certain tax collections payable and employee withholdings for medical, dental, and vision plans. It is a deduction to working cash. Using a 4-year average, adjusted for inflation using A&G escalation rates, PG&E forecasts Working cash not supplied by investors to be $11.466 million (TC).

PG&E's forecast for Working cash not supplied by investors was not contested by the parties and is adopted by the settlement. PG&E's forecast, as recommended by the settling parties, is reasonable and is adopted.

13.1.2.1.2.8. Cash Required Due to Time Lags

Additional working cash capital is required to pay expenses in advance of the receipt of offsetting revenues. This component involves weighting the utility's expense lags into an overall average and subtracting this amount from the calculated revenue lag.

273 Exhibit 80 at 13-5.

274 Exhibit 89 at 13-55.

PG&E forecasts its revenue lag to be 47.69 days, based on the 2017 recorded data.[275] Opposing PG&E's forecast methodology, Cal Advocates proposed a revenue lag of 44.40 days. Cal Advocates recommended forecasting the revenue lag by first taking the five-year average of the recorded revenue lag, and then deducting 0.96 days from the average to account for the return of GHG revenues to customers. Cal Advocates argued that a five-year average removes the fluctuations in revenues, or customer bills, due to abnormal weather conditions and any other such factors. In addition, Cal Advocates argued that PG&E did not account for the GHG climate credits appropriately when forecasting the revenue lag. According to Cal Advocates, PG&E receives GHG climate credits for the sale of consigned cap-and-trade compliance instruments and returns the credits to customers at the time the customer bill is calculated. Cal Advocates opposed how PG&E recognizes the return of the GHG climate credits refunds at the time the customers pay their bills, rather than when the customer bill was calculated, in forecasting its revenue lag. Therefore, Cal Advocates argued that the revenue lag needs to be re-weighed to account for the timing difference. Cal Advocates noted that SCE, in its GRC, acknowledged this issue and agreed to re-weigh its revenue lag accordingly.

TURN supported Cal Advocates' recommendations on PG&E's revenue lag, explaining that the GHG revenue lag was an issue that TURN raised in the SCE GRC. TURN noted that this proposed adjustment would reduce PG&E's Rate Base, which would subsequently reduce PG&E's revenue requirement by $10.3 million.[276]

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275 Exhibit 235 at 19-33 to 19-38.

276 Exhibit 204 at 21.

PG&E opposed Cal Advocates' method of using a five-year average to forecast the revenue lag, arguing that PG&E's forecast method of using the 2017 recorded data follows SP U-16's guidance. PG&E stated that there are currently no special circumstances that would justify deviating from SP U-16's guidance. Further, PG&E asserted that, because the 2018 recorded revenue lag is similar to the 2017 recorded lag, the 2017 recorded revenue lag is more consistent with current day lag conditions, as compared to Cal Advocates' five-year average.[277]

PG&E also opposed Cal Advocates' and TURN's proposal to reduce the revenue lag by 0.96 days for the GHG climate credit refunds. PG&E argued that its accounting for GHG consignments is different than that of SCE. PG&E also argued that, because the timing of the GHG transactions leads to offsetting, the GHG transactions have an insignificant impact on PG&E's revenue lag.[278]

The settlement adopts a revenue requirement reduction of $10 million for adjustments to the revenue lag. The settlement effectively adopts Cal Advocates' and TURN's recommendations to recognize the return of GHG climate credit at the time when customer bills are generated. We agree with the settling parties that it is appropriate to adjust the revenue lag to account for the timing difference of when the GHG climate credit refunds are recognized. Thus, the settlement's proposed revenue requirement reduction of $10 million to account for revenue lag adjustments related to the GHG climate credit refunds is reasonable and adopted.

The settlement also adopts PG&E's method of using the recorded 2017 revenue lags to forecast the TY2020 revenue lag. PG&E's method is based on the

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[277] Exhibit 72 at 13-27 to 13-28.

[278] Exhibit 72 at 13-33 to 13-36.

guidance of SP U-4, which uses the base year recorded data as the forecast. Because the 2018 recorded lag is similar to the 2017 recorded lag, we agree that current day lag conditions have not significantly changed since 2017 and thus find that there is no justification for using a different method, other than the one prescribed by SP U-16. The settlement's adoption of PG&E's TY 2020 revenue lag, adjusted for the GHG climate credit refund, is reasonable and adopted.

13.1.2.2. Materials and Supplies Costs

Materials and Supplies Capital (Materials) costs are for tools and equipment that support PG&E's maintenance and construction activities. PG&E presents its entire forecast for the Materials costs in the Shared Services section as part of its materials management operation. See Section 10.1.3.3 (Materials Capital) for more details.

In this section, we discuss the portion of Materials costs that are a part of PG&E's working capital. As discussed previously, PG&E's forecast for working capital is made up of Working Cash and Materials costs.

13.1.2.2.1. Settlement Agreement

The settling parties agree to a $26 million revenue requirement reduction for the GHG Asset and Liability Balances, which is the only portion of Materials costs parties opposed as part of PG&E's Working Capital forecasts. The parties also agree that carrying costs of GHG compliance instruments, or the costs PG&E incurs for holding inventories of GHG compliance instruments, should be addressed in PG&E's Energy Resource Recovery Account (ERRA) proceedings and Annual Gas True up advice letters.

13.1.2.2.2. Positions of the Parties

Parties did not oppose PG&E's forecasted Materials costs except for PG&E's proposal to forecast GHG compliance instrument inventory costs as part of Working Capital. PG&E procures GHG compliance instruments under the California Air Resources Board (CARB)'s cap-and-trade program as a way of complying with its GHG emissions requirements obligations.[279]

Cal Advocates recommended that PG&E recover the carrying costs of GHG compliance instruments at the short-term debt rate in the ERRA proceedings. Because the Commission has a long-standing policy of authorizing the cost recovery of GHG compliance instruments at the short-term debt rate through the ERRA, and carrying costs for GHG compliance instruments share the same risk profile as GHG compliance instruments, Cal Advocates argued that carrying costs for GHG compliance instruments are more appropriately recovered through the ERRA, rather than with equity financing in Rate Base through the GRC.[280] Cal Advocates further argued that the balancing account treatment through the ERRA mechanisms encourages PG&E to pursue cost-effective procurement strategies for ratepayers.[281]

In response, PG&E argued that short term financing is for debt that must be paid off within 12 months. Because CARB regulations require PG&E to purchase GHG compliance instruments three years prior to using the allowances, PG&E asserted it is inappropriate to finance the carrying costs of the GHG compliance instruments with short-term debt that is intended for short-term (12-month) financing.[282]

[279] Exhibit 72 at 14-14.

[280] Exhibit 235 at 5 to 7.

[281] Exhibit 235 at 7.

[282] Exhibit 26 at 14-14.

13.1.2.2.3. Discussion

The settling parties agree to a $26 million reduction in revenue requirement pertaining to GHG assets and for PG&E to recover the carrying costs for GHG compliance instruments in the ERRA proceeding or Annual Gas True up advice letters. Because the Commission reviews the reasonableness of PG&E's procurement of GHG compliance instruments in the ERRA, it is reasonable to adopt the settlement's recommendation for PG&E to remove the carrying costs for the GHG compliance instruments from Rate Base and allow PG&E to recover them through the ERRA. We therefore adopt the settlement's $26 million reduction in revenue requirement for GHG assets.

13.1.3. Customer Advances

PG&E requires new customers to provide refundable customer advances when PG&E connects the new customer to utility service. The balance of customer advances reduces the Rate Base. Parties did not oppose PG&E's forecast of customer advances.

The settlement adopts PG&E's unopposed forecast of $77.259 million.[283] We reviewed PG&E's forecast, determined it to be reasonable, and adopt it.

13.1.4. Customer Deposits

PG&E requires customers who do not have good financial credit or who have been disconnected for non-payment to provide a deposit.

Cal Advocates proposed that customer deposits be authorized as a source of long-term debt financing for PG&E, which would reduce PG&E's revenue requirement. Cal Advocates argued that this approach is consistent with the

[283] Exhibit 80, Appendix A at 18.

precedents established in D.14-08-032 (PG&E's 2014 GRC) and D.17-05-013 (PG&E's 2017 GRC).[284]

PG&E proposed that the Commission address the ratemaking treatment of customer deposits as a funding source in its 2020 Cost of Capital proceeding.[285] PG&E explained that D.14-08-032 (PG&E's 2014 GRC) directed PG&E to provide "a comprehensive review of the treatment of customer deposits in (its) next cost of capital proceeding."[286] PG&E has done so in A.19-04-014 (PG&E 2020 Cost of Capital).[287]

The settling parties agree that the ratemaking treatment of PG&E's customer deposits should be consistent with the treatment granted in D.19-12-056 (PG&E's 2020 Cost of Capital). D.19-12-056 sufficiently addressed the ratemaking treatment for customer deposits.[288] There is no compelling reason in the record to deviate from the treatment granted in D.19-12-056. Therefore, we find it reasonable and adopt the settling parties' proposal to continue the ratemaking treatment granted in D.19-12-056 for customer deposits.

However, D.20-06-003 (Disconnections OIR decision), effective June 11, 2020, prohibits PG&E from collecting customer deposits.[289] As a result, PG&E will not be able to collect customer deposits midway into this GRC cycle. We direct PG&E to file a Tier 2 Advice Letter within 90 days of the effective date of this decision to make any necessary corrections to the ratebase and revenue

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[284] Exhibit 235 at 10.

[285] Exhibit 80 at 13-2.

[286] D.14-08-032 at 629.

[287] D.19-12-056 at 48.

[288] D.19-12-056, Ordering Paragraph 6 at 55.

[289] D.20-06-003, Ordering Paragraph 8 and 9.

requirement to reflect the removal of customer deposits ordered in the Disconnections OIR decision.

13.1.5. Depreciation Reserve and Depreciation Expenses

Depreciation Reserve is the total amount of depreciation (in terms of dollars) that has accumulated from the assets that are in Utility Plant. In other words, the Depreciation Reserve is the total amount of annual depreciation expenses that have been deducted from the assets that are in plant.

Depreciation expenses allow the utility to recover the capital costs of fixed assets, less net salvage value, plus removal costs, in equal installments (on a "straight line" basis) over the estimated remaining service life of the assets. According to the Commission's Standard Practice U-4 (SP U-4), depreciation expenses are determined annually based on the following formula:[290]

$$\text{Annual Depreciation Expense} = \frac{\text{(Plant Balance - Net Salvage Value + Removal Costs - Depreciation Reserve)}}{\text{Estimated Remaining Service Life}}$$

Net salvage value, removal costs, and estimated service lives are factors that determine the utility's annual depreciation expenses (see formula above) and are often referred to as depreciation parameters.

After the utility recovers a depreciation expense, the depreciation reserve is credited, or increased, by the amount of the depreciation expense, resulting in an accumulated depreciation reserve balance. The depreciation reserve is included in the rate base calculation as a reduction to the rate base. As depreciation expenses are recognized, and the depreciation reserve is increased

[290] Commission Standard Practice U-4 (SP U-4), "Determination of Straight-Line Remaining Life Depreciation Accruals" was first issued in 1952 and last revised in 1961.

by the amount of depreciation expenses, the utility's rate base is also reduced by the same amount of accumulated depreciation expenses.

Because utility assets generally have service lives that span several generations of ratepayers, a systematic and fair apportionment of the asset costs, through an appropriate amount of depreciation expense every year, is important for maintaining the equity of intergenerational ratepayers. A systematic and fair apportionment of the utility asset costs allows each generation of ratepayers to pay their fair share of depreciation expenses for the use of the assets, so that one generation of ratepayers does not have to bear substantively more of the asset costs than others.

Depreciation expenses also include decommissioning accrual expenses. We are not addressing the issues with PG&E's decommissioning accrual expenses in this section. We address them separately in the Energy Supply section.

13.1.5.1. Settlement Agreement

During evidentiary hearings, PG&E, Cal Advocates, and TURN reached a stipulation to retain the depreciation rates and depreciation parameters from D.17-05-013 (PG&E's 2017 GRC Decision) for this GRC.[291] The stipulation reduces PG&E's requested depreciation expenses by $38 million, from $2,831 million to $2,796 million.[292] The stipulation also allows parties to make further adjustments if there is a settlement.

The settlement agreement further adjusts several of the depreciation parameters the parties agreed upon in the initial stipulation.[293] These further

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[291] Exhibit 283

[292] Motion for Settlement at 42.

[293] Settlement Agreement, Appendix D.

depreciation parameters adjustments result in a $150 million revenue requirement reduction for PG&E's depreciation expenses, as compared to a reduction of $38 million of forecasted depreciation expenses set forth in the initial stipulation.

13.1.5.2. Positions of the Parties

PG&E initially forecasted $2.831 billion for depreciation expenses in 2020, which consists of $531 million for gas distribution-related depreciation expenses, $1.610 billion for electric distribution-related depreciation expenses, and $690 million for electric generation-related depreciation expenses.[294] PG&E's 2020 depreciation expense forecast is an increase of $508 million, or 22 percent, to the 2017 recorded depreciation expense.[295] PG&E hired Gannett Fleming, an outside vendor, to conduct a depreciation study. Gannett Fleming recommended depreciation parameters, such as net salvage values, removal costs, and estimated service lives, for each class of PG&E's assets in the depreciation study. This study forms the basis of PG&E's original forecast.

Cal Advocates proposed adjusting several of PG&E's depreciation parameters, which reduces PG&E's 2020 forecasted depreciation expense by $158 million.[296,297] (The $158 million reduction includes a $8.5 million reduction

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[294] Exhibit 80 at 10-6. Table 10-3.

[295] The breakdown of the depreciation expense increase from 2017 recorded to 2020 forecast is $66.8 million for gas distribution, $250.6 million for electric distribution and $190.5 million for electric generation.

[296] Cal Advocates recommended a 2020 depreciation expense forecast of $2.672 billion, which consists of $1.521 million for electric distribution-related expenses ($89 million less than PG&E's forecast), $502 million for gas distribution-related expenses ($29 million less than PG&E's forecast), and $649 million for electric generation-related expenses ($41 million less than PG&E's forecast). *See* Exhibit 163 at 3.

[297] PG&E stated that Cal Advocates' recommended depreciation rate changes result in a $76.6 million reduction in depreciation expense to PG&E's forecast when the recommended

Footnote continued on next page.

to PG&E's hydroelectric decommissioning accrual expense. PG&E's hydroelectric decommissioning accrual expense is discussed in the Energy Supply chapter. Cal Advocates recommended the following adjustments: 1) depreciation rate reductions for PG&E's gas software account and electric overhead services account, 2) net salvage rate changes for PG&E's electric station equipment account, electric poles account, electric underground conductors and devices account, gas mains account, and gas services account, and 3) a different survivor curve for PG&E's electric overhead services account.

TURN also recommended several changes to PG&E's depreciation parameters. TURN's proposed adjustments to PG&E's parameters would reduce PG&E's forecasted depreciation expense by $406.9 million.[298,299] First, TURN proposed lengthening the average service lives of the following accounts: computer software; electric transmission station equipment; electric transmission poles and fixtures; electric distribution station equipment; electric distribution poles, towers, and fixtures; electric distribution overhead conductors and devices; electric distribution underground conduit; electric distribution underground conductors and devices; electric distribution line transformers; electric distribution overhead services; electric distribution underground services; gas distribution measuring and regulating equipment; gas distribution

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depreciation rate changes were applied to PG&E's 2020 forecasted plant balance. *See* Exhibit 72 at 10-5.

298 TURN's proposed $406.9 million of depreciation expense reduction consists of a $195 million reduction to the electric accounts, $85.8 million reduction to the gas accounts, and $126.1 million to the common plant accounts. These numbers result from applying TURN's recommended depreciation parameters to PG&E's plant balances as of December 31, 2017. *See* Exhibit 241 at 3.

299 PG&E stated that TURN's recommended depreciation rate changes result in a $434.0 million reduction in depreciation expense to PG&E's forecast, when the recommended depreciation rate changes were applied to PG&E's 2020 forecasted plant balance. *See* Exhibit 72 at 10-5.

services; and gas distribution meters. TURN argued that the service lives PG&E proposed for these accounts are too short because the depreciation study conducted by Gannet Fleming uses "statistically aged" data, or data that statistically determine the assets' installation years using Iowa curves, when real historical data is not available. TURN asserted that using "statistically aged" data consistently yields shorter survivor curves, or average service lives, than using PG&E's historical data. Therefore, according to TURN, the estimated service lives for these accounts forecasted by PG&E are unreasonably short, which resulted in unreasonably high depreciation expenses.

Next, TURN proposed changes to the net salvage values of the following accounts: electric distribution overhead conductors and devices; gas mains; and gas services. TURN argued that PG&E failed to use recent net salvage data in the depreciation study, which resulted in PG&E's forecasted net salvage values being less than would be suggested by recent recorded data.

PG&E argued that its depreciation study is balanced, using several factors such as historical data, information provided by PG&E's subject matter experts, the incorporation of judgment, and the concept of gradualism.[300,301] PG&E argued that the other parties' proposals to lower depreciation expenses will

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300 D.14-08-32 (PG&E's 2014 GRC Decision) adopted the concept of "gradualism." "Gradualism" is a principle by which "there is a recognized need to revise estimated parameters, but where the change is allowed to occur incrementally over time rather than all at once. Applying gradualism thus limits the approved increase that would otherwise be warranted, all else being equal, and mitigates the short-term impact of large changes in depreciation parameters." In other words, "gradualism" limits any change to depreciation parameters to small, gradual modifications, so that significant short-term impacts to depreciation expenses can be avoided. *See* D.14-08-032 at 596 to 602.

301 Exhibit 72 at 11-10.

increase depreciation costs in the future and result in a higher total cost to customers, as plant balances remain longer in rate base.[302]

13.1.5.3. Discussion

Because the initial stipulation allows the parties to make further adjustments in light of a broader settlement, the settlement agreement adopts many but not all of the parameters set forth in the initial stipulation. These parameters, which are based on the depreciation parameters that the Commission authorized in PG&E's last GRC (2017 GRC), are reasonable. Since the last GRC, there have been no major factors changing the appropriateness of using these parameters to set depreciation expenses. Adopting these depreciation parameters for calculating depreciation expenses will continue to provide intergenerational equity for ratepayers. These parameters (the average service lives, survivor curves, net salvage percentages) are therefore reasonable in light of the whole record, and we adopt them.

The settlement agreement modifies some of the depreciation parameters adopted by the stipulation that were initially contested by the parties. These modifications represent a compromise of the parties' initial litigated positions and result in a $150 million revenue requirement reduction related to depreciation expenses, as compared to the $38 million reduction of depreciation expenses proposed in the initial stipulation. We discuss the reasonableness of these modifications below.

These modifications include changing the proposed service life forecasts and survivor curves for some of the asset classes. The settlement's modified service life estimates and survivor curves are similar to, or slightly higher than,

[302] Exhibit 72 at 11-6.

estimates authorized in the 2017 GRC. For those that differed from what was authorized in the 2017 GRC, the differences are insignificant. The proposed service life estimates increase the 2017 GRC authorized estimates modestly, most by only two to three years. Because these service life forecasts and survivor curves are similar to those in the 2017 GRC, the depreciation expenses adopted by the settlement promote the concept of intergenerational fairness in the distribution of depreciation expenses. Thus, we find the modified service life forecasts and survivor curves included in the settlement to be reasonable and adopt them.

The settlement also modifies the net salvage percentages for some of the asset classes that were initially contested by the parties. The net salvage percentages proposed by the settling parties represent a compromise of the parties' initially disputed positions (as shown in the table below) and are supported by the record as within the range of reasonable outcomes. For these reasons, we find it reasonable to adopt the net salvage percentage forecasts proposed in the settlement.

Table[303,304]

FERC Account	Account Description	Currently Authorized	PG&E Proposed	Cal Advocates' Initial Position	TURN's Initial Position	Settlement
Electric Distribution						
365	Overhead Conductors	($125)	($100)	($100)	($86)	($90)

303 Exhibit 72 at 10-7.

304 Settlement Agreement of the 2020 General Rate Case of Pacific Gas and Electric Company, Appendix D, Average Service Lives/Mortality Curves, Net Salvage Percentages, and Accrual Rates.

	and Devices					
Gas Distribution						
360	Services	($124)	($100)	($90)	($44)	($81)

The modifications proposed by the settlement agreement reduce PG&E's proposed revenue requirement by $150 million. In light of the whole record, we determine that the depreciation reserve and depreciation expenses proposed by the settlement agreement support the concept of intergenerational equity. Thus, they are reasonable and are adopted.

13.2. Taxes and Deferred Taxes

This section discusses PG&E's forecasted tax expenses and the method PG&E uses to calculate these tax expenses. PG&E's forecasted tax expenses are comprised of corporate income taxes, property taxes, payroll taxes, and taxes other than income and property that PG&E will incur from providing gas and electric services.

In this section, we will also address PG&E's forecasted deferred income taxes. Deferred income tax balances result from the timing differences between book depreciation used for ratemaking purposes and tax depreciation used for tax purposes. Accumulated Deferred Income Taxes (ADIT), which includes tax deductions resulting from bonus depreciation, deferred tax assets, deferred investment tax credits, and accumulated deferred tax liabilities, is a reduction to rate base.

PG&E's tax expenses and deferred taxes are calculated by the RO model using the capital expenditures and capital additions we approve in Rate Base, as well as the current tax rates and deductions governed by the current tax laws. Since the amount of tax expenses and deferred taxes fluctuate based on the capital expenditures and additions we approve, we determine the reasonableness of PG&E's tax expenses by whether PG&E's method for calculating tax expenses are reasonable.

13.2.1. Settlement Agreement

The settling parties agree to continue but modify the Tax Memorandum Account (TMA) so that it only records any net revenue changes due to mandatory and elective tax law, tax accounting changes, tax procedural changes, or tax policy changes.

The settling parties also agree to address the excess accumulated deferred income taxes (excess ADIT) that were created by the passage of the Tax Cuts and Jobs Act of 2017 (2017 Tax Act) in an advice letter filing, such as the Annual Electric True-Up.

13.2.2. Parties' Positions

The parties did not oppose any of PG&E's method for calculating tax expenses.

However, the parties contested PG&E's proposal to close the TMA. PG&E initially argued that the TMA should be closed because it is inconsistent with the policies set in D.84-05-036 (Order Instituting Investigation 24 decision), which acknowledged the difficulty in isolating individual factors that cause differences in the estimated and recorded income taxes.[305] PG&E also argued that, because several accounting terms used in the TMA are not clearly defined, there could be misinterpretations about the operation and calculation of the TMA balances. Cal Advocates recommended that the TMA remain open to mitigate any impacts

[305] Exhibit 80 at 12-6.

from changes in tax law, tax guidance, or tax accounting method changes, and to allow for transparency of the utility's incurred and forecasted tax expense.

13.2.3. Discussion

PG&E's forecasted tax expenses and proposed method of calculating tax expenses are uncontested. After reviewing PG&E's testimony, we determine that PG&E's forecasted tax expenses and method for calculating tax expenses to be reasonable and therefore adopt them.

The settling parties propose that PG&E file an advice letter, such as the Annual Electric True-up filing, to correctly reflect the return of excess ADIT created by the passage of the 2017 Tax Act, consistent with the methodology ordered by D.19-08-023 (Decision granting PG&E's Petition for Modification of the 2017 GRC to reflect the effects of the 2017 Tax Act). The excess ADIT balance was created when the 2017 Tax Act reduced PG&E's federal corporate income tax rate from 35 percent to 21 percent. As a result, a portion of existing ADIT (excess ADIT) is no longer needed to pay for future taxes. Based on our interpretation of the settlement, these tax corrections to return excess ADIT to ratepayers, which will lower PG&E's revenue requirement, are not currently included in PG&E's revenue requirement calculations.

We agree with the settlement that it is reasonable for PG&E to file an advice letter to correct the excess ADIT calculations. Procedurally, rather than filing these corrections in the Annual Electric True-up advice letter, we direct PG&E to file these corrections through a separate Tier 2 advice letter within thirty days of the date of this decision. In the advice letter, PG&E shall show the incremental revenue requirement reductions for Test Year 2020 and each of the attrition years, and shall also include the proposed amortization period for the reductions.

Besides the excess ADIT corrections, the settling parties also reached an agreement on the TMA. The settlement agreement proposes to retain the TMA but modify it to be consistent with the changes ordered in D.19-09-051 (Sempra 2018 GRC). Specifically, the settlement proposes to modify the TMA so that it does not track any net revenue changes due to differences between actual and forecasted tax expenses other than those due to mandatory tax law changes, tax accounting changes, tax procedural changes, or tax policy changes, and elective tax law changes, tax accounting changes, tax procedural changes, or tax policy changes.

The changes to the TMA proposed by the settlement strike a reasonable balance between the parties' positions. The proposed modifications to the TMA remove PG&E's burden of recording all differences in estimated and recorded income taxes. This is reasonable because there are inherently many factors that cause these differences, and these factors are also difficult to isolate and identify. The settlement also addresses Cal Advocates' concerns for a transparent process to track any changes to income taxes due to mandatory or elective tax law, tax guidance, tax policy, or tax accounting changes. Therefore, the modifications to the TMA proposed by the settlement are reasonable and are adopted.

13.3. Other Operating Revenues (OOR)

OORs are revenues PG&E receives that are not directly generated from rates, but are related to its generation, distribution, or sale of electric energy or natural gas activities.[306] These revenues come from items such as rent from electric and gas properties, field collection, reconnection fees and return-to-maker check charges, recreational facilities and timber sale receipts,

[306] Exhibit 80 at 15-1.

sales of water for power, transmission wheeling service fees, revenues reimbursing PG&E for work performed for other entities, and other miscellaneous service revenues.[307] The OORs reduce PG&E's revenue requirement forecast.

The electric OORs consist of revenues from the following accounts:

1. Electric Forfeited Discounts – This account includes fees from customers for failure to pay their electric bills, such as forfeited deposits, reconnection fees, and field collection fees.
2. Electric Miscellaneous Service Revenues – This account includes revenues for miscellaneous services and charges received from customers for services such as relocating facilities, installing temporary facilities, disconnecting customers as a result of energy theft, and new connection administrative costs.
3. Sale of Water and Water for Power – This account includes revenue derived from the sale of water for power.
4. Rent from Electric Property – This account includes rents PG&E receives for leasing its land, buildings, or other properties devoted to electric operations. The account also includes payments from Qualifying Facilities for services and equipment PG&E provides.
5. Other Electric Revenues – This account includes revenues not included in other OOR accounts, such as tax gross-up on Contributions in Aid of Construction, reimbursed revenue, recreational facilities and timber sales, transmission wheeling service fees, and other miscellaneous items.

The gas OORs consist of revenues from the following accounts:

1. Gas Forfeited Discounts – This account includes fees charged to customers for failing to pay their gas bills, such as forfeited discounts, reconnection fees, and field collection fees.
2. Gas Miscellaneous Service Revenues – This account includes revenues for miscellaneous services and charges received from customers for services such as relocating facilities, installing temporary facilities, disconnecting

[307] *Ibid.*

customers as a result of energy theft, and new connection administrative costs.

3. Revenue from Transporting and Storage of Gas for Others – This account includes revenues generated from exchanging gas with other entities
4. Rent from Gas Properties – This account includes rents received from the lease of PG&E's land, buildings, and other property devoted to gas operations.
5. Other Gas Revenues - This account includes revenues not included in other OOR accounts, such as tax gross-up on Contributions in Aid of Construction, reimbursed revenue, and other miscellaneous items.

13.3.1. Settlement Agreement

The settlement agreement proposes adopting PG&E's forecast of OORs, which is $194.587 million.

13.3.2. Parties' Position

PG&E's 2020 forecast of OORs is $194.587 million.[308] PG&E derived these forecasts through an item-by-item forecast, or a bottoms-up forecast.

Cal Advocates originally recommended increasing PG&E's electric OORs to $172.8 million, which is $30.8 million more than PG&E's forecast. Specifically, Cal Advocates recommended adjustments to PG&E's forecast in Rent from Electric Property (FERC Account 454) and Other Electric Revenues (FERC Account 456). Cal Advocates' forecast for Rent from Electric Property was derived using a 5-year average of historical data. Cal Advocates' forecast for Other Electric Revenues was derived using a five-year linear trend.
Cal Advocates did not dispute PG&E's gas OORs of $32.6 million.

13.3.3. Discussion

After considering the parties' original positions, adopting PG&E's OORs forecast of $194.587 million, as proposed by the settlement agreement, is

[308] Motion of PG&E to Amend Settlement Agreement at 3.

reasonable in light of the whole record. For the two accounts that were originally contested by Cal Advocates, PG&E argued that its item-by-item forecasting delivers a more accurate forecast than does forecasting based on historical account totals, because PG&E's OORs vary significantly from year-to-year. Taking rental income as an example, PG&E receives rental income from one-time events, such as a $12 million one-time fee PG&E received from the Bay Area Rapid Transit system in 2018. Because of these large one-time revenues, PG&E argues that OORs vary significantly from year-to-year and cannot be accurately forecasted based on historical data. Instead, PG&E proposes using expected activities and events to forecast future revenue amounts.

The record demonstrates that PG&E's OORs revenues can be forecasted with reasonable certainty from expected future activities and events, and that one-time events can cause significant variation in PG&E's revenue streams. Thus, PG&E's item-by-item forecasting method, on which the settlement is based, is reasonable. We therefore adopt the settlement forecast of $159.593 million for PG&E's OORs.

13.4. Cost Allocation Adjustments

PG&E allocates the operational and capital costs it requests to recover in this GRC into three major utility functions: electric generation, electric distribution, and gas distribution. Based on the costs that the Commission approves PG&E to recover, PG&E derives a revenue requirement and a set of utility rates for each of these three major functions. Through the utility rates, PG&E customers pay for one or more of the services offered by PG&E (such as electric generation, electric distribution, and gas distribution services). Bundled electric customers pay for PG&E's electric generation and electric distribution services, while unbundled electric customers, like those who receive electric generation services from Community Choice Aggregators (CCAs), pay PG&E only for the electric distribution services.

In this decision, we will refer to the process by which PG&E allocates costs across its various functions as the "functionalization" of costs, or PG&E's cost allocation methodology.

PG&E did not specifically present its proposed cost functionalization methods in its direct testimony even though its requested revenue requirements for each utility function (electric generation, electric distribution, and gas distribution) are derived by allocating costs to these functions using its proposed functionalization methods. Parties, including the JCCAs, received information about PG&E's proposed cost functionalization methodologies through discovery requests and included them in their testimony, particularly on issues they contest. In rebuttal testimony, PG&E clarifies its proposed cost functionalization methods and provides support for these proposals.

PG&E proposes to allocate its costs differently for each set of program expenses. For costs associated with common plant,[309] which we will also refer to as Common Costs, PG&E proposes to allocate these costs across all its major functions because all of PG&E's major utility functions share usage of the same resource. For costs of programs that support only one of its functions (such as electric distribution services), PG&E proposes to allocate these program costs only to that specific utility function.

Among the parties, the JCCAs contested PG&E's cost functionalization methods the most, arguing that many of PG&E's proposed cost allocations are contrary to cost causation principles because they do not appropriately attribute

[309] PG&E refers to these plants as residual common plants. *See* Exhibit 80 at 9-6.

costs to bundled customers and unbundled customers.[310] The JCCAs further assert that Pub. Util. Code Section 366.2 forbids cost shifts between bundled and unbundled customers.[311] The JCCAs argue that, because bundled customers use more of the programs and services than do unbundled customers, PG&E should shift some or all of the costs of these programs from its distribution function (for which both the bundled and unbundled customers pay) to its generation function (for which bundled customers pay but unbundled customers do not pay).[312]

The JCCAs propose specific cost allocation adjustments to several PG&E programs (CWSP, Customer Care, Locate and Mark, etc.). TURN originally proposed that PG&E change its cost functionalization for CWSP aviation expenses. Cal Advocates also proposed that PG&E change its cost functionalization of the excess liability insurance expenses. TURN and Cal Advocates have settled these cost allocation issues with PG&E in the settlement. The settlement, however, does not address all of the cost allocation issues the JCCAs raise.

The Commission has a longstanding policy of allocating costs to customers based on the costs the utilities incur on behalf of those customers.[313] Consistent with previous decisions, we use this policy as a guiding principle in our review and resolution of the cost allocation issues.

In this section, we also address the JCCAs' request for PG&E to provide more detail and transparent information about its cost allocation methodologies

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310 JCCAs' Opening Comments at 18.

311 JCCAs' Opening Brief at 11.

312 JCCAs' Opening Comments at 17.

313 D.19-09-004 at 4.

in future GRC filings. The JCCAs make this request because they assert that PG&E failed to provide sufficient detail regarding its cost allocation methodologies in this GRC.[314]

13.4.1. Settlement Agreement

The settling parties agree to the following cost allocation methods:

1. Community Wildfire Safety Program (CWSP) – Support Programs: Costs are allocated as Common Costs.
2. CWSP – Enhanced Operational Practices, Aviation (Heavy-Lift Helicopters): Costs are allocated as Common Costs.
3. Various CWSP Emergency Preparedness and Response (EP&R): Costs are allocated as Common Costs.
4. Locate and Mark: Costs are allocated 33.3 percent to electric distribution and 66.7 percent to gas distribution.
5. Excess Liability Insurance: Costs are allocated as Common Costs.
6. Pricing Programs and Income Qualified Programs (MWC EZ – Manage Various Customer Care Processes): The rate programs that are only for electric customers are allocated 100 percent to ED.
7. Manage Service Inquiries (MWC EV – New Business Service Inquiry, MAT EVA – Service Inquiries): Costs are allocated 55 percent to ED and 45 percent to GD.

The settlement does not address some of the cost allocation adjustments the JCCAs propose, including those pertaining to Customer Care expenses, Integrated Grid Platform expenses, and CWSP resilience zone costs. The settling parties state that, "[c]ertain cost allocation issues remain unresolved."[315]

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[314] JCCAs' Opening Brief at 75 to 77.

[315] Joint Motion for the Settlement Agreement at 41.

13.4.2. Discussion

We first address the specific cost allocation issues addressed in the settlement. Then, we address the cost allocation issues the settlement does not address.

13.4.3. Cost Allocation Issues addressed in the Settlement

13.4.3.1. Cost Allocation of CWSP Cost addressed in the Settlement

PG&E initially proposed to allocate all costs of CWSP support programs to electric distribution. PG&E updated its position in rebuttal to allocate these costs as common. PG&E initially proposed to allocate all capital CWSP emergency preparedness and response costs to electric distribution. PG&E updated its position in rebuttal to agree with the JCCA's proposal to allocate these costs, along with related expenses, as common. Thus, PG&E proposes that CWSP situation awareness program costs, CWSP program support costs, and costs of CWSP activities performed by its emergency, preparedness, and responses organization be treated as common costs.[316,317] PG&E states that because wildfires present a threat to all PG&E infrastructure, such as substations, gas compressor stations, and powerhouses, and that wildfire mitigation benefits all of the utility functions (electric distribution, electric generation, and gas distribution), it is appropriate to treat wildfire mitigation costs as common costs.[318]

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[316] Exhibit 16 at 1-5.

[317] Exhibit 16 at 3-7.

[318] Exhibit 215 at 21 to 22.

The settling parties agree that these specific CWSP costs should be treated as common costs. Even though the JCCAs are not among the settling parties, the JCCAs recommend treating these CWSP costs as common costs.[319]

Because PG&E incurs CWSP costs (situation awareness program costs, program support costs, and costs of CWSP activities performed by its emergency, preparedness, and responses organization) to support wildfire mitigation efforts that benefit all of the utility functions, the settlement's treatment of these CWSP costs as common costs is reasonable and is therefore adopted.

13.4.3.2. Cost Allocation of CWSP Aviation (Heavy-Lift Helicopters) Expenses addressed in the Settlement

For the costs of the heavy lift-helicopters that PG&E proposes to purchase as part of its CWSP, PG&E proposes to treat the costs of the helicopters as common costs, allocating the costs across all its functions (electric distribution, electric generation, and gas distribution).[320]

Before the settlement, TURN opposed PG&E's treatment of these costs as common costs and proposed that PG&E allocate 67 percent of these costs to electric transmission and 33 percent of these costs to electric distribution. TURN presented data showing that a large majority, or 91 percent, of PG&E's helicopter usage is for activities related to electric transmission, while only a very small percentage, or nine percent, is for non-electric transmission activities.[321] In rebuttal, PG&E explained that it plans to use these helicopters for firefighting,

[319] Exhibit 215 at 22.

[320] Exhibit 72 at 7-3 to 7-5.

[321] Exhibit 276 at 57 to 60.

restoring service during emergencies, internal construction, and repair and maintenance. As part of its wildfire mitigation plan, PG&E stated that these helicopters will benefit all PG&E assets and customers and should therefore be treated as a common cost. PG&E also argued that its future planned usage of these new helicopters is different than PG&E's historical usage of helicopters.[322]

In the settlement, the settling parties, which include TURN and PG&E, agree to treat the expenses for the helicopters as common costs.

In comments to the settlement, the JCCAs state the settlement's proposed treatment of these helicopter costs as common costs splits these costs 55 percent and 44 percent between gas and electric customers, based on the number of gas and electric customers.[323] The JCCAs state that they support PG&E's originally proposed cost allocation method, in which expenses would be charged to the line-of-business units based on usage and capital expenditures would be allocated based on labor ratios.[324]

In response, the settling parties state that the settlement's treatment of the helicopter costs as common costs is the treatment that PG&E proposed originally. The settling parties clarify that the chargebacks for expenses and the allocation of capital based on labor ratios are part of PG&E's common cost allocation methodology.[325]

PG&E will use the helicopters for firefighting, restoring service during emergencies, internal construction, and repair and maintenance. PG&E incurs

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322 Exhibit 72 at 7-4 to 7-5.

323 Comments of the JCCA on the Joint Motion for Approval of Settlement Agreement at 17 to 19.

324 *Ibid*.

325 Joint Reply Comments of PG&E, Cal Advocates, TURN, CforAT, NDC, SBUA, CCUE, California City County Street Light Association, and SED at 36 to 37.

these costs to benefit all PG&E assets and functions. Therefore, the settling parties' proposed treatment of the helicopter costs as common costs is reasonable, and we adopt it. Because the cost allocation methods PG&E proposed for common costs were initially unclear, we direct PG&E to clarify and provide more details in its next GRC on the cost allocation methods it proposes, including how it allocates costs it considers as common costs. More details on the additional requirements PG&E shall submit in its next GRC are discussed in the "Future Presentation of PG&E's Cost Allocation Proposals" section below.

13.4.3.3. Locate and Mark

PG&E originally proposed to functionalize costs for Locate and Mark activities by the allocation percentages designated in their associated FERC accounts.[326] Overall, PG&E's method of functionalizing Locate and Mark activities allocates 57 percent of the Locate and Mark costs to electric distribution and 43 percent of the costs to gas distribution.[327]

The JCCAs oppose PG&E's original functionalization of Locate and Mark costs, arguing that it is unreasonable to allocate 57 percent of the costs to electric distribution when, according to PG&E's testimony on Gas Distribution activities,[328] the majority of Locate and Mark activities are related to the gas distribution function. The JCCAs recommend that Locate and Mark costs be allocated 33.3 percent to electric distribution and 67.7 percent to gas distribution to reflect the substantial benefit of these activities to the gas distribution function.

In rebuttal, PG&E agrees with the JCCAs' proposed allocation, acknowledging that the cost allocation of Locate and Mark activities should

326 Exhibit 216, Attachment JAM-2 at 44 to 45.

327 Exhibit 15 at 6-7 to 6-8.

328 Exhibit 10 at 6-6 to 6-16.

reflect the fact that most Locate and Mark activities are associated with its gas distribution assets.[329]

The settling parties agree to allocate Locate and Mark costs 33.3 percent to electric distribution and 66.7 percent to gas distribution, as proposed by the JCCAs and agreed to in rebuttal by PG&E. The settling parties' proposed allocation is reasonable, given that a majority of Locate and Mark activities pertain to the gas distribution function, while the rest of the Locate and Mark activities support the electric distribution function. Thus, we adopt the settlement's cost allocation of Locate and Mark activities.

13.4.3.4. Excess Liability Insurance

PG&E proposes to functionalize excess liability insurance as a common cost expense, similar to other A&G expenses. Specifically, PG&E proposes to allocate the excess liability insurance costs according to the 2017 recorded operation and maintenance labor factors.[330] Under this proposal, approximately 44 percent of the excess liability insurance costs are allocated to electric distribution and electric transmission customers, while the remaining 56 percent of the costs are allocated to gas distribution, gas transmission, and electric generation customers.[331]

Cal Advocates originally opposed this allocation. Arguing that the increase in excess liability insurance costs is a result of increased wildfire risk that is related to PG&E's electric distribution and transmission assets, Cal Advocates recommended that the incremental costs of the excess liability

[329] Exhibit 15 at 6-7 to 6-8.

[330] Exhibit 72 at 7-2.

[331] *Ibid.*; Exhibit 80 at 7-3.

insurance, which is approximately $300 million, be allocated entirely to the electric distribution and electric transmission functions.[332]

The JCCAs support PG&E's proposed allocation.[333] PG&E and the JCCAs argue that PG&E faces potential liabilities across all its functions and the excess liability insurance protects PG&E against third-party claims for all its lines of business.[334] In rebuttal, PG&E explains that it purchased the liability insurance as an enterprise single tower coverage policy that is not specific to any utility function but is general in nature, and should therefore be treated as a common cost expense.[335]

The settling parties agree to treat the excess liability insurance costs as a common cost expense, as PG&E proposed, which would allocate the costs 37 percent to electric distribution, 22 percent to gas distribution, 24 percent to electric generation, 6 percent to electric transmission, and 11 percent to gas transmission. Since PG&E incurs the excess liability insurance to provide coverage for all of PG&E's lines of business, the settling parties' proposed cost allocation of the excess liability insurance is reasonable, and we adopt it.

We note Cal Advocates' initial concerns that the extraordinary increase in excess liability insurance costs, approximately $300 million, or 245 percent, was primarily a result of increased wildfire risks.[336] PG&E also plans to increase coverage of its wildfire perils within its general liability coverage.[337] Since

[332] Exhibit 174 at 15.

[333] Exhibit 215 at 39 to 42.

[334] Exhibit 72 at 7-2 to 7-3; Exhibit 159 at 3-32.

[335] Exhibit 159 at 3-32.

[336] Exhibit 157 at 3-14.

[337] Exhibit 157 at 3-23.

wildfire risks are primarily associated with PG&E's electric distribution and electric transmission assets, we direct PG&E to examine in its next GRC whether functionalizing its excess liability insurance and general liability insurance coverage as common costs is still appropriate. Similar to the requirements described in the "Future Presentation of PG&E's Cost Allocation Proposals" section below, we direct PG&E to provide a detailed explanation and reasoning to justify the cost allocation it proposes for the excess liability insurance costs in its next GRC.

13.4.3.5. Pricing Programs and Income Qualified Programs

The Pricing Products and Income Qualified Programs department is part of PG&E's Customer Care operations. For rate programs in this department that pertain only to electric customers, the settling parties propose to allocate 100 percent of these program costs to the electric distribution function. PG&E proposes to functionalize costs of its Customer Care operations between the electric distribution and gas distribution functions based on the number of the utility's gas and electric service agreements. As discussed in the "Cost Allocation of Customer Care Expenses" section below, we adopt PG&E's proposal to functionalize Customer Care expenses between the electric distribution and gas distribution functions. Since certain rate programs in the Customer Care (Pricing Programs and Income Qualified Program) department only pertain to electric customers, the settling parties' proposal to functionalize 100 percent of these costs to electric distribution is reasonable, because it allocates costs to the set of customers on whose behalf PG&E incurs the costs of these programs. We therefore adopt the settling parties' proposal.

13.4.3.6. Cost Allocation of MWC EV and MAT EVA (Manage Service Inquiries)

MWC EV (New Business Service Inquiry): includes the costs of work associated with processing applications of new gas and electric customers and work associated with helping existing customers add load to or rearrange their services.[338] MAT EVA (Service Inquiries) includes costs that support new gas and electric services.[339]

PG&E initially proposed to allocate 100 percent of the costs in MWC EV and MAT EVA to electric distribution, as that is how PG&E had historically functionalized these costs.[340] During discovery, PG&E revised the functionalization of these costs and proposed to allocate these costs 55 percent to electric distribution and 45 percent to gas distribution functions, based on the number of electric and gas customers, because these costs support work for both gas and electric services.[341]

The JCCAs propose that the costs in MWC EV be allocated using its Adjusted Common Customer Care Cost Allocator. The Adjusted Common Customer Cost Allocator is an allocation factor that the JCCAs developed to apply to PG&E's Customer Care expenses. This allocation factor splits costs 13.21 percent to electric generation, 42.84 percent to electric distribution, and 43.95 percent to gas distribution.[342] (We further discuss the JCCAs' Adjusted Common Customer Care Cost Allocator below, in the section "Cost Allocation of

[338] Exhibit 20 at 16-5.

[339] Exhibit 215, Attachment JAM-2 at 27-28.

[340] Exhibit 215, Attachment JAM-2 at 27-28.

[341] Exhibit 215, Attachment JAM-2 at 27-28; Exhibit 20 at 16-5.

[342] Exhibit 215 at 23 (Table 7).

Customer Care Expenses.") The JCCAs argue that MWC EV costs are related to customer service and deserve the same treatment the JCCAs propose for Customer Care expenses. Thus, according to the JCCAs, using its Adjusted Common Customer Care Cost Allocator better allocates costs based on the actual level of customer service used by bundled and unbundled customers.[343] PG&E argues against allocating MWC EV costs to electric generation, stating that the work does not apply to electric generation functions.[344]

The settling parties agree to functionalize the MWC EV and MAT EVA costs by allocating 55 percent of the costs to electric distribution and 45 percent of the costs to gas distribution.

Because the MWC EV and MAT EVA costs support electric and gas distribution services, the settling parties' proposed cost allocation method of splitting the costs based on the number of electric and gas service agreements, which results in allocating 55 percent of the costs to electric distribution customers and 45 percent of the costs to gas distribution customers, is reasonable, and we adopt it.

13.4.4. Cost Allocation Issues not addressed in the Settlement

We now resolve additional cost allocation issues not addressed in the settlement. The cost allocations issues that remain contested were raised by the JCCAs. We address these issues by first summarizing JCCA's proposals and then summarizing PG&E's responses.

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[343] Exhibit 215 at 40-41.

[344] Exhibit 20 at 16-5.

13.4.4.1. Cost Allocation of CWSP Costs Not Addressed in the Settlement

This section addresses cost allocation issues pertaining to CWSP costs that are not addressed in the settlement. For these CWSP costs, the JCCAs propose that PG&E functionalize some of these costs as electric distribution and electric transmission costs and the rest of these costs as common costs expenses. Specifically, the JCCAs propose to (1) allocate System Hardening costs and Enhanced Vegetation Management costs to electric distribution and electric transmission and (2) treat all other CWSP costs as common cost expenses.[345]

In rebuttal, PG&E opposes the JCCAs' proposed allocation of CWSP costs. Specifically, PG&E argues that CWSP programs that directly support electric distribution assets should be allocated only to electric distribution. These CWSP programs include System Hardening and Enhanced Vegetation Management (which the JCCAs propose to allocate to electric distribution and transmission), as well as Enhanced Operational Practices (Reclose Blocking costs and SCADA programming to support Reclose Blocking), and Automation and Protection Enhanced Operation Practices (fuse savers, granular sectionalizing, and Resilience Zones) (which the JCCAs propose to treat as common costs).[346]

In response, the JCCAs state that they do not oppose PG&E's proposal of allocating the System Hardening and Enhanced Vegetation Management costs 100 percent to electric distribution; however, they oppose this treatment for the Resilience Zone costs.[347] The JCCAs propose that the Resilience Zones costs, including the costs of the related interconnection facilities, be allocated solely to

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[345] Exhibit 215 at 21 to 22.

[346] Exhibit 20 at 1-5 to 1-6.

[347] Opening Brief of the Joint Community Choice Aggregators at 23 to 24.

electric generation, because PG&E is the sole entity installing or contracting generation that only PG&E will procure in the Resilience Zones.[348] If the Resilience Zones were modified according to the JCCAs' policy recommendations (allowing CCA-procured generation to be built in locations that are determined with input from the CCAs and which include permanent, clean onsite generation and storage),[349] then, according to the JCCAs, the costs of the Resilience Zones could be more widely socialized across distribution rates or Public Purpose Program rates.[350]

Arguing that the Resilience Zones equally benefit all distribution customers, PG&E asserts that the costs of Resilience Zones are more appropriately allocated 100 percent to electric distribution.[351] PG&E explains that the Resilience Zones provide temporary power to customers that would otherwise experience outages due to a PSPS event. PG&E argues that all distribution customers, both CCA and bundled customers, are indiscriminately affected by PSPS events and benefit equally from temporary service provided by the Resilience Zones during a PSPS outage.

Furthermore, PG&E clarifies that the Resilience Zones costs it requests to recover in this GRC are for the interconnection facilities that enable the distribution infrastructure in the Resilience Zones to connect to generation resources. PG&E states that it is not seeking to own the generation or specify the generation resources that will be used in the Resilience Zones. PG&E further

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348 Opening Brief of the Joint Community Choice Aggregators at 23 to 26.

349 *See* Chapter 18, Issues Outside the Settlement.

350 JCCA Opening Brief at 26.

351 PG&E's Reply Brief on Disputed Issues at 11 to 12.

explains that it is building Resilience Zones to accommodate generic generation resources, which are not specific to generation that only PG&E will procure.[352]

As discussed in the above section (Cost Allocation of CWSP Costs addressed in the Settlement), because PG&E incurs costs for CWSP that supports wildfire mitigation efforts that benefit all of the utility functions, it is reasonable to functionalize CWSP costs as common costs. For CWSP costs that directly support electric distribution assets, it is reasonable and appropriate to functionalize these CWSP costs 100 percent to electric distribution. These CWSP costs include the costs of the CWSP's Resilience Zones program.

The Resilience Zones program directly supports PG&E's electric distribution infrastructure and benefits all distribution customers. Furthermore, in this proceeding, PG&E is only requesting to recover the costs of building the interconnection facilities that enable the Resilience Zones to interconnect with generic generation resources. PG&E is not proposing to interconnect the Resilience Zones with any specific generation resource.

The Resilience Zones benefit all distribution customers by providing temporary power to customers affected by a PSPS event, regardless of whether the customer is bundled or unbundled. Similar to how PSPS events affect bundled and unbundled customers equally, the Resilience Zones also benefit bundled and unbundled customers equally. Thus, it would be unfair to shift all the costs of the Resilience Zones to electric generation, to be borne only by bundled customers.

For these reasons, it is reasonable, and we adopt, allocating the costs of the Resilience Zones 100 percent to electric distribution.

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[352] *Ibid.*

As we discussed in Chapter 18 of this decision, the JCCAs' policy recommendations concerning the Resilience Zones (allowing CCA-procured generation, be built in locations that are determined with input from the CCAs and include permanent, clean onsite generation and storage) are out of the scope of this proceeding.

13.4.4.2. Cost Allocation of Integrated Grid Platform Costs

The JCCAs request that PG&E provide real-time energy data that are generated through its grid modernization plan to load serving entities. In this GRC, PG&E requests recovery of an IGP as part of its grid modernization plan. The JCCAs argue that, if PG&E limits access to the data generated by the IGP, then some portion of the costs for this program should be allocated to the electric generation function, so unbundled customers do not have to pay for investments that do not bring them any associated benefits.[353]

In its rebuttal, PG&E argues that grid modernization improves cybersecurity, reliability, safety, and integration and management of distributed energy resources into the grid, benefitting both bundled and unbundled customers.[354] According to PG&E, because both bundled and unbundled customers will share equally in the benefits of the grid modernization programs, grid modernization costs, or IGP, should not be allocated to the generation function.[355]

By improving cybersecurity, reliability, safety, and integration of distributed energy resources, the current records show that grid modernization

[353] Exhibit 217 at 13.

[354] PG&E-18, Chapter 19 at 21.

[355] PG&E-18, Chapter 19 at 21.

directly supports PG&E's electric distribution infrastructure and benefits all distribution customers. The current record also shows that PG&E is incurring grid modernization costs on behalf of its distribution customers, and that both bundled and unbundled customers share the benefits of grid modernization. Based on the current record, we determine that grid modernization costs, or IGP costs, are appropriately allocated to electric distribution customers. However, we direct PG&E to examine more closely the appropriate cost allocation of the grid modernization costs for its next GRC. In its next GRC filing, PG&E shall include a detailed explanation and support to justify its proposed allocation of grid modernization costs.

As discussed in the chapter on Issues Outside the Settlement, we determine that the issue of access to the grid modernization data is more appropriately addressed in R.14-08-013 (Distributed Resource Planning OIR). After the Commission addresses the issue of data access, the parties may propose modifications to the current cost allocation of grid modernization costs.

13.4.4.3. Cost Allocation of Customer Care Expenses

13.4.4.3.1. Positions of the Parties

The JCCAs contest PG&E's cost allocation methodology for Customer Care expenses, which functionalizes 55 percent of the costs to electric distribution and 45 percent of the costs to gas distribution.[356] Arguing that PG&E's functionalization of Customer Care expenses gives unbundled customers an unfair share of the costs, the JCCAs propose that PG&E should allocate a portion of these costs to PG&E's electric generation function and decrease the share of costs allotted to electric distribution.

[356] PG&E's Reply Brief at 22.

The JCCAs assert that unbundled customers use PG&E's customer services less than bundled customers and should bear a lesser portion of the Customer Care costs. According to the JCCAs, customer usage data shows that bundled electric customers use PG&E's Contact Centers and Customer Services Office approximately twice as much as unbundled customers.[357] Arguing that usage drives customer service costs, the JCCAs propose allocating Customer Care costs based on the share of use between unbundled electric, bundled electric, and gas customers. The JCCAs argue that functionalizing costs by the customer's share of use is consistent with methods PG&E has used to functionalize other categories of costs.

Using data PG&E provided for activities in PG&E's Customer Engagement, Contact Centers, and Customer Service Offices departments, the JCCAs developed an Adjusted Common Customer Care Cost Allocator that apportions costs based on a weighted percentage share of use between bundled electric customers, unbundled electric customers, and gas customers. The Adjusted Common Customer Care Cost Allocator allocates 13.21 percent of customer service costs to electric generation, 42.84 percent of the costs to electric distribution, and 43.95 percent of the costs to gas distribution. The JCCAs apply their Adjusted Common Customer Care Cost Allocator to PG&E's Customer Engagement, Contact Centers, and Customer Service Offices expenses. Criticizing the lack of utilization data PG&E provided for the other Customer Care expenses, the JCCAs propose also to apply the Adjusted Common Customer Care Cost Allocator to other Customer Care expenses for which PG&E proposes to allocate costs between electric and gas distribution.

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[357] JCCAs' Opening Brief at 71 and 75.

PG&E allocates the Customer Care costs between its electric distribution and gas distribution functions, based on the number of its electrical and gas service agreements, resulting in an allocation of 55 percent of the costs to electric distribution and 45 percent of the costs to gas distribution.[358] PG&E argues that the JCCAs' proposal to allocate customer services costs to the electric generation function is inappropriate because the electric generation function does not directly provide any customer service.[359] Because customer services support its gas and electric distribution functions by providing the necessary support to all its gas and electric distribution customers, PG&E argues that it is appropriate to allocate Customer Care costs only to its electric distribution and gas distribution functions.

PG&E argues that its functionalization of Customer Care expenses is appropriate and equitable, because it aligns with the principle of cost causation that the Commission specified in D.14-12-024 (a decision pertaining to demand response programs), which stated that "costs should be borne by customers who cause the utility to incur the costs, not necessarily by those who benefit from the expense."[360] Citing to the same decision, in which the Commission concluded that it is reasonable to charge CCA customers for the costs of the demand response programs because the programs are equally available to CCA customers and bundled customers, PG&E argues that bundled and unbundled customers should similarly equally share the customer care costs since customer service expenses are equally available to bundled and unbundled customers.

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358 PG&E's Reply Brief at 22.

359 PG&E's Reply Brief at 25.

360 D.14-12-024 at 48.

In addition, PG&E argues that it incurs Customer Care costs on behalf of both bundled and unbundled electric customers, and that the level of customer services it provides to bundled and unbundled customers are the same. PG&E explains that bundled and unbundled customers have the same system reliability and service planning needs and that unbundled customers, like bundled customers, participate in PG&E's demand-side management programs such as energy efficiency and demand response. In areas such as San Francisco, PG&E states that when many customers became unbundled, it did not experience a decreased demand for customer engagement support services.[361] PG&E argues that the customer services provided through its Contact Centers and Customer Service Offices address issues regarding billing, payments, start, stop or transfer services, outages, gas leaks, and emergencies, which all affect both bundled and unbundled customers equally. PG&E argues that it also incurs costs for inquiries involving CCA issues, because CCA customers often call PG&E first with any service inquiry before PG&E can redirect the calls to the CCAs.

PG&E contests the JCCA's proposed methodology of using the rate of utilization to allocate costs, because customer usage of services is dynamic and changes over time. Also, because PG&E does not track utilization of customer service between bundled and unbundled customers, PG&E states that the data PG&E provided to the JCCAs and that the JCCAs used to develop the Adjusted Common Cost Allocator does not provide sufficient information to determine how costs were incurred and allocated based on the utilization of services by bundled and unbundled customers.

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[361] PG&E-20, Chapter 2 at 6.

PG&E argues that unbundled customers use customer services, such as those provided by the Contact Centers, at a higher rate per customer than bundled customers. PG&E argues that unbundled customers made more calls per customer (measured in April 2018) than bundled customers (measured in January 2018). PG&E hypothesizes that, because billing issues for unbundled customers are more complicated than bundled customers, unbundled customers make more service calls, and argues that these calls are often more complex and take longer to resolve.

PG&E contends that the data shows that Contact Center call volumes have increased from 2015 to 2017, while the number of departed customers tripled and the number of bundled generation customers declined by 15 percent. The JCCAs refute PG&E's claim, asserting that PG&E did not differentiate between calls handled by an automated system and calls handled by a customer service representative. According to the JCCAs, the data shows that, from 2015 to 2018, as more customers became unbundled, the calls attended by a customer service representative decreased by 13.7 percent, while calls answered by an automated system increased by 12.5, and thus the number of customer service calls handled by a representative decreased. The JCCAs argue that the customer services costs should decrease, because a decreased volume of calls attended by customer service representatives leads to less labor hours, while the cost of calls answered by an automated system should remain relatively flat even with the increased volume in calls.

13.4.4.3.2. Discussion

We determine that it is reasonable for PG&E to maintain its current functionalization of Customer Care costs, allocating Customer Care costs between gas distribution and electric distribution functions, based on the number of gas and electric service agreements. We find it appropriate to allocate the Customer Care costs following the principle of cost causation, which allocates costs to the group of customers that incur the costs.

Because the data does not clearly delineate the amount of support PG&E's customer care services provide to its individual utility functions (gas distribution, electric distribution or electric generation), the record is unclear as to whether generation customers use more or less customer care services than gas or electric distribution customers, or cause PG&E to incur more or less Customer Care costs than gas or electric distribution customers. Furthermore, the record data does not allow us to confidently extrapolate the extent of customer service usage by generation customers relative to gas or electric distribution customers, or the extent of costs generation customers impose on Customer Care services compared to gas or electric distribution customers. The JCCAs and PG&E each presented their interpretation of the record data. Each party pointed to flaws in the opposing party's data and arguments. But neither party's data nor their interpretation of the data is more convincing than the other.

The record does show that many of the customer care services support distribution issues that affect both bundled and unbundled customers equally. Both bundled and unbundled electric customers need customer support on issues related to system reliability, service planning, demand-side management programs, billing, payments, start, stop or transfer services, outages, gas leaks, and emergencies. Because the record shows that customer care services support bundled and unbundled customers equally on electric distribution issues but does not show that customer care services directly support PG&E's generation function, it is reasonable for PG&E to maintain its current functionalization of

Customer Care expenses to the electric distribution and gas distribution functions until we have better data showing the extent of customer service that PG&E provides for its generation and distribution functions.

The JCCAs request that the Commission direct PG&E to track and report data on how Customer Care services are used in the future to ensure that costs are more appropriately functionalized in future GRCs. PG&E opposes the JCCAs' request, arguing that tracking customer inquiries on whether the inquired issues pertain to electric generation or distribution is unduly burdensome.

PG&E currently tracks the purpose of its customer calls, with issues that include billing, start and stop services, scam, rate reform, solar, Spanish, and wildfire support.[362] Because of this current tracking, we are not persuaded of the accuracy of PG&E's back-of-the-envelope estimate of $656,000 to additionally track whether a customer call is related to electric generation or electric distribution.[363]

Therefore, to ensure that costs are appropriately functionalized to either its electric distribution or electric generation functions, we direct PG&E to track and report data showing the extent to which its Customer Care services and programs support its electric generation function as compared to its electric distribution and gas distribution functions. PG&E shall present this detailed data to justify and support its proposed cost allocation method of Customer Care expenses in its next GRC.

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[362] Hearing Exhibit 106; Transcript Volume 15 at 1586.

[363] Transcript Volume 15 at 1589.

13.4.5. Future Presentation of PG&E's Cost Allocation Proposals

The JCCAs request that the Commission require PG&E provide in future GRCs extensive detail and reasoning showing how costs are functionalized to support its cost functionalization process. The JCCAs propose that PG&E should (a) identify in each chapter of its testimony and by individual MWCs how costs are functionalized, (b) provide an explanation and evidence to support its proposed cost allocation methods, and (c) show how each program's cost allocation method relates to PG&E's cumulative functionalized revenue requirement.

The JCCAs argue that appropriate cost allocation methods are important to ensure that unbundled customers are not subsidizing bundled customers. The JCCAs assert that Pub. Util. Code Section 366.2 forbids cost shifts between departed customers and bundled customers. The JCCAs criticize PG&E's cost functionalization process and methods as opaque and argue that PG&E's initial testimony fails to explain and justify its cost functionalization process. According to the JCCAs, PG&E's cost allocation process does not allow the JCCAs to readily audit the data on how PG&E allocates costs among its electric generation, electric distribution, and gas distribution functions.

Pub. Util. Code Section 366.2(a)(4) states that "the implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation." Therefore, it is reasonable to implement measures to prevent cost subsidies between departed customers and bundled customers. An appropriate functionalization methodology is important to ensure that costs are appropriately allocated to its electric generation function, which only bundled customers pay, and electric distribution function, which both bundled and unbundled customers pay. Without an appropriate cost functionalization process, costs may be misappropriated between electric generation and distribution functions, possibly causing cost shifts between bundled and unbundled customers. To prevent possible cost subsidies between the bundled and unbundled customers, we direct PG&E to provide in its next GRC a better showing of its cost functionalization process. Specifically, we direct PG&E to provide in its next GRC detailed testimony showing and justifying how it allocates costs across its various utility functions, including how it derives its functional allocations. PG&E shall also include how PG&E functionalizes "common costs" and Customer Care expenses, given the additional data we directed PG&E to collect for its customer care operations.

14. Balancing and Memorandum Accounts

This section addresses the disposition of Balancing and Memorandum Accounts proposed in the Settlement Agreement.[364] The settlement includes modification, closure, and continuation of existing balancing and memorandum accounts and in certain cases, the disposition of current balances. The settlement also includes proposals to create new accounts. Most of the proposals regarding balancing and memorandum accounts are reviewed, discussed, and addressed as part of the discussion of other topics that the balancing and memorandum accounts address. For example, the Risk Transfer Balancing Account is discussed in the A&G section of the decision. In such cases, this section merely provides reference to the section of the decision where discussion of the account occurred.

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[364] Settlement Agreement Article 4.1.

For convenience, acronyms for regulatory accounts that have already been discussed in other sections of the decision are redefined here.

14.1. Modification or Closure of Existing Accounts

14.1.1. New Environmental Regulation Balancing Account (NERBA)

The NERBA is a two-way balancing account which records the difference between actual and adopted costs related to the 26 best practices associated with minimizing methane emissions as adopted by the Commission in the Natural Gas Leak Abatement Order Instituting Rulemaking (R.15-01-008). Modification of the distribution subaccount in the NERBA through 2022 for the sole purpose of tracking the costs associated with below ground Grade 3 leak repairs is discussed in the Gas Distribution section (Chapter 6).

14.1.2. Nuclear Regulatory Commission Rulemaking Balancing Account (NRCRBA)

The NRCRBA is a two-way balancing account which records the differences between actual and adopted expense and capital revenue requirements associated with compliance requirements. Modification of this account is discussed in the Energy Supply section (Chapter 8).

14.1.3. Hydro Licensing Balancing Account (HLBA)

The HLBA is a two-way balancing records expense and capital costs associated with hydro licensing. Modification of the HLBA to include regulatory fees, costs associated with implementation of the Crane Valley Recreation Settlement Agreement, and costs associated with work required due to the Oroville spillway incident is discussed in the Energy Supply section (Chapter 8).

14.1.4. Z-Factor Memorandum Account

The Z-Factor Memorandum account records costs associated with Z-Factor events or exogenous and unforeseen events that are largely beyond PG&E's

control but have material impact on costs. Modification of the Z-Factor memorandum account to include Z-Factor events in the TY is discussed in the PTY Ratemaking section (Chapter 17).

14.1.5. Vegetation Management Balancing Account (VMBA)

The VMBA is a two-way balancing account that records all of PG&E's vegetation management costs. Modification of the VMBA from a one-way into a two-way balancing account to record both routine and enhanced vegetation management expenses as well as the discontinuation of the Incremental Inspection and Removal Cost Tracking Account, is discussed in the Electric Distribution section (Chapter 7).

14.1.6. Fire Hazard Prevention Memorandum Account (FHPMA)

The FHPMA tracks costs related to fire hazard prevention in compliance with D.09-08-029. Closure of this account and recovery of any balance is discussed in the Electric Distribution section (Chapter 7).

14.1.7. Natural Gas Leak Abatement Program Balancing Account (NGLAPBA)

The NGLAPBA records the difference between actual and authorized costs of R&D related to methane emission reduction. Authority to close the NGLAPBA is discussed in the Gas Distribution section (Chapter 6).

14.1.8. Diablo Canyon Seismic Studies Balancing Account (DCSSBA)

The DCSSBA records the seismic studies costs. Authority to close this account is discussed in the Energy Supply section (Chapter 8).

14.1.9. AB 802 Memorandum Account (AB802MA)

The AB802MA records incremental costs associated with implementing requirements of AB 802 for maintaining and providing energy usage data to building owners and agents. Authority to close this account is discussed in the Customer Care section (Chapter 9).

14.1.10. Tax Memorandum Account (TMA)[365]

The TMA tracks differences in the authorized GRC revenue requirements related to income tax. Authority to modify PG&E's TMA to reflect the same interpretation as determined in D.19-09-051 is discussed in the RO section (Chapter 13).

14.2. Creation of New Accounts

14.2.1. Wildfire Mitigation Balancing Account (WMBA)

The WMBA is a two-way balancing account that will record CWSP-related expenses. Authority to establish the WMBA is discussed in the Electric Distribution section (Chapter 7).

14.2.2. Risk Transfer Balancing Account (RTBA)

Establishment of a two-way RTBA which will record the difference between the actual costs and amounts authorized in this GRC for excess liability insurance premiums is discussed under the A&G section (Chapter 12).

14.2.3. Dimmable Streetlight Implementation Memorandum Account (DSIMA)

Authority to create the DSIMA that will track implementation costs for the Dimmable Streetlight Program prior to 2023 is discussed in the Other Issues section of the decision (Chapter 18).

14.3. Continuing Accounts

14.3.1. Diablo Canyon Retirement Balancing Account (DCRBA)

The DCRBA is a two-way balancing account that records costs associated with the retirement of the DCPP. Continuation of the DCRBA is reasonable and

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365 The TMA is not specified in Article 4.1 of the Settlement Agreement but provisions regarding the TMA are found in Article 2.9.5.1 of the Settlement Agreement

should be authorized. Parties do not oppose continuation of this account or PG&E's proposal to transfer costs to the Utility Generation Balancing Account (UGBA) as discussed in the Energy Supply section of this decision (Chapter 8).

14.3.2. Major Emergencies Balancing Account (MEBA)

The MEBA is a two-way balancing account that records expense and capital costs resulting from responding to Major Emergencies that are not due to Catastrophic Event Memorandum Account (CEMA)-eligible events. Continuation of the MEBA is discussed in the Electric Distribution section of the decision (Chapter 7).

14.3.3. Catastrophic Emergencies Memorandum Account (CEMA)

The CEMA is a memorandum account that records incremental costs when there is a declaration of a state of emergency or disaster from a competent state or federal authority with respect to the event causing the emergency response. PG&E follows the criteria established in Resolution E-3238 and Pub Util Code § 454.9 to determine whether costs are eligible for CEMA recovery. Res. E-3238 authorizes PG&E to record incremental catastrophic event repair and restoration costs and compliance with governmental orders in connection with declared state and federal disasters. Continuation of the CEMA is discussed in the Electric Distribution section of the decision (Chapter 7).

14.3.4. Wildfire Expense Memorandum Account (WEMA)

The WEMA tracks wildfire damage costs to third parties. Continuation of the memorandum account for WEMA is discussed in the A&G section of the decision (Chapter 12).

14.3.5. Rule 20A Balancing Account (R20ABA)

The Rule 20A balancing account is a one-way balancing account that tracks the annual capital and expense costs for Rule 20A undergrounding projects.

Authority to continue this account is discussed in the Electric Distribution section (Chapter 7).

14.3.6. Statewide, Marketing, Education, and Outreach Balancing Accounts (SWMEOBA)

The SWMEOBA records the difference between actual and recorded statewide Marketing, Education, and Outreach expenses administered by PG&E. Continuation of this account is discussed in the Customer Care section (Chapter 9).

14.3.7. Residential Rate Reform Memorandum Account (RRRMA)[366]

The RRRMA tracks statewide marketing, education, and outreach contract costs related to residential rate reform under D.17-12-023. Continuation of the RRRMA is discussed in the Customer Care section (Chapter 9).

14.3.8. Accounts associated with safety-related Earnings Adjustment Mechanism (EAM)[367]

PG&E requested to modify various accounts to record rewards and penalties associated with its proposed safety-related shareholder EAM. This proposal was withdrawn as discussed in the Other Terms section of this decision (Chapter 16). Therefore, the following accounts shall continue without any modification from the EAM: (a) the Distribution Revenue Adjustment Mechanism (DRAM); (b) the UGBA; (c) the Core Fixed Cost Account (CFCA); and (d) the Noncore Customer Class Charge Account (NCA).

[366] The RRRMA is not specified in Article 4.1 of the Settlement Agreement but provisions regarding the RRRMA are included in Article 2.5.8 of the Settlement Agreement.

[367] The accounts associated with the EAM are also not specified in Article 4.1 of the Settlement Agreement but these accounts are associated with PG&E's safety-related EAM.

15. Other Adjustments

This section discusses the other adjustments to the Settlement Agreement set forth in Article 3. There are two adjustments relating to: (a) forecast update, concessions and errata; and (b) an adjustment to replace PG&E's 2018 capital forecasts with 2018 recorded capital expenditures.

15.1. Forecast Update, Concessions, and Errata

Article 3.1 states that the settlement includes a $13 million revenue requirement reduction for forecast updates, concessions, and errata. This adjustment is already incorporated into the Settlement Agreement and reflects adjustments that are included in PG&E's Joint Comparison Exhibits.[368] No further adjustments based on this provision are required.

15.2. 2018 Recorded Capital Costs

Article 3.2 provides that 2018 capital costs be based on PG&E's recorded capital costs for 2018. However, the Settlement Agreement adopts PG&E's 2018 capital forecasts and so this article requires PG&E to update its RO model to replace the 2018 capital forecast amounts specified in various sections of the Settlement Agreement with recorded 2018 capital amounts. PG&E's recorded capital expenditures for 2018 are slightly higher than its 2018 capital forecast.[369] The settlement proposes to conduct the above update upon filing of the implementation advice letter[370] once a final decision in this proceeding is adopted by the Commission.

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[368] Exhibit 311 Table 1-1.

[369] Recorded 2018 capital expenditures are approximately $3.917 billion while the 2018 forecast is approximately $3.847 billion.

[370] The implementation advice letter is the advice letter with revised tariff sheets that will be filed by PG&E to implement the revenue requirements that will be authorized in this decision.

Throughout its testimonies concerning capital projects under various topics, Cal Advocates has consistently recommended adopting PG&E's recorded capital costs for 2018 instead of PG&E's forecast costs. In its rebuttal testimony, PG&E states that it does not oppose Cal Advocates' recommendation to use recorded 2018 capital expenditures for purposes of rate base calculation.[371] PG&E's 2018 recorded capital expenditures reflect actual costs incurred during 2018 and in this case, are more accurate that PG&E's 2018 capital forecasts. PG&E also does not cite to any project delays or other reasons why it would be unreasonable in this case to adopt its recorded capital expenditures for 2018. In addition, PG&E does not specify that needed capital additions, expenditures, and improvements for 2018 were impaired or that needed projects would were not completed or discontinued. Thus, we find it reasonable in this case for PG&E to replace its 2018 capital forecasts with 2018 recorded expenditures and that doing so does nor impair PG&E's ability to provide safe and reliable services to its customers.

In the ALJ ruling dated May 15, 2020, we required the settling parties to submit documents showing the impact of replacing PG&E's 2018 capital forecasts with 2018 recorded capital expenditures pursuant to Article 3.2 of the Settlement Agreement and to make available upon request by the Commission, the impact of Article 3.2 on the RO Model. PG&E complied with the ruling by filing a Response on May 20, 2020.

Based on our review of Article 3.2 and the additional documents submitted by the settling parties, we find it reasonable to include the updated Appendices to the Settlement Agreement that reflect the 2018 recorded capital

[371] Exhibit 72 at 14-2 and 14-14.

expenditures as an additional appendix to the Settlement Agreement. We also find it reasonable to apply the updated RO model which incorporates the updated appendices to the attachments of this decision and to the overall revenue requirement being authorized in this decision and that doing so does not contravene the agreements set forth in the Settlement Agreement.

16. Other Terms

This section discusses the agreements set forth in Article 5 of the Settlement Agreement concerning other terms not already discussed in the preceding chapters and includes other issues which are of interest to specific parties.

16.1. Principles for Asset Replacement

The settling parties agree that PG&E should strive for steady state replacement of crucial operating equipment consistent with risk-informed decision making. This includes proactive replacement of assets prior to in-service failure and an evaluation and explanation will be included in PG&E's next RAMP submission. Parties that are not part of the settlement do not object to this proposal. We agree with the above proposal and find it reasonable.

16.2. Deferred Work Principles

The settling parties agreed on six principles set forth in Article 5.2[372] that will be applicable in PG&E's next GRC and Gas Transmission and Storage application concerning the level of work necessary to provide safe and reliable service. The six principles are as follows:

(1) Where funds are originally collected from ratepayers based o representations that the work is necessary to provide safe and reliable service and, yet, PG&E does not perform all of the designated work, the fact that PG&E must pay for a higher priority activity or program

[372] Settlement Agreement Article 5.2 at 36 to 37.

does not nullify or extinguish its responsibilities to fund forecasted and authorized work unless such work is no longer deemed necessary for safe and reliable service.

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

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

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

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

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

In addition, PG&E shall provide testimony explaining instances where work was authorized and funded but not all the work was performed although the work not performed is still necessary. In such instances, PG&E shall explain how and why the prior funding was re-allocated or used for other purposes in order to justify and properly evaluate the appropriateness of the new funding request for the work that had been deferred. Non-settling parties do not object to this provision in the settlement.

We reviewed the above provision and find that this addresses and balances PG&E's need to re-prioritize and reallocate funding for resources whenever appropriate but at the same time addresses a concern raised by TURN that funding for work that had not been performed had already been authorized and whether such deferred work was really necessary.

16.3. Risk Showing

The settling parties agree that PG&E's risk showing in its next RAMP Report and next GRC must comply with the settlement agreement in D.18-12-014. We agree with this provision and note that this resolves issues raised by TURN and Cal Advocates regarding RAMP integration in this GRC.

PG&E filed A.20-06-012 on June 30, 2020 in order to submit its RAMP Report for its TY2023 GRC. As part of the RAMP proceeding, the Safety Policy Division (SPD) will submit a report (SPD Report) assessing PG&E's risk analysis and modeling contained in PG&E's RAMP Report. PG&E shall then integrate SPD's assessment, along with comments from intervenors, into its next GRC. As part of its RAMP-related testimony in the next GRC, PG&E shall include information how it addressed or incorporated any concerns raised by SPD in the SPD Report.

In addition, the Commission issued Resolution WSD-002 on June 11, 2020 in connection with PG&E's Wildfire Mitigation Plan. The Resolution states that:

> RSE is not an appropriate tool for justifying the use of PSPS. When calculating RSE for PSPS, electrical corporations generally assume 100 percent wildfire risk mitigation and very low implementation costs because societal costs and impact are not included. When calculated this way, PSPS will always rise to the top as a wildfire mitigation tool, but it will always fail to account for its true costs to

> customers. Therefore, electrical corporations shall not rely on RSE calculations as a tool to justify the use of PSPS.[373]

Accordingly, in its next GRC, PG&E shall also include testimony that shows or explains how its RSE calculations comply with the above section of Resolution WSD-002 specified above.

16.4. Safety Related Earnings Adjustment Mechanism

PG&E is withdrawing its proposal to create a safety-related shareholder earnings adjustment mechanism that ties a portion of annual earnings to PG&E's safety performance. Various objections to the proposal were made by Cal Advocates, TURN, and FEA and the withdrawal of the proposal addresses those concerns.

16.5. Agreements with Other Parties

Separate memorandums of understanding (MOU) between PG&E and SBUA,[374] PG&E and CforAT,[375] and PG&E and NDC[376] are incorporated into the Settlement Agreement. The MOUs relate to PG&E's commitment to support small businesses, improving accessibility to its facilities, and providing outreach and education to minorities and promoting supplier diversity. We reviewed the MOUs and find them reasonable. The provisions and commitments included in the MOUs include enhancements to PG&E's efforts concerning these issues and resolves issues and concerns raised SBUA, CforAT, and NDC in this proceeding.

16.6. Other Issues of Interest to Specific Parties

Article 5.6 of the Settlement Agreement contains provisions regarding an Apprentice Lineman Training Program, a Dimmable Streetlight Program,

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[373] Resolution WSD-002 at 20.

[374] Settlement Agreement Appendix E.

[375] Settlement Agreement Appendix F.

[376] Settlement Agreement Appendix G.

management of change software, and job listing requirements for safety leader positions.

16.6.1. Apprentice Lineman Training Program

Article 5.6.1 of the Settlement Agreement provides that PG&E will continue to keep its Apprentice Lineman Training Program filled to the maximum extent. We agree with this provision and find that it is consistent with safe crew staffing ratios.

16.6.2. Dimmable Streetlight Program

The requirements and design of a dimmable streetlight program will be addressed in PG&E's Phase 2 GRC proceeding. All testimony and evidence in the record of this proceeding shall be incorporated by reference in the Phase 2 application. PG&E shall be allowed to create a Dimmable Streetlight Implementation Memorandum Account (DSIMA) to track any implementation costs incurred prior to 2023 and seek recovery of those costs in its next GRC application. The revenue requirement for the program will also be addressed in PG&E's next GRC. Finally, the settlement provides details regarding review of the City of San Jose's dimmable streetlight data since 2012 and possible past payments. We reviewed the provisions concerning the Dimmable Streetlight Program and agree with the general provisions concerning the program provided in the Settlement Agreement. The specifics are to be addressed in Phase 2 while revenue requirement issues are to be considered in PG&E's next GRC allowing the Commission multiple opportunities to further review details and specifics regarding the program. We also find appropriate the creation of the DSIMA which allows PG&E to track costs that may be incurred in this GRC period but which are not included in the revenue requirement to be determined in this GRC.

16.6.3. Issues Raised by OSA

The settlement includes a provision regarding implementation of Management of Change software for PG&E's gas, electric, and dam operations by December 2021 and for PG&E to submit an annual report to SED and OSA.[377] The settlement also includes that PG&E shall confer with SED and OSA regarding the qualifications of its safety work leaders in advance of PG&E's next GRC.[378] We agree with the above provisions and find that these provisions resolve issues raised by OSA regarding these areas.

17. Post Test Year Ratemaking

Post-Test Year (PTY) ratemaking is the ratemaking framework or mechanism that will be used to adjust PG&E's authorized revenue requirements in 2021 and 2022 in order to ensure that PG&E has appropriate levels of authorized revenues to address inflation and growth in rate base as well as additional capital investments.

In Article 2.1.2 of the Settlement Agreement, the settling parties agreed on revenue requirement increases of 3.50 percent or $318 million for 2021 and 3.90 percent or $367 million for 2022.

The above figures are lower than PG&E's original proposals of $454 million (+4.7 percent) for 2021 and $486 million (+4.8 percent) for 2022 but higher than Cal Advocates' originally recommended figures of $298 million (+3.3 percent) for 2021 and $329 million (+3.5 percent) for 2022. No other party provided an overall revenue requirement recommendation for the PTYs.

The table below shows these differences in tabular form:

[377] Settlement Agreement Article 5.6.3.1. The report should be submitted to OSA's successor.

[378] Settlement Agreement Article 5.6.3.2.

PTY Amounts	2021	2021(%)	2022	2022(%)
Settlement	$318 million	3.5%	$367 million	3.9%
PG&E's original proposal	$454 million	4.74%	$486 million	4.85%
Cal Advocates' original proposal	$298 million	3.3%	$329 million	3.5%

17.1. Discussion

PG&E's original proposal is based on a mechanism that applies a different methodology to calculate O&M and capital costs for the PTYs. Generally, the mechanism applies escalation to O&M costs and models capital revenue requirement growth based on plant additions.[379]

For O&M escalation, PG&E had proposed to apply an escalation rate to TY adopted amounts based on the best source available to project cost escalation for each expense category. Thus, different escalation rates would be applied to: labor-related expenses based on an external survey; materials and services based on Global Insight escalation rates; and medical plan costs based on an actuarial study conducted by an outside company named Mercer.[380] Exceptions to the application of a simple escalation rate are made for vegetation management costs related to overhang clearing, declining expenses associated with the projected closure of the DCPP, and the statewide rate reform marketing and education outreach because these are expected to follow a normal pattern of escalation over the years included in this rate case cycle. For these exceptions, specific expense

[379] Exhibit 53 at 1-1.

[380] *Id* at 2-4 to 2-6.

adjustments to the TY amounts were calculated based on projected costs in 2021 and 2022. The specific amounts are provided and discussed in Exhibit 53.[381]

For capital costs, PG&E's proposal is to base the capital revenue requirement on rate base growth resulting from plant additions plus escalation, forecasted depreciation, and estimated changes in deferred tax liabilities. Escalation will be based on Global Insight's utility capital escalation except for plant additions under nuclear generation, hydro generation, and corporate real estate because of an uneven forecast of plant additions.[382] For these exceptions, PG&E proposed a "bottom-up forecast"[383] of PTY capital additions.

On the other hand, Cal Advocates' original proposal was based on the attrition increases adopted by the Commission in recent large energy utility GRCs and a recent IHS Global Market forecast of the consumer price index (CPI) and incorporating the expense and revenue adjustments relating to vegetation management costs related to overhang clearing, declining expenses associated with the projected closure of the DCPP, and the statewide rate reform marketing and education outreach.[384] Alternatively, if the Commission was inclined to follow PG&E's proposed method, then Cal Advocates proposes a different method for calculating capital additions and a different escalation rate for labor-related expenses.[385]

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381 *Id* at 2-6 to 2-7.

382 *Id* at 2-6.

383 A bottom-up forecast is a forecasting method that starts with company data and then broadens up to revenue. This is in contrast to a top-down forecast that begins with revenue and then works down to detailed plans and operating expenses.

384 Exhibit 248 at 17 to 19.

385 *Id* at 21 to 25.

A review of the PTY proposal in the Settlement Agreement shows that the method for determining the PTY revenue requirements more closely follows PG&E's original method rather than Cal Advocates' primary recommendation based on the data provided in Exhibit C of the Settlement Agreement which provides separate PTY totals for Electric Generation, Electric Distribution, and Gas Distribution rather than a single escalation rate for all costs. Cal Advocates' alternate recommendation also follows PG&E's proposed method but with different methods for calculating escalation for labor-related expenses and capital additions. From our review, we find no issue with basing the general method for determining the PTY revenue requirements using the general method proposed by PG&E of applying escalation to determine O&M costs and basing capital revenue requirement growth on plant additions.

However, even applying the same general PTY ratemaking framework results in several differences between PG&E's and Cal Advocates' proposals as the two parties recommended different indexes for determining labor-related escalation and different methods for calculating the cost of capital additions.

After reviewing the Settlement Agreement as a whole and considering the evidence in the record, we find the proposed PTY amounts in the Settlement Agreement represent a fair compromise between the testimony and arguments presented by both PG&E and Cal Advocates. In this case, both parties presented reasonable arguments in support of their positions but neither party was able to establish that their recommended method is better than the other. Thus, we find that the values presented in the settlement, which is within the range of outcomes recommended by the two parties, is a reasonable compromise between the two parties. The settling parties agree with the settlement amounts and both settling and non-settling parties did not directly oppose either PG&E's or Cal Advocates' originally recommended methods.

In view of the above, we find the PTY increases of $318 million (3.5 percent) for 2021 and $367 million (3.9 percent) in Article 2.1.2 of the Settlement Agreement reasonable and should be authorized. However, these amounts should be revised to reflect reductions to the authorized amounts for CWSP capital for 2021 and 2022 as discussed in the WMBA section of the decision (Section 7.4).

17.2. Z-Factor

The settlement proposes continuation of PG&E's Z-factor memorandum account[386] that will record costs associated with Z-factor events in TY2020 and PTYs 2021 and 2022. The Z-Factor mechanism uses a series of eight criteria described in D.94-06-011 to identify exogenous cost changes that qualify for rate adjustments prior to PG&E's next GRC test year.[387] Rate adjustments are allowed for only the portion of Z-Factor costs not already contained in the annual revenue requirement.

We agree with continuation of the Z-Factor memorandum account to track costs associated with exogenous and unforeseen events that are largely beyond PG&E's control but have a material impact on costs after base rates have already been set for this GRC cycle. We also have no issues with tracking Z-Factor

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[386] Settlement Agreement Article 4.1.1.4.

[387] The eight criteria are as follows: 1. The event must be exogenous to the utility; 2. The event must occur after implementation of rates; 3. The costs are beyond the control of the utility management; 4. The costs are not a normal part of doing business; 5. The costs must have a disproportionate impact on the utility; 6. The costs must have a major impact on overall costs; 7. The cost impact must be measurable; and 8. The utility must incur the cost reasonably.

events that may occur during the TY consistent with D.19-09-051.[388] Lastly, Article 4.1.1.4 does not specify but we assume that each Z-Factor event will only include costs in excess of a $10 million deductible per event as specified in PG&E's unopposed testimony regarding this issue.[389]

18. Issues Outside the Settlement Agreement

18.1. Microgrid Resilience Zones

The Resilience Zone program is part of PG&E's proposed CWSP. The Resilience Zones are intended to provide localized temporary power to communities impacted by PSPS events. In this GRC, PG&E requests to recover the costs of establishing the interconnection capabilities for the Resilience Zones. Please see the Electric Distribution chapter for a more detailed discussion of PG&E's request for cost recovery of its Resilience Zone program in this GRC.

18.1.1. JCCA's Position

The JCCAs propose several changes to PG&E's Resilience Zone program.

First, the JCCAs request that PG&E coordinate and collaborate with local governments through their CCAs in planning the construction of Resilience Zones that are within the CCAs' service territories. Second, the JCCAs request that Resilience Zones in the CCA territories accommodate generation that the CCAs procure. Third, the JCCAs propose expanding the scope of PG&E's proposed resiliency zones to include funding for permanent clean generation and storage onsite at the Resilience Zones, such as a system using solar generation and energy storage. Fourth, the JCCAs argues that PG&E needs to accelerate the pace of Resilience Zone deployment, noting that PG&E brought only one of 40 proposed Resilience Zones into operation in one year.

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[388] D.19-09-051 at 682 to 683.

[389] Exhibit 248 at 1-4.

Lastly, the JCCAs argue, unless the Resilience Zones can accommodate CCA-procured generation in locations determined through partnering with the CCAs and include permanent, clean onsite generation and storage, costs for the development of the Resilience Zones should be allocated solely to the generation revenue requirement.

18.1.2. PG&E's Position

PG&E argues that all the issues the JCCAs raise, except for the cost allocation of the Resilience Zone program, are out of the scope of this proceeding and should be addressed in Rulemaking (R.) 19-09-009 (Microgrid OIR). PG&E states that it submitted a proposal in the Microgrid OIR that addresses many of the generation-related issues raised by the JCCAs.

In response to the JCCAs' claim that PG&E is providing generation through the Resilience Zones, PG&E clarifies that it is not seeking in this proceeding to interconnect the Resilience Zones with generation resources, own the generation that interconnect with the Resilience Zones, or recover costs for any generation equipment at the Resilience Zones.

As for the JCCAs' criticism of PG&E's pace in developing the Resiliency Zones, PG&E agrees with the JCCAs that it should accelerate the pace of Resilience Zones deployment. PG&E states that it is working aggressively to design, permit and construct more Resilience Zones as quickly as possible.

18.1.3. Discussion

We address the cost allocation issue the JCCAs raise for the costs of the Resilience Zones in the Cost Allocation of the RO chapter.

Other than the cost allocation issues, we determine that the Resilience Zone issues raised by the JCCA are out of the scope of this proceeding and are more appropriately addressed in R.19-09-009 (Microgrid OIR). D.20-06-17, issued in the Microgrid OIR, adopts solutions to accelerate Microgrid deployment and addresses many of the JCCAs' issues. In particular, the decision directs the utilities, including PG&E, to collaborate with local government agencies, including CCAs, in planning the establishment of the Resilience Zones to respond to local needs. Recognizing that local jurisdictions best understand local issues and response capabilities, the decision directs PG&E to coordinate with county emergencies service agencies. Most importantly, the decision addresses the generation PG&E is to use in the Resilience Zones, through the adoption of PG&E's Distributed Generation Enabled Microgrid Services (DGEMS) Make-ready Program,[390] Temporary Generation Program,[391] and Community Microgrid Enablement Program (CMEP).[392]

18.2. Grid Modernization Plan Projects

18.2.1. Positions of the Parties

The IGP is part of PG&E's Grid Modernization Plan to add more advanced monitoring, control, forecasting functionality, and cybersecurity functions to the grid. PG&E proposes to recover the costs of the IGP in this proceeding. A more detailed discussion of the IGP costs can be found in the Electric Distribution chapter.

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[390] The DGEMS Make-Ready Program enables a set of chosen substations to operate in islanded mode when the transmission line serving the substation is de-energized, such as during a PSPS event or other loss of the transmission line (*i.e.*, severe weather, earthquake, physical or cyber security event). *See* D.20-06-017 at 68-88.

[391] The Temporary Generation Program deploys temporary mobile distributed generation as a critical near-term stop-gap solution during PSPS events. *See* D.20-06-017 at 68-88.

[392] The CMEP provides technical and financial support to local and tribal governments for establishing community-requested, critical facility microgrids to mitigate PSPS events. *See* D.20-06-017 at 68-88.

The Grid Modernization Plan projects, including the IGP, allows PG&E to obtain real-time energy data from the grid. The JCCAs request that the Commission direct PG&E to share with CCAs, as well as other load-serving entities, the real-time energy data obtained through the Grid Modernization Plan projects. According to the JCCAs, access to the real-time energy data will help them plan generation procurement, locate DERs, and evaluate the economic performance of existing DER programs. If access is provided, the JCCAs assert that they will have to pay extra for additional tools to obtain the same type of real-time energy data.

Since PG&E proposes to recover grid modernization costs through electric distribution rates, which both CCA customers and bundled customers pay, the JCCAs argue that PG&E should share the benefits of the grid modernization investments with CCA customers by giving CCAs access to the real-time energy data. Otherwise, the JCCAs propose that the grid modernization costs should also be allocated to generation rates, because, according to the JCCAs, bundled customers would share a larger portion of the grid modernization benefits and should bear more of the grid modernization costs.

In response, PG&E argues that the issue of access to real-time energy data enabled by the IGP is more appropriately addressed in the Distributed Resource Planning (DRP) proceeding, R.14-08-013. PG&E argues that the issue of real-time data enabled by the grid modernization projects concern the future market for grid services, raising questions such as whether access to the real time energy data provides any competitive advantage in a future electric distribution market. Enabling access to real-time data, according to PG&E, will require PG&E to invest in cybersecurity improvements and data integrations with third parties and raise complex new security and customer privacy issues that would require costly IT integrations. PG&E recommends that the Commission give due consideration weighing the associated benefits, costs, and security risks of allowing the real-time energy data to be shared.

18.2.2. Discussion

The Commission will need to weigh and consider many of the benefits and costs associated with allowing third party access to the real-time energy data that the grid modernization projects enable PG&E to obtain. Additionally, in considering whether to grant third party access to the utility data, the Commission will also need to consider how allowing access impacts other energy utilities besides PG&E. We determine that these considerations are more appropriately addressed in the DRP proceeding, R.14-08-013, in which the Commission can consider how these policies can affect multiple utilities.

In the meantime, as the Commission address the issue of access to grid modernization data in the DRP proceeding, we determine that it is reasonable to currently allocate the IGP costs, or grid modernization costs, to the electric distribution function. We explain how we determine the cost allocation of IGP costs in the Cost Allocation section found in the RO chapter. As discussed in the Cost Allocation section, we direct PG&E to examine the cost allocation of grid modernization costs and include detailed explanations and support to justify its proposed allocation of grid modernization costs in its next GRC filing. After the Commission address the issue of data access, the parties may propose modifications to the current cost allocation of grid modernization costs.

18.3. Compliance with the United States District Terms of Probation

L. Jan Reid states that PG&E must meet five conditions under its probation with the United States District Court, which includes having a Monitor to assess PG&E's wildfire mitigation and wildfire safety work and reporting to the

Monitor on the first business day of every month on its vegetation management status and progress. L. Jan Reid recommends that the Commission order PG&E to file a monthly advice letter to 1) inform the Commission of any written assessment performed by the Monitor related to PG&E's wildfire mitigation and wildfire safety work and 2) provide a copy of PG&E's vegetation management report to the Monitor.

PG&E's compliance with the United States District Court's probation is not an issue within the scope of the GRC.

18.4. PG&E's Bankruptcy

L. Jan Reid expresses concerns of how the outcome of PG&E's bankruptcy proceeding could have an impact on the Commission's disposition of this proceeding, such as whether bondholders may get a majority stake in the Company and attempt to sell off assets or reduce safety spending.

Issues related to PG&E's bankruptcy are outside the scope of this proceeding.

19. Conclusion

In the preceding chapters of this decision, we reviewed the various terms of the Settlement Agreement and presented our discussion generally following the topics in Articles 2 to 6 of the Settlement Agreement. We also explained in Chapter 5 how reviews of the various settlement terms and non-settled issues were conducted.

We gave due regard to the agreement reached by the settling parties and considered the proposed revenue requirements and other terms as whole. However, we also considered that not all parties are part of the Settlement Agreement. In addition, we also considered the complex nature of GRCs and the fact that the settlement includes a multitude of terms, provisions, and agreements reached by the settling parties.

Based on our review, we find the Settlement Agreement reasonable in light of the record as a whole, consistent with law and prior Commission decisions, and in the public interest except with respect to the following terms in which we recommend modifications to the Settlement Agreement:

a. As discussed in Section 7.2.5.4 of this decision, the proposed VMBA should be modified such that recovery of costs in excess of 130 percent of the authorized amount for VM shall be made by application instead of a Tier 3 advice letter.

b. As discussed in Section 7.4, the authorized capital amounts and unit costs for System hardening should be revised as follows:

   CWSP Capital: $603.341 million for 2021 and 2022

   Overhead per Circuit Mile Cost: $1.2 million for 2021 and 2022

   Underground per Circuit Mile Cost: $4.4 million for 2021 and 2022.

   As a result, the proposed revenue requirements for 2021 and 2022 should also be adjusted to reflect the above changes to the authorized CWSP amounts.

c. As discussed in Section 7.4, the proposed WMBA should be modified such that recovery of costs, in excess of 130 percent of the authorized amounts for CWSP O&M and capital projects or if recorded average per circuit mile unit costs exceed 130 percent of the authorized per circuit mile unit cost, shall be made by application instead of a Tier 3 advice letter.

d. As discussed in Section 7.5, recovery of other fire risk mitigation capital expenditures not included in this GRC should be made by application instead of via a Tier 3 advice letter.

e. As discussed in Section 9.4.5, the closure of up to 10 branch offices should be filed via a Tier 32 Advice Letter which allows the Commission to review the proposed closures instead of leaving the matter within PG&E's sole discretion. The advice letter shall also indicate the amount of savings PG&E will achieve through the CSO closures, the selection criteria used to select the CSOs for closure, the timing of the proposed closures, and updated 2018 and 2019 data pertaining to the selection criteria.

f. As discussed in Section 12.2.6, the proposed RTBA should be modified such that recovery of costs, in excess of 130 percent of the authorized amount for General Liability insurance shall be made by application instead of a Tier 2 advice letter.

g. As discussed in Section 15.2, the updated RO model reflecting recorded 2018 capital expenditures[393]should be attached to the Settlement Agreement as an additional appendix.

The Commission has historically favored settlements that are fair and reasonable in light of the record as a whole and except for the proposed modifications described above, we find the Settlement Agreement reasonable in light of the record as a whole and that the settlement does not contravene any statutory provisions, Commission's rules, or prior Commission decisions. In addition, the Settlement Agreement provides sufficient information for the Commission to discharge its future regulatory obligations with respect to the parties and their interests and obligations.

The Settlement Agreement is also in the public interest. The settling parties fairly represent the interests of the public affected by the transaction. The adopted revenue requirements, other than those pertaining to the modifications described above, will enable PG&E to comply with its obligations under Pub. Util Code § 451 to provide safe and reliable service at just and reasonable rates. Issues and concerns raised by non-settling parties such as JCCA and FEA were reviewed, considered, and addressed.

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[393] The updated RO model was submitted by PG&E pursuant to the ALJ ruling on May 15, 2020. And as discussed in Chapter 15, recorded 2018 capital expenditures are approximately $3.917 billion while the 2018 forecast is approximately $3.847 billion.

Other than the proposed modifications to the Settlement Agreement discussed in the relevant sections of the decision as specified above, we approve the Settlement Motion and the corresponding Settlement Agreement between PG&E, Cal Advocates, TURN, SBUA, CforAT, NDC, CUE, CALSLA, and OSA.

With respect to the proposed modifications specified above, each of the settling parties can elect to accept the proposed modifications jointly or individually as part of their comments to the decision. The settling parties shall also file a "Notice to Accept" the proposed modifications to the Settlement Agreement within 15 days from the date of this decision pursuant to Rule 12.4(c) of the Commission's Rules.

If any of the settling parties choose not to accept any of the proposed modifications, such party may file a "Motion Requesting Other Relief," within 15 days from the date of this decision in lieu of the "Notice to Accept." In the event a "Motion Requesting Other Relief" is filed in connection with this proceeding, then the Settlement Motion shall be rejected and a decision shall be issued in due time addressing each party's final position prior to the settlement. The proceeding shall be extended by another 18 months as provided for in Pub. Util. Code Section 1701.5.

Parties should note that the conclusions arrived at in this decision reflect due consideration given to the provisions in the Settlement Agreement and agreements reached by the settling parties. If the Settlement Motion is denied, the next decision that resolves the various issues in the proceeding may include different conclusions than the accepted forecasts and requests discussed in this decision.

19.1. Issues Raised in Opening Briefs

As stated in the Procedural Background of the decision, opening briefs were filed by A4NR, WEM, Reid, and JCCA for the purpose of addressing issues that are outside the Settlement Agreement. All four are non-settling parties. All issues raised in said briefs that are within the scope of this GRC proceeding such as PG&E's IGP and Grid Modernization Plan, CSO office closures, Customer Care and Customer Engagement issues, the purchase of four firefighting helicopters, other CWSP issues, cost allocation issues, etc., have been discussed and addressed in the appropriate chapters of the decision. Arguments and testimony submitted by other non-settling parties such as FEA, WEM, A4NR, etc. are likewise addressed in appropriate sections of the decision.

A few issues that are not part of the Settlement Agreement such as the issues raised by JCCA concerning microgrid resilience zones and grid modernization plan projects are discussed in the chapter concerning issues that are outside the settlement (Chapter 18).

On the other hand, arguments and requests raised in Opening Briefs concerning issues that are outside the scope of the proceeding such as rate increases related to other Commission proceedings, non-related issues pertaining to PG&E's bankruptcy filing, compliance with the U.S. District Court's probation order, etc., are not addressed in this GRC.

20. Category and Need for Hearing

In Resolution ALJ 176-3430 dated January 10, 2019, the Commission preliminarily categorized both applications as ratesetting as defined in Rule 1.3(e) and determined that evidentiary hearings are necessary. We affirm that the category for this proceeding is ratesetting and evidentiary hearings were held from September 23, 2019 to October 18, 2019.

21. Comments on the Proposed Decision

The proposed decision of the ALJs in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____________ by the following:

22. Assignment of the Proceeding

Commissioner Liane M. Randolph is the assigned Commissioner and Rafael Lirag and Elaine Lau are the assigned ALJs in this proceeding.

Findings of Fact

1. In Resolution ALJ 176-3430 dated January 10, 2019, the Commission preliminarily categorized the application as ratesetting as defined in Rule 1.3(e) and determined that evidentiary hearings are necessary.
2. PG&E's GRC application seeks Commission authority to establish its gas, electric distribution, and electric generation base revenue requirement for TY2020 and PTYs 2021 and 2022 beginning January 1, 2020.
3. According to PG&E, the requested revenue requirement is what PG&E needs to provide safe and reliable gas and electric service to its customers and includes work that reflects new approaches to the design, construction, and operations and maintenance of its electric distribution system to focus on and address increased wildfire risks particularly in high fire-risk locations.
4. D.19-11-004 authorized PG&E to establish a GRCMA that will record the difference in the revenue requirement that is effective on January 1, 2020 and the final revenue requirement adopted in this decision for TY2020.
5. The proposed Settlement Agreement that was filed resolves all issues amongst the settling parties.

6. The Settlement Agreement includes proposed revenue requirements for TY2020 and PTYs 2021 and 2022 and disposition of balancing and memorandum accounts that are specified in the Settlement Agreement.

7. Throughout the decision, PG&E's forecasts generally refer to PG&E's adjusted forecasts representing its final position prior to the Settlement Agreement.

8. The labor escalation adjustments adopted in the Settlement Agreement are generally lower than PG&E's originally proposed escalation rates.

Gas Distribution

9. Gas distribution O&M expenses are for operations work activities related to labor and expenses, storage, operations supervision and engineering, main and service expenses, measurement and regulator storage expenses, other gas distribution expenses, maintenance supervision and engineering, maintenance of mains and services, measurement and regulator station expenses, maintenance of meters and house regulators, and maintenance of other equipment.

10. Some of the specific work performed by Gas Distribution includes leakage surveys, leak repairs, application of corrosion control measures, valve maintenance, monitoring meter accuracy, adding odorant to gas, and locating and marking buried pipes to avoid damage caused by third-party dig-ins.

11. The settlement reduces PG&E's proposed forecast for Gas Distribution O&M costs by $5.0 million. Specifically, the reduction is in PG&E's forecast for MPP costs under Distribution and Mains.

12. As discussed in the Gas Distribution section, the O&M forecasts for Distribution Operations and Management Programs, Leak Management, Gas System Operations, and New Business and WROs are reasonable.

13. From 2014 to 2017, PG&E identified approximately 39,038 AOCs that need remediation work.

14. PG&E did not sufficiently establish why remediation work for AOCs under Distribution and Mains must be completed within three years.

15. The funding level adopted by the settlement for MPP results in a pace of AOC remediation work that more accurately reflects the level of work that will be conducted based on the testimony presented.

16. The proposed unit costs adopted by the settlement for PG&E's cross-bore program is reasonable and allows PG&E to perform close to its planned inspections while addressing the uncertainty regarding the number of UTA inspections that cannot be performed.

17. The adopted agreement for the cross-bore program allows PG&E to conduct additional non-UTA inspections as a substitute for UTA inspections that it cannot perform due to access issues.

18. PG&E's forecast to install sulfur filters at all regulator locations under Asset Family: Measurement & Control and CNG correctly calculates individual cost, number of sulfur filter station installations to be made, and additional installations that will be made beyond the test year.

19. The forecast for Cathodic Protection takes into account initial delays for ECPS and casing mitigation of pipelines and full implementation of the Casing Mitigation program.

20. The forecast methodology utilized for Gas Operations Technology & Other Distribution Support is reasonable.

21. Below ground Grade 3 leak repair costs are more appropriately tracked in the NERBA because the NERBA tracks costs associated with the 26 best practices adopted by the Commission in the Leak Abatement OIR.

22. Below ground Grade 3 leak repair relates to compliance with best practice number 21.

23. As discussed in the Gas Distribution section, capital projects for Gas Distribution Operations & Maintenance Programs, Leak Management, New Business and WRO, and Gas Operations Technology and Other Distribution Support are reasonable.

24. The settling parties agreed on a total replacement rate of 417 miles of pre-1985 Aldyl-A and similar plastic pipes with a total cost of $1.231 billion for this GRC cycle.

25. A slam shut device provides added protection against over-pressure and is considered an industry best practice.

26. The Over-Pressure Enhancements program is designed to address one of PG&E's top enterprise risks identified in its RAMP Report.

27. Although over-pressure events do not occur frequently, potential damage may be catastrophic.

28. Corrosion Control capital projects experienced a shortfall in spending in 2018 due to retirements and re-deployment of personnel and resources for wildfire response.

29. Capital projects to install new mains, regulators, and regulator components under Gas Systems Operation Capital experienced delays in 2018 but the forecast for 2019 is impacted more by demand for new installations as opposed to actual projects completed during the previous year.

Electric Distribution

30. Electric Distribution costs also include programs and activities aimed at reducing wildfire risk through PG&E's CWSP as well as programs and activities

to modernize PG&E's electric grid and the foundation for an IGP to address evolving distribution resource needs such as integration of DERs.

31. In the last GRC (TY2017), PG&E put in place programs to mitigate wildfire risks referred to as Control programs. PG&E plans to continue these programs in this GRC.

32. During the RAMP process, PG&E identified six additional programs to mitigate wildfire risks and PG&E plans on adding these to its Control programs.

33. After the 2017 October wildfires however, PG&E identified more mitigation programs in addition to those identified during the RAMP process and created the CWSP to comprehensively address wildfire risks.

34. The CWSP is an integrated wildfire mitigation strategy that incorporates a risk-based approach to identify and address PG&E's assets that are most at risk from the threat of wildfires and its associated events and is primarily responsible for performing wildfire risk assessment and identifying wildfire risk mitigation work.

35. The five main programs of CWSP are EVM, Wildfire System Hardening, Enhanced Operational Practices, Enhanced Situational Awareness, and Other Support Programs.

36. Electric Distribution O&M expenses are for work activities related to operation, supervision, and maintenance associated with the electric distribution system, load dispatching, station expenses, overhead and underground lines, poles, street lighting, customer installations, tree trimming, line transformers, and miscellaneous work.

37. As discussed in the Electric Distribution chapter, the settlement reduces PG&E's proposed O&M forecast of $1.026 billion by approximately $59.338

million exclusive of labor escalation adjustments. All of the reductions are for VM.

38. As discussed in the Electric Distribution chapter, the O&M amounts adopted by the Settlement Agreement for EP&R, EER, DSO, EDM, VM, Pole Asset Management, DAP, Substation Asset Management, Engineering and Planning, Electric Distribution Technology, New Business and WRO, Electric Distribution Support Activities, and IGP & Grid Modernization Plan are reasonable.

39. The EP&R organization is responsible for preparing PG&E to respond to catastrophic incidents such as earthquakes, high wind events, wildfires, drought, flooding, and mudslides.

40. The programs included under EP&R are additional precautionary measures that PG&E implemented after the wildfires in 2017 which are intended to further reduce the risk of wildfires.

41. PG&E's forecast for EP&R includes incremental funding for many new or enhanced initiatives and activities related to its CWSP such as costs for the WSOC, PSPS community outreach, wildfire detection meteorology projects, wildfire cameras, enhanced wire down detection, and safety and infrastructure teams.

42. The CWSP activities under EP&R are reasonable and necessary measures to enhance PG&E's wildfire mitigation efforts and PG&E provided support for its cost estimates.

43. PG&E will continue other wildfire mitigation efforts such as expanded weather station deployment, advance fire modeling, costs relating to satellite fire detection, and costs relating to storm outage prediction and model automation.

44. Many of the new CWSP activities under EP&R were only being initiated in 2018 and comparative expenditures in 2018 for the above activities are significantly less than the forecasts for TY2020.

45. The EER organization is responsible for work in response to routine and major emergencies and includes responding to incidents and outages during emergencies, performing equipment repairs and replacements related to emergencies, and providing staffing for emergency centers.

46. Although costs under EER are associated with recurring emergency work that PG&E conducts every year, costs remain difficult to predict as activities are dependent on the number and severity of emergencies that occur.

47. Reasonableness of the CEMA and MEBA has already been addressed in PG&E's prior GRC and we make the same findings regarding continuation of these two accounts.

48. The DSO organization continuously monitors the electric distribution system, manages outage restoration, directs system switching, and manages electric-related customer service field work.

49. DSO costs in TY2020 are higher due to escalation, re-assignment of personnel for scheduling and dispatching, directing safe response to outages and 911 calls, support for implementation and operation of reclose blocking wildfire risk mitigation, and O&M costs for a capital project relating to critical operating equipment.

50. The EDM organization is responsible for conducting patrols and inspections as well as routine maintenance of PG&E's electric distribution facilities.

51. The settlement adopts PG&E's forecast for EDM which were developed using program specific factors as opposed to simply relying on historical

averages and the forecast takes into account expanded patrol, inspection, and maintenance activities to further mitigate wildfire risk.

52. The settlement combines the amounts forecast for routine VM and enhanced VM.

53. Routine VM includes the costs to patrol, inspect, and maintain clearance for trees along high voltage distribution lines as well as routine tree pruning and removal, contractor quality control, environmental compliance, public education, and fire risk reduction work.

54. Routine VM consists of work already being performed by PG&E and this kind of work has already been reviewed in PG&E's prior GRC and found to be necessary and reasonable work to aid in wildfire mitigation efforts.

55. Routine VM work complies with General Order 95, Rules 35 and 37, and sections 4292 and 4293 of the California Public Resources Code.

56. Enhanced VM began in 2018 and includes work intended to reduce wildfire risk in Tier 2 and Tier 3 HFTDs such as overhang clearing, targeted tree species work, fuel reduction, and light detection and ranging.

57. The general scope of VM work is important in mitigating wildfire risks.

58. The scope of work for VM is not clearly defined and the pace of work planned is unpredictable.

59. 2018 is also the only year where enhanced VM has been performed and there are no other years that can be used as a historical reference for programs and projects and costs.

60. Most of the projects and programs for enhanced VM proposed in the TY are substantially the same as those performed in 2018.

61. Costs for enhanced VM includes incremental funding for the PTYs.

62. Tracking both routine and enhanced VM costs into a single balancing account promotes efficiency as the activities conducted are similar.

63. The enhanced VM program is new and a proper forecast that balances the need for affordable rates with work that needs to be performed is difficult to determine.

64. The scope of enhanced VM activities continues to be refined and a more conservative estimate of VM costs is more prudent at this point given the other incremental activities being proposed under the CWSP.

65. The VMBA will enable PG&E to act with less delay in case further mitigation activities and additional costs above the authorized level become necessary to mitigate wildfire risk but allows the return of excess funds not utilized to ratepayers.

66. As discussed in the VMBA section, provisions concerning VM tracking, reporting, and the targeted tree species study provided in Articles 2.3.4.4 to 2.3.4.6 of the Settlement Agreement are reasonable.

67. The additional provisions regarding VM render the IIRCTA sub-account unnecessary.

68. PG&E proposes to continue activities relating to pole inspection, maintenance, and restoration that were already being conducted in its prior GRC.

69. The settlement amount for Pole Asset Management does not deviate greatly from recorded expenses in 2017.

70. The DAP program covers installation, upgrade, and replacement of remotely controlled automation and protection equipment in both distribution substations and on feeder circuits and the forecast amount will provide engineering support for automation and protection equipment.

71. The settlement amount for DAP does not differ greatly from recorded 2017 expenditures.

72. DAP improves operating efficiency, enables better outage response and diagnosis, improves system protection, provides wildfire risk management, and improves safety by enabling PG&E to automatically and remotely shut off electricity during emergencies.

73. PG&E's Substation Asset Management organization is responsible for managing the repairs and maintenance of equipment located in approximately 760 electric distribution substations.

74. The forecast for Substation Asset Management is for work that has been regularly conducted in previous years but includes funding for six Major Emergency Corrective Maintenance programs that will be completed in 2018 and 2019.

75. Electric Distribution Engineering and Planning costs primarily cover labor expenses that support a variety of asset management activities and one of the programs, the APC, performs diagnostics on data from automated field equipment to support PG&E's distribution control centers.

76. PG&E provided a cost estimate worksheet with working formulas that sufficiently explain projected costs for each of the APC's three main functions and that explains that increases in APC costs are primarily due to ramp-up of the APC in 2018.

77. O&M costs for Electric Distribution Technology correspond to the O&M portion of capital projects and support ongoing maintenance, operations and repair for PG&E's IT applications, systems and infrastructure.

78. New Business involves activities relating to the installation of electric infrastructure required to connect new customers while WRO activities relate to

the relocation of PG&E's existing electric facilities at the request of customers and governmental agencies, which include undergrounding of existing overhead electric facilities.

79. EGI fees in 2016 were reflected as credits in 2017 and 2018 leading to higher costs beginning in 2019 because the EGI credits have been zeroed out.

80. Electric Distribution Support Activities provide resources and staffing to assist PG&E's Electric Operations business units with managing various programs and projects.

81. The scope of activities for Electric Distribution Support Activities has changed significantly since 2017 as certain overheads previously charged to CEMA are now included in the GRC.

82. ERDU was originally created to coordinate responses to inquiries related to the October 2017 Wildfires.

83. A slower ramp-up of the FAI project was experienced in prior years due to vendor delays. The vendor has been replaced and activity levels for 2018 and beyond are expected to be at intended levels.

84. PG&E is expected to act prudently with respect to the purchase of additional insurance using funds in excess of what is authorized in this decision.

85. PG&E should obtain additional insurance beyond its forecast if the market presents a reasonable opportunity to do so and if competitively-priced insurance is available.

86. PG&E's IGP and Grid Modernization Plan manages PG&E's electric distribution operating technology projects, which includes various system and infrastructure investments, upgrades, and enhancements such as SCADA and communications network associated with modernizing its electric grid.

87. Majority of IGP and Grid Modernization O&M costs reflect O&M costs for capital projects requested to enhance PG&E's IGP program and Grid Modernization Plan.

88. IGP and Grid Modernization costs are higher than recorded 2017 expenditures because most of the projects were expected to be finished in 2018 and 2019 and so no O&M costs were incurred in 2017.

89. Projects under EP&R include CWSP initiatives such as establishment of a WSOC in San Francisco, expanded weather station deployment, advanced fire modeling, enhanced wire down detection, technology base camp improvements to permit communication during catastrophes, early earthquake warning, and the project to build an emergency information sharing platform.

90. Approximately 200 weather stations were actually constructed in 2018.

91. Recent wildfires from 2017 onwards have increased in scale making it reasonable to forecast increased work and projects relating to EER.

92. Regarding DSO capital projects, the settling parties agree to reduce PG&E's 2020 revenue requirement by approximately $0.5 million each year to account for unit shortfalls for FLISR and cable installations.

93. Capital projects under EDM are for preventive maintenance such as replacing deteriorated facilities on a planned basis in cases where repair is not cost effective.

94. The Surge Arrester Replacement program combines the grounding of defective surge arresters with replacement of non-exempt surge arresters.

95. Grounding work is necessary pursuant to GO-95 but replacement of non-exempt surge arresters is not required and not one of the top risks identified in PG&E's 2017 RAMP Report.

96. While not identified as a top risk, replacement of non-exempt surge arresters serves to mitigate fire risk in HFTD and also non-HFTD areas.

97. The Non-Exempt Equipment Replacement program aims to replace non-exempt distribution line equipment with equipment exempt from vegetation clearing requirements of section 4292 of the Public Resources Code, which requires PG&E to maintain a firebreak within a certain radius from a utility pole.

98. Capital forecasts for Underground and Network Preventive Maintenance involve typical replacements of corroded transformers, inoperative switches, relay replacements, and other equipment in underground and network distribution facilities that are ordinarily conducted by PG&E.

99. PG&E's updated work plan includes 21,000 additional poles replacements (2020 to 2022) in addition to its original forecast of approximately 24,000 poles for that same period without a change in the proposed costs.

100. Capital projects under System Hardening and Reliability were expanded in 2019 and 2020 to include investments in the overhead distribution system to reduce risk of wildfire ignitions and circuit damage in the event of a wildfire.

101. Forecasted expenditures for Overhead System Hardening are significantly larger due to plans to expand the program to include large scale wildfire mitigation.

102. PG&E reduced its forecast for Overhead System Hardening from $817.039 million to $580.807 million, in part because of comments from parties, by shifting some costs to later years, by lengthening its time window target for system hardening from 10 to 14 years, and by shifting some of the system hardening budget towards undergrounding projects.

103. The settlement also adopts revenue requirement true-ups, reasonableness thresholds, reporting, and other requirements affecting overhead system hardening through CWSP guidelines.

104. Capital projects for Underground Asset Management such as cable replacement projects, cable rejuvenation testing, and various types of switch replacements are performed regularly by PG&E.

105. OSA recommended establishment of a dedicated program to inspect and remove certain types of antiquated oil-filled switches installed as early as the 1940s.

106. There are not many oil-filled switches left and PG&E schedules replacement of these antiquated switches whenever it discovers these types of switches through its regular inspections.

107. Substation Asset Management capital projects relating to substation work to replace various equipment, transformers, and emergency equipment and projects relating to safety and security of the substation location and perimeter are routinely conducted by PG&E and have been authorized in prior GRCs.

108. Operational Capacity capital projects are designed to increase distribution capacity in order to maintain customer load on a feeder at a maximum of 6,000 customers and to prevent issues from occurring as the number of customers increase.

109. The proposed Operational Capacity projects help ensure that there is sufficient capacity for the electric distribution system especially in times where load is unusually high such as during extreme weather conditions.

110. Remote access to capacitor banks provides greater flexibility to make setting changes and eliminates the need for field visits, increases operational

flexibility during planned and emergency switching, and improves the overall reliability of voltage throughout the system.

111. Proposed projects under Electric Distribution Technology involve technology upgrades and enhancements to support asset and work management functions and capital forecasts for 2018 to 2020 are significantly lower than recorded expenditures in 2017 by approximately $6.0 million or more due to prioritizing of capital projects in other areas.

112. The settlement adopts PG&E's forecast for New Business and WRO which was developed based on a number of economic and government spending indices as well as historical PG&E unit cost data.

113. PG&E's Rule 20A Program allows governmental agencies to underground existing overhead electric facilities if their projects meet specific criteria; and the capital projects under Rule 20A are for conversion of existing overhead electric distribution facilities to underground facilities.

114. PG&E reduced its Rule 20A capital forecasts for 2019 and 2020 following recommendations from Cal Advocates based on the average annual amount by which PG&E has underspent its authorized Rule 20A funding during the 10-year period of 2009 through 2018.

115. Purchase of capital tools[394] and equipment to replace general tools and for applied technology services is a routine activity regularly conducted by PG&E.

116. Savings from CWSP management offices capital, paid time off, indirect labor, material burden overheads, and affordability savings are reflected in Electric Distribution Support Activities Miscellaneous Capital.

[394] The total cost of Capital Tools is gradually amortized over a period of time instead of being recognized as an expense at the time of acquisition.

117. Electric Distribution Operations Technology projects relate to deployment and integration of a new ADMS and improvement of Distribution Asset GIS Data.

118. Expenditures in the prior GRC were prepared assuming that ADMS integration would begin in 2019, which means that 96 percent of ADMS costs were forecast to be incurred in this GRC cycle.

119. Capital projects under IGP and the Grid Modernization Plan support DER integration and connectivity to PG&E's system which means that some projects can be viewed as forward-looking projects that do not provide immediate benefits.

120. Concerns about IGP and the Grid Modernization Plan capital projects mostly relate to the scale of the project and timing for when the project should be undertaken.

121. The CWSP programs aggressively seek to mitigate wildfire risk by incorporating a risk-based approach to identify and address PG&E's assets that are most at risk from the threat of wildfires and its associated events.

122. The expanded mitigation activities and capital projects under CWSP are new and costs are difficult to predict.

123. Even PG&E admits that the scope and specifics for some CWSP-related programs and projects are still uncertain, especially those relating to system hardening.

124. A two-way balancing account to track CWSP costs allows PG&E to spend more than the authorized amount in cases where the authorized forecast is below what is necessary to conduct necessary and important safety-related mitigations against wildfire risks and allows return of funds to ratepayers if actual expenditures are lower than forecast.

125. The mechanism adopted in the Settlement for the WMBA affords the Commission a reasonableness review if expenditures exceed a certain level above the authorized forecast.

126. PG&E provides project summaries with costs for its CWSP projects in its workpapers and the 2020 forecasts are adequately supported by the record in the proceeding considering the current progress of PG&E's wildfire mitigation activities.

127. The increased scope of CWSP work planned for 2021 and 2022, especially for system hardening, may not be feasibly undertaken or completed as scheduled given the constraints that PG&E and other parties state in testimony and there is insufficient support for the unit cost forecasts for 2021 and 2022 for system hardening.

128. The capital forecast for CWSP projects in 2021 is more than 50 percent higher than the 2020 forecast while the 2022 capital forecast is almost double the costs forecasted for 2020.

129. Among other things, AB 1054 prohibits California's large electrical corporations from earning an equity return on their share of the first $5 billion of capital expenditures that the state's electrical corporations aggregately spend on fire risk mitigation measures approved in their wildfire mitigation plans. Each utility's share is determined by the Wildfire Fund allocation metric.

130. According to section 8386.3(e) of the Public Utilities Code, PG&E cannot earn an equity rate of return on its share of the first $5 billion of capital expenditures that the state's large electrical corporations aggregately spend on wildfire risk mitigation measures approved in their wildfire mitigation plans. PG&E's share, as determined by the Wildfire Fund allocation metric is 64.2 percent, or $3.21 billion.

131. In lieu of an equity return, PG&E is requesting to earn a debt return on CWSP capital expenditures in this GRC cycle.

132. Section 8386.3(e) allows PG&E to finance the GRC CWSP capital expenditures with a financing order pursuant to section 850.1 and Section 8386.3(e) allows debt financing for these wildfire mitigation capital expenditures.

133. Other capital expenditures subject to the section 8386.3(e) equity return exclusion are recorded in the WMPMA.

Energy Supply

134. Energy Supply costs are for work activities related to operating and maintaining PG&E's generation facilities and include PG&E's energy procurement administration costs, generation support costs, as well as costs for acquiring power to meet customer demands.

135. Energy Supply capital projects are for generation equipment, dams, and waterways, safety and regulatory projects, infrastructure, and other capital projects.

136. The settlement reduces PG&E's proposed forecast for Energy Supply O&M costs by $4.0 million. Specifically, the reduction is in PG&E's forecast for Energy Procurement Administration.

137. For Hydro Operations, costs for routine operations, maintenance, and compliance are primarily based on labor and other recurring costs which are typically consistent year over year.

138. PG&E's O&M forecast for Hydro Operations are based on 2017 costs plus escalation while projected FERC fees were based on average annual generation.

139. The capital forecast for Hydro Operations are for projects regarding maintenance of buildings, dams, roads, and other infrastructure necessary to operate PG&E's hydro generation system while other projects are to replace,

maintain, or install equipment and infrastructure in support of or necessary to operate or obtain licenses to operate the hydro systems.

140. It is difficult to accurately forecast the timing for issuance of FERC licenses associated with hydro generation and the required measures and conditions imposed for obtaining licenses vary.

141. Regulatory fees and work because of the Oroville spillway incident are necessary costs that will be incurred by PG&E.

142. Rehabilitation and repair of various facilities required by FERC for the Crane Valley Project have been delayed due to factors outside of PG&E's control and inclusion of these costs should be treated as an exception to the requirement that only licenses issued on or after January 1, 2012 should be included for recovery in the HLBA.

143. PG&E's O&M forecast for Natural Gas & Solar are based on 2017 costs for operating and maintaining its natural gas, PV solar, and fuel cell facilities plus escalation and other cost drivers, such as increased engine maintenance for Humboldt, solar warranty expirations in 2017, increased permit fees, and cost model changes.

144. The 10 reciprocating engines at Humboldt are not operated for an equal number of hours and so engine overhauls are based on run-hours and start-stops making it reasonable for engine overhauls to be on a staggered schedule based on hours of operation instead of average hours of operation for all engines.

145. LTSA costs in 2018 were unusually low.

146. Recorded costs under Maintain Alternative Generation Generating Equipment were low in 2018 because PG&E enforced a $0.255 million performance penalty against PG&E's contract service provider and the fourth quarter 2018 payment was paid in 2019 rather in 2018.

147. Proposed capital projects under Natural Gas & Solar are necessary to operate and maintain PG&E's natural gas, PV solar, and fuel cell facilities.

148. Leveling costs associated with major LTSA outages at the Gateway and Colusa facilities are consistent with the requirement of D.17-05-013 to spread out periodic LTSA costs.

149. The settlement applies a $4.0 million reduction to the adjusted forecast for Electric Procurement Administration in the interest of customer affordability.

150. Costs for Technology Programs are necessary to upgrade and maintain the IT systems and technology associated with electric generation and electric and gas procurement.

151. The O&M forecast for Nuclear Operations is reflective of affordability initiatives, outage optimization, and implementation of various projects that reduce the need for security compensatory measures.

152. PG&E states that all regulatory improvement actions regarding DCCP have been completed in compliance with state and federal regulations to ensure that a core damaging event is effectively managed with minimal risk.

153. The Stator Replacement Project is based on an extensive inspection and evaluation of the Unit 2 main turbine generator conducted by the manufacturer wherein it was revealed that progressive degradation of certain components will likely lead to the eventual failure of the generator stator which in turn could lead to an unplanned outage of 100 days or more.

154. Failure of the main turbine generator increases safety risks associated with a potential hydrogen fire at the plant.

155. Reduction of the decommissioning reserve for PG&E's generation assets (fossil, fuel cells, hydroelectric, and solar) is appropriate to incorporate the impact of the sales of the Deer Creek and Narrows facilities.

156. Decommissioning costs for Diablo Canyon and Humboldt Bay nuclear decommissioning trusts are part of PG&E's Nuclear Decommissioning Cost Triennial Proceeding application pursuant to D.03-10-014.

157. The amount of the decommissioning reserve is based on the assets that PG&E currently has and it is not reasonable to assume that assets will be sold absent more concrete evidence.

158. The decommissioning reserve should be reviewed in PG&E's next GRC cycle to determine what adjustments are needed to the decommissioning reserve amount.

159. The claims procedure for Spent Nuclear Proceeds funds is part of the settlement to reimburse PG&E for the costs of storing spent nuclear fuel at DCPP and Humboldt Bay.

160. Recovery of direct costs for DCCP cancelled projects recorded as of June 30, 2016 was authorized in the DCCP retirement decision.

161. LTSP costs were transferred to the DCSSBA as part of the process regarding integration of the AB 32 advanced seismic studies with the SSHAC.

162. Integration of AB 32 advanced seismic studies is now complete and additional costs are not expected.

163. Recovery of expected end of plant materials and supplies is reasonable because it is necessary to retain a certain level of inventory to support the DCPP's continued operation until 2024 and 2025.

164. The settling parties agree that ISFSI costs should be treated as expense rather than capital costs for purposes of this GRC.

165. The settlement was amended to remove ISFSI capital costs from the 2020 capital forecast.

Customer Care

166. For its Customer Care operations, PG&E requests TY2020 forecasts of $316.435 million in expenses and $141.7 million in capital expenditures.

167. For PG&E's Customer Care operations, the settlement adopts a TY2020 forecast of $277.5 million in expenses, which represents a $35 million reduction from PG&E's original forecast, and $140.2 million in capital expenditures.

168. The settlement agreement adopts PG&E's forecasted expenses and capital expenditures for the activities related to Customer Engagement, as well as a stipulation between PG&E and TURN to revise PG&E's forecast for AB 802 compliance expenses.

169. The settlement adopts PG&E's proposed cost recovery and account treatment for the AB 802 memorandum accounts, including the disposition of costs recorded in the accounts, the amortization period of the costs, and the closure of the accounts.

170. PG&E's proposed amortization period for the AB 802 memorandum accounts is estimated to cause a small rate impact, and is similar to the amortization periods used for other comparable PG&E memorandum accounts.

171. The costs recorded in the AB 802 memorandum accounts are costs PG&E incurred to accomplish the goals of AB 802.

172. The settlement adopts the MOU between PG&E and SBUA, as well as PG&E's proposed cost recovery mechanism for the costs PG&E commits to spend in the MOU.

173. The MOU between PG&E and SBUA promotes the collaboration between PG&E and its small and medium business customers.

174. The settlement agreement adopts PG&E's unopposed forecasted expenses for the Income Qualified Programs.

175. The settlement adopts a stipulation between TURN and PG&E pertaining to the forecasts for non-residential rates implementation activities and for the Natural Gas Appliance Testing program.

176. PG&E considers varying labor rates in different regions, time to install, and material costs when deriving its forecast for the Natural Gas Appliance Testing program.

177. For the recovery of residential rate reform costs, the settlement proposes to allow PG&E to first collect in rates the forecasted costs of the rate reform implementation and Statewide ME&O activities, while recording the actual costs in the Residential Rate Reform Memorandum Account (RRRMA), and true-up the revenue collected in rates for the rate reform and Statewide ME&O activities with the costs recorded in the RRRMA during a reasonableness review at the end of the GRC cycle.

178. The settlement's proposed treatment of residential rate reform costs protects the interests of both ratepayers and shareholders in that ratepayers will pay PG&E only for the actual costs of the activities, which costs PG&E must demonstrate are reasonably incurred, while shareholders do not have to advance the entire costs of the residential rate reform activities for a three-year GRC cycle.

179. The settlement adopts PG&E's forecasts for the Contact Centers Operations (CCOs), which, other than the costs for the Salesforce Phase 2 and Phase 3 projects, were not contested by the parties.

180. The settlement adopts a stipulation between TURN and PG&E in which the parties agreed on a revised project timeline and revised forecasted expenses and capital expenditures for the Salesforce Phase 2 and Phase 3 projects.

181. Other than PG&E's proposed closure of Customer Services Offices (CSOs), the settlement adopts PG&E's unopposed forecasts and proposals for the CSOs' operations.

182. The settlement adopts PG&E's MOU with CforAT to improve customer accessibility to PG&E services at the CSOs and at other PG&E facilities, as well as PG&E's proposed recovery of costs for the MOU.

183. The settlement proposes that PG&E file a Tier 1 advice letter to close 10 of the 17 CSOs PG&E originally proposed to close.

184. The settlement did not indicate which CSOs PG&E will close and the criteria PG&E will consider in selecting the CSO for closure.

185. Without knowing the exact CSOs PG&E will close, the Commission cannot assess how much impact a CSO closure would have on the 5% of people who cannot perform utility transactions other than in person, particularly since a majority of CSO users are low income.

186. In D.98-07-077, the Commission directed Southern California Edison to provide notices to customers prior to closing any customer service office.

187. The settlement adopts PG&E's forecasts for the Metering program, in which only the metering reading expense was disputed initially.

188. PG&E's forecast for the metering reading expenses considers the reduced number of meter reads, the increasing average costs of meter reads, and escalation increases due to inflation.

189. The settlement reduces PG&E's forecast related to collection and payment processing activities by $1.2 million in the interest of customer affordability.

190. Other than the forecast for collection and payment processing activities, the settlement adopts PG&E's forecasted expenses and proposals for activities

supporting the Billing, Revenue, and Credit operation, which were not contested by the parties.

191. The settlement adopts PG&E's unopposed proposed fee reductions for its service reconnection service and non-sufficient funds (NSF) check returns.

192. Based on PG&E's forecasts of volume and cost for remote and field connections, PG&E proposes to lower its service reconnection fees, from $17.50 for non-CARE customers and $11.25 for CARE customers to $15.75 (a 10 percent decrease) for non-CARE customers and $10.25 (a 9 percent decrease) for CARE customers.

193. Based on PG&E's analysis of a reduction in total labor costs, notice generation costs, working capital costs, and fees charged to PG&E by the banks that process the customer payments, PG&E proposes to reduce its NSF fee from $7.00 to $4.60, which is a 34 percent decrease, in 2020.

194. The settlement adopts PG&E's unopposed 2020 forecast of an uncollectible factor of 0.003263, which PG&E forecasts using a rolling 10-year average, the same methodology it previously used.

195. PG&E's analysis of residential bill and disconnection data for the 2010-2017 period shows that the correlation between residential bills and the volume of nonpayment disconnections is none-to-weak for non-CARE customers but is moderate-to-high for CARE customers.

196. The settlement agreement reflects compromises that settling parties made in the interest of customer affordability.

197. The settling parties agreed on a $19.5 million reduction to PG&E's originally forecasted expenses in the areas of Energy Supply, Customer Care, Shared Serves and Information Technology, and Human Resources for the purpose of customer affordability.

198. The revenue requirement proposed in the settlement agreement results in a 3.4 percent increase of gas and electric bills in 2020.

199. D.20-06-003 put an annual cap on the percentage of residential customer accounts that PG&E can disconnect from utility service at four percent for 2020, 2021, and 2022.

200. Pursuant to Resolution M-4842, the Commission currently has a moratorium on utility disconnections because of the novel coronavirus, COVID-19, pandemic.

201. Because of the current moratorium on disconnections due to the novel coronavirus, COVID-19, pandemic, the revenue requirement approved in this proceeding will not have any immediate impacts on residential customer disconnections for non-payment.

202. D.20-06-003, which is effective June 11, 2020, prohibits PG&E from collecting customer deposits.

203. The settlement reduces PG&E's forecast for supervisory and management costs for the Customer Care organization by $2.8 million in the interest of customer affordability.

204. Other than the forecast for Customer Care supervisory and management costs, the settlement adopts PG&E's forecasted expenses for activities presented in the Regulatory Policy and Compliance section, which were not contested by the parties.

Shared Services

205. Shared Services generally provide company-wide support to PG&E's LOBs.

206. The settlement adopts an O&M forecast for Shared Services that is approximately $4.9 million less than PG&E's adjusted forecast. Specifically, the

reduction is with respect to PG&E's forecast for Real Estate Facilities Management.

207. As discussed in the Shared Services chapter, the amounts adopted by the settlement for Safety and Health, Materials, Sourcing, Land and Environment Management, and ERIM are reasonable. Most of the costs proposed for these departments are for activities that PG&E already performs.

208. The increase in costs for Transportation Services Expenses under TAS is largely due to a change in the cost model for TAS O&M and capital costs.

209. Transportation Services Expenses were largely impacted by storm and wildfire support costs in 2017.

210. Higher allocations for capital and balancing account expenditures in 2017 for storm and wildfire support resulted in less costs being allocated for Transportation Services Expenses O&M expenditures.

211. Although storm and wildfire costs are still included in the TY2020 forecast for Transportation Services Expenses, the forecast amount does not anticipate the unusually high levels of incidents that occurred during 2017.

212. PG&E will no longer apply Fleet Overhead Credits to GRC balancing accounts and is changing the way it calculates Overhead Credit for catastrophic events beginning in TY2020. This change aims to remove the impact of storm and wildfire unpredictability.

213. The change in the way PG&E calculates Overhead Credit for catastrophic events aims to remove the impact of storm and wildfire unpredictability with respect to expenditures for Transportation Services Expenses.

214. The amount of Overhead Credit for this GRC cycle is not expected to be as high as Cal Advocates originally proposed.

215. Increased O&M costs are anticipated for helicopter and aircraft maintenance, including additional costs for the four new firefighting helicopters that PG&E will purchase.

216. Historical costs for Real Estate expenditures from 2013 to 2017 have generally been decreasing although not at the level experienced from 2017 to 2018.

217. Although use of historical data is meant to account for an anomalous year, PG&E was not able to refute that the downward trend in CRESS expenditures will continue.

218. Companywide Expenses under Shared Services include costs for Long-Term Disability, Workers Compensation, DOT Drug Testing, EAP, and the Wellness Program

219. The programs that incur company-wide expenses under Shared Services are either mandated by law or are standard programs and benefits offered to employees by companies such as PG&E.

220. As discussed in the Shared Services chapter, capital projects for Safety and Health, Materials, Land and Environment Management, and ERIM are those that were routinely requested in past GRCs and are reasonable.

221. The capital forecasts for TAS includes costs to repower the four helicopters that PG&E intends to purchase with new engines as well as necessary costs to retrofit them into firefighting and construction helicopters.

222. Parties do not take issue with the necessity and planned use of the above helicopters for firefighting and construction.

223. PG&E already has an exclusive use contract with CALFIRE for two firefighting helicopters that have similar capabilities to the four that PG&E intends to purchase.

224. PG&E presented detailed testimony comparing the relative merits and the cost and benefits between owning and renting the four firefighting helicopters.

225. No clear evidence was provided to support the argument that more firefighting helicopters may be available for lease because of need and market conditions.

226. Helicopters are subject to regular maintenance and having a single helicopter means that it may not be available during an emergency situation.

227. Acquisition of the four firefighting helicopters enables PG&E to have exclusive access to four helicopters for firefighting purposes instead of the two it currently shares with CAL FIRE under an exclusive lease contract.

228. PG&E owning its own helicopters means not depriving CAL FIRE of any helicopters needed by it for emergency use and that more helicopters will be available for emergency and firefighting purposes, not only for PG&E, but also for CAL FIRE, which improves the state's ability to respond to and mitigate the threat of wildfires.

229. The PTY method adopted in the Settlement Agreement uses the general method originally proposed by PG&E of applying escalation to determine O&M costs and basing capital revenue requirement growth on plant additions.

230. To reduce TAS costs, PG&E does not plan on adding new vehicles to its existing fleet and has also extended its asset class lifecycles for this GRC cycle by two years.

231. Year-over-year Real Estate capital expenditures from 2013 to 2017 appear to be increasing and this trend continues in 2018 where recorded capital costs increased.

232. Several capital projects under Real Estate address safety and compliance such as repairing cracks, repairing deteriorating building conditions,

comprehensive restoration, and other similar projects needed to remediate safety and compliance concerns.

233. The settlement acknowledges TURN's proposed reduction for IT and Cyber security and in Article 2.6.2.3 applies a reduction of $6.5 million to promote customer affordability.

234. Projected increases in IT O&M costs are in large part due to the following: (a) new investments in cross-functional software applications and mobile technology necessary for PG&E's field workers; (b) new investments in software to support automation of certain processes aimed at improving efficiency, and (c) new investments to address long-term IT cost effectiveness, maintenance of asset security and reliability, to meet infrastructure demand, and to address new business technology capabilities.

235. Projected increases in Cyber security O&M costs can be attributed to project implementation costs to address increased risks concerning cyber and physical security as well as management and prevention of these risks.

236. The IGP IT Infrastructure Program consists of four workstreams: the FAN project; the SCADA Network Reliability Improvements; deployment of a substation Converged Platform; and the Data Center & Control Center Infrastructure Preparation.

237. IT projects are generally aimed at sustaining or improving technology, reliability, and security while other projects increase IT efficiency, enable new enterprise capabilities, and provide digital innovation.

238. The funding adopted by the Settlement Agreement for the FAN project considers the full scope and technology involved in the project and the fact that it is important to have control of communications network assets that support

critical operations because third-party networks are not always able to meet utility-specific requirements.

HR and IT

239. The main functions of HR are to conduct workforce planning, ensure competitive compensation and benefits, oversee hiring and selection, engage and assess the employees' attitudes towards safety, and provide employees with developmental and training opportunities.

240. PG&E's HR Organization consists of four departments namely, HR Operations, HR Services, Total Rewards, and PG&E Academy.

241. Department Costs are costs attributable solely to one of the four HR departments while Companywide Expenses are costs which benefit the entire company as a whole.

242. IT costs under HR are IT expenses that are attributable to the HR organization only.

243. Each of the four HR departments incur Department Costs, Companywide Expenses, and if applicable, IT costs.

244. As discussed in the HR chapter, the settlement reduces PG&E's adjusted O&M forecast by $90.973 million representing reductions of $1.203 million in Department Costs, $88.0 million in STIP costs, and $1.973 million in medical costs. The above reductions are exclusive of labor escalation adjustments also agreed-upon in the Settlement Agreement.

245. The $1.203 million reduction for Department costs reflects affordability considerations.

246. The settling parties adopted labor escalation rates for various employee classes for this GRC period as shown in Article 2.73 Table 5 of the Settlement Agreement.

247. Labor escalation rates reflect projected increases in costs for labor.

248. The agreed-upon labor escalation rates for 2020 to 2022 result in adjustments to PG&E's forecasts that include labor-related costs such as salaries.

249. The adjustments from the agreed-upon labor escalation rates in the settlement reflect a downward adjustment as compared to PG&E's labor escalation forecasts.

250. Department Costs have been relatively flat for the last five years.

251. Costs for PG&E's Total Compensation Study are amortized into the proposed forecast for Department Costs.

252. The $13 million revenue requirement reduction specified in Article 3.1 of the Settlement Agreement for forecast updates, concessions, and errata reflects adjustments that are included in PG&E's Joint Comparison Exhibits and is already incorporated into the Settlement Agreement.

253. HR costs in 2017 were unusually high but a five-year average is meant to take into account these types of fluctuations.

254. Cal Advocates originally proposed utilizing a four-year average but there was insufficient evidence demonstrating why the base year value should simply be discarded from the average.

255. Discussion of Companywide Expenses in the decision focuses on the expenses themselves and not the HR departments where the expenses are assigned.

256. The settlement reduces the STIP forecast by $88.0 million which is approximately 50.72 percent less than PG&E's forecast.

257. The metrics that comprise STIP regularly change and the Commission has imposed reductions to STIP forecasts when it has determined that particular

STIP programs benefit both ratepayers and shareholders such as in PG&E's 2014 and 2017 GRCs.

258. In D.19-09-051, the Commission examined the metrics for STIP and excluded those that it found benefitted shareholders.

259. The structure of the STIP program in this GRC shows that it provides benefits to both ratepayers and shareholders.

260. Actual STIP awards in 2016, 2017, and 2018 reflect the STIP forecast in PG&E's prior GRC and not this GRC.

261. The STIP forecast for TY2020 is a forward-looking forecast and recorded costs may not always equal what was forecast but the STIP forecasts were reviewed based on the available record in this proceeding.

262. Other than the reduction to STIP costs, the only other reduction in Companywide Expenses proposed in the settlement is a reduction of $1.973 million in Health and Welfare Benefits.

263. IT expenses support technology projects that support the HR department such as increased automation of employee-related processes and technology enhancements for the HR system.

264. Most of the proposed IT capital projects fall under Built IT Apps and Infrastructure which are projects for enhancements and upgrades to existing systems or additions that will enhance or expand existing capabilities to systems used by the HR Organization.

Administrative and General

265. A&G costs are expenses of a general nature not directly chargeable to any specific utility function and include general office labor, supply expenses, insurance, casualty payments, consultant fees, employee benefits, regulatory expenses, association dues, and stock and bond expenses.

266. A&G costs are divided by type of costs: Department Costs, Companywide Expenses, or IT Costs.

267. The Settlement Agreement reduces PG&E's O&M forecast for A&G by $71.681 million.

268. O&M costs reflect the total gross company amount as opposed to the GRC net amount and certain cost items include cost components for other Commission proceedings, FERC proceedings, and separately-funded items.

269. An allocation factor of approximately 83.09 percent is applied to determine the GRC net amount.

270. The allocation factor is based on 2017 recorded adjusted O&M labor which parties do not oppose.

271. The settlement adopts PG&E's forecasts for Risk and Audit, Compliance and Ethics, Law Organization, and Corporation, Executive Offices, and Corporate Secretary less small reductions representing labor escalation adjustments adopted by the settlement. The forecasts are lower than base year expenditures and reflect the downward trend in expenditures over the last five years.

272. The Settlement Agreement proposes reductions to Finance, Regulatory Affairs, and Corporate Affairs of $10.899 million, $0.242 million, and $0.362 million respectively inclusive of labor escalation adjustments also adopted by the settlement.

273. The reduced forecast for the Finance Department is due to labor savings from staffing reductions, reductions in business finance contracts and outside services, and implementation of affordability initiatives.

274. The reduced forecast for Regulatory Affairs reflects lower expenditures in 2017 and adequately addresses concerns regarding increased costs for the VP office.

275. The reduced forecast for Corporate Affairs reflects the reduction in staffing levels due to reorganization and elimination of redundancy.

276. Companywide Expenses under A&G are for costs incurred which benefit the entire company such as insurance premiums, settlements and judgments, fees, and other similar costs.

277. The forecast methodologies utilized and settlement amounts for Bank Fees, Third-party Claims, and Director Fees and Expenses are reasonable.

278. A forecast based on a four-year average for Third Party Claims is reasonable because of fluctuating costs.

279. Costs for Bank Fees and Director Fees and Expenses are expected to remain the same.

280. Renewal costs for General Liability insurance have increased significantly in 2018.

281. The forecast for Non-nuclear property insurance is higher than base year expenses because of expanded coverage for earthquake risk.

282. The forecast for Other Property insurance is reasonably higher than 2017 expenditures.

283. The forecast for Nuclear Property insurance is less than 2017 expenditures by approximately 38 percent because of deductibles in PG&E's insurance premium.

284. Consistent with D.14-08-032, PG&E only included 50 percent of its total costs for Director and Officers Liability insurance.

285. The settlement proposes a reduction of $60.173 million to PG&E's forecast for General Liability insurance.

286. General Liability insurance coverage for $818 million cost $124 million in 2017 but coverage for $1.4 billion in 2018 cost $360 million.

287. PG&E's forecast considers market insights, continued exposure to wildfire risk and California's application of inverse condemnation law with respect to damage from wildfires. Insurance costs also cover instances wherein PG&E might have acted negligently.

288. Insurance costs for General Liability coverage has been difficult to predict in recent times because of market conditions and the recent wildfires in California.

289. A two-way balancing account for General Liability insurance costs will help ensure that there is adequate insurance coverage and allows PG&E to act in a timely manner.

290. Tier 2 Advice Letter review of additional insurance expenditures allows the Commission to review other types and levels of coverage not presented in this GRC and addresses PG&E's need to act quickly where it finds need to purchase additional insurance

291. The record shows that PG&E intends to purchase insurance prudently and seeks to avoid insurance that costs more than 50 percent of the coverage provided.

292. Amounts invested into the reinsurance fund will come from amounts authorized in this GRC and recovery of any excess funds invested shall be subject to Commission review.

293. The costs tracked in the WEMA represent actual incremental wildfire-related costs that were incurred from July 26, 2017 to August 1, 2018 in excess of the amounts included in rates.

294. Authorized costs from PG&E's 2017 GRC were based on 2014 recorded costs and wildfire-related insurance costs have gone up since 2014.

295. IT projects under A&G are for support technology enhancements that routinely maintain the technology systems of the departments under A&G and costs incurred are in connection with regular IT upgrades that are undertaken to update and enhance various IT-related technology and support systems.

296. Most of the proposed IT capital projects under A&G are for enhancements and upgrades to existing systems that increase or enhance existing capabilities or consolidate related functions.

Results of Operations

297. The forecasted revenue requirement is calculated through a computer model, called the Results of Operations (RO) model.

298. The major components of the RO model are Rate Base, Taxes, Other Operating Revenues, and Cost Allocation Factors.

299. PG&E's Rate Base is the value of the assets PG&E owns and uses to provide utility service, less the depreciated value of the assets.

300. PG&E earns a return on the capital investments recorded in Rate Base.

301. The Rate Base is comprised of Utility Plant, Working Capital, Customer Advances, Customer Deposits, and Depreciation Reserve.

302. Utility Plant is the value of undepreciated assets that PG&E uses to provide service, which is comprised of the assets that are currently used and useful in providing utility service to customers and the capital investments PG&E is authorized to add to its plant.

303. Working Capital is comprised of Working Cash and Materials and Supplies costs.

304. Working Cash is composed of working cash required for day-to-day operations and cash needed to pay operating expenses in advance of receiving payments from customers.

305. The elements of working cash are (a) Special Deposits and Working Funds, (b) Other Receivables, (c) Prepayments, (d) Deferred Debits, (e) Goods Delivered to Construction Sites, (f) Accrued Vacation, and (g) Cash Required due to Time Lags.

306. Special deposits include deposits with federal, state, or municipal authorities to ensure that PG&E can fulfill its obligations.

307. Working funds include the petty cash PG&E uses to make change for customers who make cash payments at the local offices.

308. The settlement adopts PG&E's unopposed forecasts for Special Deposits and Working Funds, which are derived using the average of recent recorded data and adjusted for inflation.

309. Other Receivables are non-interest-bearing accounts that are not part of the revenue that would affect the revenue lag, such as non-energy billings like main-line extensions, paid insurance claims, and non-recurring receivables.

310. The settlement adopts a $23 million revenue requirement reduction to PG&E's forecast for Other Receivables.

311. Cal Advocates and TURN recommended removing non-recurring expenses items from Other Receivables, arguing that Working Cash is for funds that are permanently committed to financing the lag between operating expenses and the receipt of revenues, and should thus be forecasted based on permanent

commitments rather than non-recurring one-time commitments made during the recorded base year.

312. There are non-recurring receivables that occur in any given year, even though the amount and nature of non-recurring receivables differ from year to year.

313. Prepayments are the amount of capital required from investors to pay for insurance premiums, software license fees, taxes, and other goods and services in advance of the coverage or service period.

314. The settlement adopts PG&E's unopposed forecast of Prepayments.

315. Deferred debits are the expenses that are in the process of amortization, clearing account amounts, and unusual expenses that are not included in other current asset accounts.

316. The settlement adopts PG&E's proposed forecasts and proposals for Deferred debits.

317. PG&E calculates its forecasts for Deferred debits using the average of 12 month-end balances of the 2017 recorded year, adjusted for inflation with A&G escalation rates.

318. Goods Delivered to Construction Sites is the cost of contractor-supplied goods delivered to a construction jobsite and is deducted from working cash capital as part of Construction Work In Progress (CWIP).

319. PG&E forecasts Goods Delivered to Construction Sites using the recorded data from the base year, 2017, following guidance from Standard Practice U-16 of using the base year.

320. The settlement adopts PG&E's forecasted deductions for Goods Delivered to Construction Sites.

321. Accrued vacation, which is the amount accrued through operating expenses for future liabilities which the utility has available until payments to employees for vacation are made, is deducted from the operational cash requirement.

322. The settlement adopts PG&E's unopposed forecast for accrued vacation.

323. Working cash not supplied by investors is a deduction to working cash and includes items such as certain tax collections payable and employee withholdings for medical, dental, and vision plans.

324. The settlement adopts PG&E's unopposed forecast for working cash not supplied by investors.

325. Cash required due to time lags is the amount of working cash required to pay expenses in advance of the receipt of revenues, and is calculated by weighting the utility's expense lags into an overall average and subtracting this amount from the calculated revenue lag.

326. PG&E's forecasting methodology for the revenue lag is based on the guidance of Standard Practice U-4 by using the base year recorded data as the forecast.

327. Cal Advocates and TURN proposed adjusting the revenue lag to account for the timing difference of when the greenhouse gas climate credit refunds are recognized.

328. The settlement adopts a revenue requirement reduction of $10 million for adjustments to the revenue lag, which effectively adopts Cal Advocates' and TURN's recommended adjustments to recognize the return of greenhouse gas climate credit at the time when customer bills are generated.

329. Materials and Supplies Capital costs are for tools and equipment that support PG&E's maintenance and construction activities.

330. PG&E proposes to include its greenhouse gas compliance instrument inventory costs as part of its Working Capital forecast.

331. Cal Advocates recommends removing the carrying costs of greenhouse gas compliance from the Working Capital forecast and proposes that PG&E recover these costs in the ERRA proceedings instead, because the Commission reviews the reasonableness of PG&E's greenhouse gas compliance instruments costs in ERRA proceedings.

332. The settlement adopts a $26 million reduction in revenue requirement for the removal of the carrying costs of greenhouse gas compliance from the Working Capital forecast and proposes that PG&E recovers these costs in the ERRA proceeding or Annual Gas True up advice letters.

333. Customer Advances are the monies PG&E collects from new customers connecting to utility services and are a reduction to Rate Base.

334. The settlement adopts PG&E's unopposed forecast for Customer Advances.

335. Customer Deposits are monies PG&E collects from customers who do not have good financial credit or who have been disconnected for non-payment.

336. The settlement proposes to continue the ratemaking treatment granted in D.19-12-056 (PG&E's 2020 Cost of Capital decision) for Customer Deposits.

337. PG&E's 2020 Cost of Capital decision sufficiently addressed the ratemaking treatment for Customer Deposits.

338. Depreciation Reserve is the total amount of depreciation, in terms of dollars, that has accumulated from the assets that are in Utility Plant.

339. Depreciation Expenses allow the utility to recover the capital costs of fixed assets, less net salvage value, plus removal costs, in equal installments over the estimated remaining service life of the assets.

340. PG&E's annual depreciation expenses are determined by depreciation parameters, which are net salvage value, removal costs, and estimated service lives.

341. PG&E, Cal Advocates, and TURN reached a stipulation to retain the depreciation rates and depreciation parameters from D.17-05-013 (PG&E's 2017 GRC Decision) for this GRC.

342. The settlement agreement modifies some of the depreciation parameters adopted by the stipulation and will result in a $150 million revenue requirement reduction for PG&E's depreciation expenses.

343. Since the last GRC, there have been no major factors changing the appropriateness of using the 2017 depreciation parameters to set depreciation expenses.

344. Adopting the 2017 depreciation parameters, which include the average service lives, survivor curves, and net salvage percentages, for calculating depreciation expenses, will continue to provide intergenerational equity for ratepayers.

345. The settlement modifies some of the net salvage percentages that were adopted by the initial stipulation.

346. The net salvage percentages adopted by the settlement represent a compromise of the parties' initially disputed positions and are supported by the record as within the range of reasonable outcomes.

347. PG&E's forecasted tax expenses are comprised of corporate income taxes, property taxes, payroll taxes, and taxes other than income and property that PG&E will incur from providing gas and electric services.

348. PG&E's forecasted tax expenses and proposed method of calculating tax expenses are uncontested.

349. The settlement proposes to modify the Tax Memorandum Account (TMA) so that it only records any net revenue changes due to mandatory and elective tax law changes, tax accounting changes, tax procedural changes, or tax policy changes.

350. The settlement's proposed modifications to the TMA remove PG&E's burden of recording all differences in estimated and recorded income taxes, since there are inherently many factors that cause these differences, and these factors are also difficult to isolate and identify, and addresses Cal Advocates' concerns for a transparent process to track any changes to income taxes due to mandatory or elective tax law, tax guidance, tax policy, or tax accounting changes.

351. Accumulated Deferred Income Taxes (ADIT) result from the timing differences between book depreciation used for ratemaking purposes and tax depreciation used for tax purposes.

352. The settlement proposes that PG&E file an advice letter to correctly reflect the return of excess ADIT created by the passage of the 2017 Tax Act, which reduced PG&E's federal corporate income tax rate from 35% to 21%.

353. Other Operating Revenues (OOR) are revenues PG&E receives that are not directly generated from rates, but are related to its generation, distribution, or sale of electric energy or natural gas activities, and come from items such as rent from electric and gas properties, field collection, reconnection fees and return-to-maker check charges, recreational facilities and timber sale receipts, sales of water for power, transmission wheeling service fees, revenues reimbursing PG&E for work performed for other entities, and other miscellaneous service revenues.

354. PG&E forecasts OORs based on expected future activities and events, using an item-by-item forecasting method, which can forecast OORs with reasonable certainty.

355. The settlement adopts PG&E's forecast and forecasting methodology for OORs.

356. PG&E allocates the operational and capital costs it requests to recover in this GRC into three major utility functions (electric generation, electric distribution, and gas distribution) in a process which we refer to as the "functionalization" of costs, or PG&E's cost allocation methodology.

357. The Commission has adopted the principle of cost causation, which is the policy of allocating costs to the group of customers that incurs the costs.

358. Common costs, which are costs associated with common plants, are allocated across all of PG&E's major utility functions, because they share usage of the same common plants.

359. There are certain CWSP costs that PG&E incurred to support wildfire mitigation efforts that benefit all utility functions. These costs include situation awareness program costs, CWSP program support costs, and costs of CWSP activities performed by its emergency, preparedness, and responses organization, and the costs of the heavy-lift helicopters.

360. The settling parties and the JCCAs agree that CWSP costs that PG&E incurs to support wildfire mitigation efforts that benefit all utility functions should be allocated as common costs.

361. The settling parties agree to allocate Locate and Mark costs 33.3 percent to electric distribution and 66.7 percent to gas distribution.

362. The majority of Locate and Mark activities pertain to PG&E's gas distribution function, while the rest of the Locate and Mark activities support the electric distribution function.

363. The settling parties agree to treat the excess liability insurance costs as a common cost expense, as PG&E proposed, which would allocate the costs 37 percent to electric distribution, 22 percent to gas distribution, 24 percent to electric generation, 6 percent to electric transmission, and 11 percent to gas transmission

364. PG&E purchases the excess liability insurance to provide coverage for all of PG&E's lines of business.

365. The settling parties propose to allocate 100 percent of Pricing Products and Income Qualified rate programs that pertain only to electric customers to the electric distribution function.

366. The settlement's proposal to allocate 100 percent of Pricing Products and Income Qualified rate programs costs, which pertain only to electric customers, to the electric distribution function, aligns with the Commission's policy of allocating costs to the set of customers on whose behalf the costs were incurred.

367. MWC EV, which includes the costs of work associated with processing applications of new gas and electric customers and work associated with helping existing customers add load to or rearrange their services, and MAT EVA, which includes costs that support new gas and electric services, are costs PG&E incurs to support both electric and gas distribution functions.

368. The settlement functionalizes the MWC EV and MAT EVA costs based on the number of electric and gas service agreements, which results in allocating 55 percent of the costs to the electric distribution function and 45 percent of the costs to the gas distribution function.

369. There are certain CWSP programs that directly support electric distribution assets. These CWSP programs include System Hardening and Enhanced Vegetation Management, Enhanced Operational Practices (Reclose Blocking costs and Supervisory Control and Data Acquisition programming to support Reclose Blocking), and Automation and Protection Enhanced Operation Practices (fuse savers, granular sectionalizing, and Resilience Zones).

370. The Resilience Zones program directly supports PG&E's electric distribution infrastructure and benefits all distribution customers.

371. The Resilience Zones benefit all distribution customers by providing temporary power to customers that would otherwise experience outages due to a Public Safety Power Shutoff (PSPS) event, and benefit both bundled and unbundled customers equally.

372. Grid modernization improves cybersecurity, reliability, safety, and integration and management of distributed energy resources into the grid.

373. Grid modernization directly supports PG&E's electric distribution infrastructure and benefits all distribution customers.

374. Bundled and unbundled customers share the benefits of grid modernization.

375. PG&E is incurring grid modernization costs on behalf of its distribution customers.

376. PG&E currently allocates the customer care costs between its electric distribution and gas distribution functions, based on the number of electrical and gas service agreements, resulting in an allocation of 55 percent of the costs to electric distribution and 45 percent of the costs to gas distribution.

377. PG&E incurs customer care costs on behalf of both bundled and unbundled electric customers.

378. The record is unclear as to whether generation customers use more or less customer care services than gas or electric distribution customers, or cause PG&E to incur more or less customer care costs than gas or electric distribution customers.

379. The record data does not allow us to extrapolate the extent of customer service usage by generation customers relative to gas or electric distribution customers, or the extent of costs generation customers impose on customer care services compared to gas or electric distribution customers

380. The record shows that many of the customer care services support distribution issues that affect both bundled and unbundled customers equally in that both bundled and unbundled electric customers need customer support on issues related to system reliability, service planning, demand-side management programs, billing, payments, start, stop or transfer services, outages, gas leaks, and emergencies.

381. PG&E currently does not track data that allow us to confidently extrapolate the extent of customer service usage by generation customers relative to gas or electric distribution customers, or the extent of costs generation customers impose on customer care services compared to gas or electric distribution customers.

382. An appropriate functionalization methodology is important to ensure that costs are appropriately allocated to PG&E's electric generation function, which only bundled customers pay, and electric distribution function, which both bundled and unbundled customers pay, and to prevent possible cost subsidies between the bundled and unbundled customers.

383. Without an appropriate cost functionalization process, costs may be misappropriated between electric generation and distribution functions, possibly causing cost shifts between bundled and unbundled customers.

Other Adjustments and Terms / PTY

384. The Settlement Agreement adopts 2018 capital forecasts but pursuant to Article 3.2 requires that these be adjusted and replaced with recorded capital costs for 2018.

385. PG&E's 2018 recorded capital expenditures reflect actual costs incurred during 2018 and in this case are more accurate that PG&E's 2018 capital forecasts.

386. The deferred work principles specified in Article 5.2 of the Settlement address and balance PG&E's need to re-prioritize and reallocate funding for resources when appropriate but at the same time address a concern raised by TURN that funding for work not performed had already been authorized and whether such work is necessary.

387. The settling parties' agreement that PG&E's risk showing in its next GRC comply with the settlement agreement in D.18-12-014 resolves issues raised by TURN and Cal Advocates regarding RAMP integration in this GRC.

388. Resolution WSD-002 on June 11, 2020 states, among other things, that RSE is not an appropriate tool for justifying PSPS.

389. PG&E withdrew its proposal to create a safety-related shareholder earnings adjustment mechanism that ties a portion of annual earnings to PG&E's safety performance.

390. Separate MOUs between PG&E and SBUA, PG&E and CforAT, and PG&E and NDC are incorporated into the Settlement Agreement relating to PG&E's commitment to support small businesses, improving accessibility to its facilities,

and providing outreach and education to minorities and promoting supplier diversity.

391. Continuing to keep PG&E's Apprentice Lineman Training Program filled to the maximum extent is consistent with safe crew staffing ratios.

392. The requirements and design of a dimmable streetlight program will be addressed in PG&E's Phase 2 GRC proceeding.

393. PG&E shall be allowed to create a DSIMA to track any implementation costs incurred prior to 2023 and seek recovery of those costs in its next GRC application.

394. PG&E shall confer with SED regarding the qualifications of its safety work leaders in advance of PG&E's next GRC.

395. Three of the four helicopters are to be available to CAL FIRE under a "call when needed" contract during fire season.

396. The revenue requirement increases agreed upon by the settling parties in Article 2.1.2 of the Settlement Agreement are lower than PG&E's original proposal but higher than the amounts originally recommended by Cal Advocates.

397. The PTY method adopted in the Settlement Agreement uses the general method originally proposed by PG&E of applying escalation to determine O&M costs and basing capital revenue requirement growth on plant additions.

398. The PTY proposal in the Settlement Agreement provides separate PTY totals for Electric Generation, Electric Distribution, and Gas Distribution rather than a single escalation rate for all costs.

399. Applying the same general PTY ratemaking framework results in several differences between PG&E's and Cal Advocates' original proposals as the two

parties recommended different indexes for determining labor-related escalation and different methods for calculating the cost of capital additions.

400. The Z-Factor mechanism uses a series of eight criteria described in D.94-06-011 to identify exogenous cost changes that qualify for rate adjustments prior to PG&E's next GRC test year. Rate adjustments are allowed for only the portion of Z-Factor costs not already contained in the annual revenue requirement.

Issues Outside the Settlement

401. The JCCAs propose several changes to PG&E's Resilience Zone program, requesting that PG&E coordinate with local governments, PG&E accelerate the pace of Resilience Zone deployment, the Resilience Zones accommodate CCA-procured generation, and the Commission authorize funding for permanent clean generation and storage onsite at the Resilience Zones.

402. D.20-06-17 (the Microgrid OIR decision) addresses the JCCAs' issues, which include directing PG&E to collaborate with local government and coordinate with county emergencies service agencies, addressing the generation PG&E shall use in the Resilience Zones, and adopting solutions to accelerate Microgrid deployment.

403. The Grid Modernization Plan projects, which includes the Integrated Grid Platform, allow PG&E to obtain real-time energy data from the grid.

404. The JCCAs request that the Commission direct PG&E to share with CCAs, as well as other load-serving entities, the real-time energy data obtained through the Grid Modernization Plan projects.

405. The issue of whether to grant third party access to real-time energy data that are enabled by the grid modernization projects requires the Commission to weigh and consider many of the benefits and costs associated with allowing third

party access to the data and concerns policies that impact other energy utilities besides PG&E.

Conclusions of Law

1. Any outstanding motions or requests that have not been addressed in this decision or elsewhere in this proceeding are denied.
2. All oral and written rulings that the assigned ALJs have issued in this proceeding are affirmed.
3. We affirm that the category of this proceeding is ratesetting.

Gas Distribution

4. The reduction of $5.0 million to PG&E's forecast for MPP under Distribution and Mains represents a fair compromise between recommendations from PG&E, Cal Advocates and TURN.
5. Modification of the NERBA to retain the distribution subaccount until 2022 for the sole purpose of tracking costs associated with below ground Grade 3 leak repairs is reasonable.
6. The agreement concerning the replacement rate of pre-1985 Aldyl-A pipes represents a fair compromise between PG&E's proposals and objections and concerns raised by CUE and OSA and the replacement timeline plan addresses the need to establish a two-way balancing account for PG&E's pipeline replacement programs.
7. There is sufficient reason to justify PG&E's OPP Enhancements Program under Asset Family Measurement & Control and CNG.
8. The O&M and capital forecasts adopted by the Settlement Agreement are reasonable with the understanding that the 2018 capital forecast will be adjusted pursuant to Article 3.2 of the Settlement Agreement.

Electric Distribution

9. The forecast for routine VM is reasonable and falls within the range of costs previously incurred for these activities that are regularly performed by PG&E.

10. Recorded expenses for enhanced VM in 2018 is a good representation of future costs because the programs and projects included are the same.

11. The settlement reduction of $59.338 million was applied to the forecast for enhanced VM forecast as parties agree with PG&E's forecast for routine VM. With the above reduction, the adopted forecast for enhanced VM is close to recorded enhanced VM expenditures in 2018.

12. The settlement amount for VM and enhanced VM represents a fair compromise between party positions and takes into account recorded expenditures as well as concerns that PG&E's forecast is somewhat ambitious and lacks detail with regards to scope and pace of work.

13. The PTY amounts agreed upon for routine and enhanced VM work is reasonable because enhanced VM work is expected to ramp-up as the program becomes more fully developed.

14. Concerns that the settlement amount for VM may be inadequate for wildfire mitigation work is addressed by the settlement's proposal to modify the VMBA into a two-way balancing account.

15. Enhanced VM activities are relatively new but over time, we believe the distinction between routine and enhanced VM activities will disappear and all such activities will be referred to as VM activities.

16. Two-way treatment of VM costs is reasonable in light of the settlement reduction of more than $59 million to VM costs.

17. Modification of the VMBA into a two-way balancing account that tracks routine and enhanced VM costs is reasonable and review of undercollections

exceeding 120 percent of the authorized amount should be filed as a Tier 3 advice letter. However, undercollections exceeding 130 percent should be filed as an application to allow enhanced review.

18. ERDU activities are routine in nature but the volume of activity has significantly increased thus demonstrating in this GRC cycle that the activities are incremental in nature.

19. The O&M and capital forecasts adopted by the Settlement Agreement are reasonable with the understanding that the 2018 capital forecast will be adjusted pursuant to Article 3.2 of the Settlement Agreement.

20. CWSP-related capital projects under EP&R are necessary to further mitigate against wildfire risk.

21. There is a reasonable degree of certainty that planned weather stations for 2019 and 2020 will also be constructed based on 2018 spending and the same analogy can be made with respect to other planned capital projects.

22. Regarding the Surge Arrestor Program, arguments by opposing parties have merit and it is prudent to give due regard to the agreement reached by both sides to adopt PG&E's EDM capital forecasts.

23. The Non-exempt Replacement Program is necessary to maintain a firebreak from utility poles pursuant to section 4292 of the Public Resources Code.

24. Updates to PG&E's work plan for Pole Replacement projects address concerns raised by CUE concerning more pole replacements and achieving a steady state of replacements.

25. PG&E's concession to reduce the requested amount for Overhead System Hardening projects by approximately $236 million balances the concerns raised

by various parties and the need for expanded system hardening measures and programs for added wildfire mitigation and employee and public safety.

26. Replacement of antiquated oil-filled switches as they are discovered in the course of standard switch inspections can be viewed as reasonable prioritization in light of the many other high priority risk reduction programs being authorized in this GRC.

27. Continuation of the Rule 20A balancing account without any modifications is reasonable.

28. For IGP and Grid Modernization projects, it is more reasonable to consider the agreement reached by settling parties that may have had initial differences and different recommendations considering the forward-looking nature of such projects.

29. Authority to establish a two-way WMBA to record CWSP O&M and capital expenditures is supported by the record and should be authorized.

30. Using the 2020 CWSP capital forecast as a basis for CWSP capital projects in 2021 and 2022 provides a more accurate forecast going forward.

31. It is reasonable to modify the Settlement Agreement such that authorized CWSP capital amounts for 2021 and 2022 should be equal to the authorized capital funding for 2020 which is $603.341 million. The authorized annual unit costs for System Hardening in 2021 and 2022 should be set at the 2020 level, which is $1.2 million per overhead circuit mile and $4.4 million per underground circuit mile.

32. PG&E should be required to file an application for recovery of CWSP costs recorded in the WMBA if CWSP expenditures are in excess of 130 percent of the authorized amount or if recorded per mile unit costs are in excess of 130 percent of the authorized unit costs.

33. PG&E cannot earn an equity return on the first $3.21 billion of capital expenditures it spends on wildfire mitigation measures included in its approved wildfire mitigation plan.

34. It is reasonable to allow PG&E to earn a debt return, based on its currently authorized cost of debt, on the GRC CWSP capital expenditures until the Commission can decide PG&E's future section 850.1 application.

35. PG&E's authorized cost of debt is an appropriate forecast of the financing costs for the GRC CWSP capital expenditures.

36. It is reasonable to adopt the settling parties' proposed methodology of applying AB 1054 in calculating the annual revenue requirement reductions, which removes an equity return and the related taxes on the GRC CWSP capital expenditures, but PG&E should update its revenue requirement to reflect the cost of debt that is authorized at the time this decision is approved in the advice letter implementing this decision.

37. If PG&E seeks section 850.1 financing of CSWP capital costs, PG&E should adjust its GRC revenue requirement by removing the debt return and other capital-related expenses from its GRC forecast.

38. Recovery of other wildfire mitigation capital expenditures recorded in the WMPMA should be filed as an application instead of a Tier 2 advice letter.

Energy Supply

39. The O&M and capital forecasts for Hydro Operations, Natural Gas & Solar, Electric Procurement Administration, Technology Programs, and Nuclear Operations adopted by the Settlement Agreement are reasonable subject to the adjustment of 2018 capital costs pursuant to Article 3.2 of the Settlement Agreement.

40. Modification of the two-way HLBA to include regulatory fees, costs associated with implementation of the Crane Valley Recreation Settlement Agreement, and costs associated with work required due to the 2017 Oroville spillway incident is reasonable.

41. The Stator Replacement Project is necessary in order to continue operating DCPP safely and reliably for this GRC cycle.

42. DCCP's expected shutdown in 2024 and 2025 will be considered as an important factor but does not overcome the need to consider safety as the primary issue when looking at the necessity of projects and their costs.

43. Moving forward, it is proper to close the DCSSBA and review LTSP costs for ongoing operations in the GRC.

Customer Care

44. The settlement's adoption of a TY2020 forecast of $277.5 million in expenses and $140.2 million in capital expenditures for Customer Care is reasonable.

45. The settlement's adoption of PG&E's forecasted expenses and capital expenditures for the activities related to Customer Engagement, PG&E's proposed cost recovery and account treatment for the AB 802 memorandum accounts, the MOU between PG&E and SBUA, and PG&E's proposed cost recovery of the costs PG&E commits to spend in the MOU is reasonable.

46. The stipulation between PG&E and TURN to revise the forecast for AB 802 compliance expenses represents a fair compromise between the parties' initial positions and addresses TURN's original concerns that PG&E may have overestimated staffing needs.

47. The settlement's adoption of PG&E's unopposed forecasted expenses for the Income Qualified Programs is reasonable.

48. The forecasts for PG&E's non-residential rates implementation activities and for the Natural Gas Appliance Testing program, as adopted by a stipulation between TURN and PG&E and the settlement, are reasonable.

49. The forecast for the non-residential rate implementation activities adopted by the stipulation between TURN and PG&E represents a compromise of the parties' positions and addresses the concerns of both parties.

50. The settlement's proposed recovery of residential rate reform costs is reasonable.

51. The settlement's adoption of PG&E's forecasts for the Contact Centers Operations (CCOs), of which only the costs for the Salesforce Phase 2 and Phase 3 projects were initially contested by the parties, is reasonable.

52. The stipulation between TURN and PG&E on the project timeline and costs for the Salesforce Phase 2 and Phase 3 projects represents a compromise of TURN's and PG&E's original positions and is reasonable.

53. The settlement's adoption of PG&E's forecasts and proposals for the Customer Services Offices (CSOs) operations, other than PG&E's proposed closure of CSOs, is reasonable.

54. It is reasonable to direct PG&E to file a Tier 2 Advice Letter with Energy Division to close the CSOs.

55. It is reasonable to require PG&E to provide customer notifications prior to closing a CSO.

56. The settlement's adoption of PG&E's MOU with CforAT, as well as PG&E's proposed recovery of costs for the MOU, is reasonable.

57. The settlement's adoption of PG&E's forecasts for the Metering program, including the metering reading expenses, is reasonable.

58. The settlement's adoption of PG&E's forecasted expenses and proposals for the activities supporting PG&E's Billing, Revenue, and Credit operation and a $1.2 million reduction to PG&E's forecast for collection and payment processing activities is reasonable.

59. The settlement's adoption of PG&E's proposed fee reductions for its service reconnection service and NSF check returns is reasonable.

60. The settlement's adoption of PG&E's forecast for the uncollectible factor is reasonable.

61. The 3.4 percent increase to utility rates that would result from the settlement's revenue requirement represents a balance of customer affordability, reliability, and safety, particularly in light of the significant wildfire mitigation investments PG&E will need to make due to the heighted wildfire risks in our current environment.

62. Pub. Util. Code section 718(b) directs the Commission to consider the impact of any proposed increase in rates on disconnections for nonpayment and to incorporate a metric for residential nonpayment disconnections in each energy utility's general rate case proceeding.

63. It is reasonable to use the four percent annual cap ordered in D.20-06-003 as the metric for residential nonpayment disconnections.

64. The settlement's adoption of PG&E's forecasted expenses for the activities presented in the Regulatory Policy and Compliance section and a $2.8 million reduction to PG&E's forecast for Customer Care supervisory and management costs is reasonable.

Shared Services

65. The settlement reduction of approximately $4.9 million in CRESS costs represents a fare compromise between PG&E's forecast and Cal Advocates'

original recommendation. Both parties presented reasonable arguments in support of their positions but neither was able to establish that their position is more correct.

66. The O&M and capital forecasts for Safety and Health, TAS, Materials, Sourcing, Real Estate, Land and Environment Management, and ERIM adopted by the Settlement Agreement are reasonable subject to the adjustment of 2018 capital costs pursuant to Article 3.2 of the Settlement Agreement.

67. The forecasts adopted by the Settlement Agreement for Shared Services Company-wide Expenses are consistent with historical expenditures and should be adopted.

68. The proposed purchase of four firefighting helicopters is reasonable and necessary based on the evidence presented.

69. As discussed in the IT and Cyber security chapter, the O&M and capital forecasts adopted by the Settlement Agreement are reasonable subject to the adjustment of 2018 capital costs pursuant to Article 3.2 of the Settlement Agreement.

70. The reduction of PG&E's IT forecast adequately addresses TURN's concern, promotes customer affordability, and will not negatively impact safety, reliability, and the amount and level of service that PG&E provides to customers.

Human Resources

71. The O&M forecasts adopted by the Settlement Agreement for Department Costs and Companywide Expenses as well as the O&M and capital forecasts for IT Expenses and IT capital are reasonable subject to the adjustment of 2018 IT capital costs pursuant to Article 3.2 of the Settlement Agreement.

72. The labor escalation rates agreed-upon in the settlement are reasonable and will enable PG&E's salaries to remain competitive and not negatively impact

the level of service provided by PG&E or its ability to perform its duties and obligations in a safe and reliable manner.

73. The escalation factor adopted in this decision is reasonable in light of the entirety of the Settlement Agreement and the record of the proceeding.

74. The amortization of costs for the Total Compensation Study is adequately addressed by the $1.203 million reduction in the Settlement Agreement due to affordability considerations.

75. STIP costs should be shared when STIP expenses benefit both ratepayers and shareholders.

76. In deciding how to address shared benefits between ratepayers and shareholders, it is more reasonable in this case in light of the Settlement Agreement to consider an overall reduction to STIP costs rather than examine each metric individually as was done in D.19-09-051.

77. The settlement reduction of $88.0 million or approximately 50.72 percent from PG&E's proposal represents a fair compromise between different and opposing positions between PG&E and other parties and is within the range of outcomes presented by PG&E and other parties.

78. The settlement reduction of $1.973 million to Health and Welfare Benefits is reasonable in light of historical costs from 2013 to 2017 and represents a fair compromise between various positions of the settling parties and of FEA.

79. In light of the Settlement Agreement, it is more reasonable in this case to consider overall costs of Health and Welfare and Other Benefits rather than individual elements such as medical benefits, vision benefits, employee awards, etc.

Administrative and General

80. For A&G costs, the applied allocation factor of approximately 83.09 percent utilized to determine the GRC net amount from total company amount is reasonable.

81. The O&M forecasts adopted by the Settlement Agreement for Department Costs and Companywide Expenses as well as the O&M and capital forecasts for IT Expenses and IT capital are reasonable subject to the adjustment of 2018 IT capital costs pursuant to Article 3.2 of the Settlement Agreement.

82. The reduction for General Liability insurance of $60.173 million to PG&E's forecast represents a fair compromise between party positions and are within the range of outcomes that were proposed especially by PG&E and TURN.

83. Authority to establish a two-way RTBA is reasonable and consistent with the authority granted to establish the two-way Liability Insurance Premium Balancing Account in the TY2019 GRCs of SDG&E and SoCalGas. However, undercollections exceeding 130 percent should be filed as an application to allow enhanced review.

84. PG&E originally sought to obtain $2 billion worth of General Liability insurance and $1.4 billion of coverage represents a fair compromise with the proposals from other parties.

85. The mechanics and principles concerning the self-insurance fund described in Article 2.8.3.3 of the Settlement Agreement are reasonable and allow PG&E to invest unspent amounts authorized for General Liability insurance when competitively-priced insurance available in the market is limited.

86. Recovery of the $66.944 million recorded in the WEMA as authorized in D.18-06-029 is reasonable.

87. The proposed amortization of the GRC portion of the WEMA costs being recovered (S60.448 million) over a three-year period beginning January 1, 2020 is reasonable.

Results of Operations

88. The settlement's adoption of PG&E's unopposed forecasts for Special Deposits and Working Funds is reasonable.

89. The settlement's adoption of a $23 million revenue requirement reduction to PG&E's forecast for Other Receivables represents a reasonable compromise of the parties' original positions and is reasonable.

90. The settlement's adoption of PG&E's unopposed forecast of Prepayments is reasonable.

91. The settlement's adoption of PG&E's proposed forecasts and proposals for Deferred debits is reasonable.

92. The settlement's adoption of PG&E's forecasted deductions for Goods Delivered to Construction Sites is reasonable.

93. The settlement's adoption of PG&E's unopposed forecast for Accrued vacation is reasonable.

94. The settlement's adoption of PG&E's unopposed forecast for Working cash not supplied by investors is reasonable.

95. It is reasonable to adjust the revenue lag to account for the timing difference of when the greenhouse gas climate credit refunds are recognized.

96. The settlement's adoption of PG&E's TY 2020 revenue lag, in addition to a revenue requirement reduction of $10 million to account for the timing difference of recognizing greenhouse gas climate credit refunds, is reasonable.

97. The settlement's proposal for a $26 million reduction in revenue requirement for the removal of the carrying costs of greenhouse gas compliance from the Working Capital forecast is reasonable.

98. The settlement's adoption of PG&E's unopposed forecast for Customer Advances is reasonable.

99. The settlement's proposal to continue the ratemaking treatment granted in PG&E's 2020 Cost of Capital decision for Customer Deposits is reasonable.

100. It is reasonable for PG&E to file a Tier 2 Advice Letter to make any necessary corrections to the ratebase and revenue requirement to reflect the removal of customer deposits ordered in D.20-06-003, effective June 11, 2020.

101. Adopting the 2017 depreciation parameters, which include the average service lives, survivor curves, and net salvage percentages, is reasonable.

102. The service life forecasts and survivor curves adopted by the settlement are reasonable.

103. The net salvages percentages adopted by the settlement are reasonable.

104. The depreciation reserve and depreciation expenses proposed by the settlement agreement support the concept of intergenerational equity and are reasonable.

105. The depreciation reserve and depreciation expenses adopted by the Settlement Agreement, including the settlement's $150 million revenue requirement reduction to PG&E's proposed depreciation expenses, are reasonable.

106. The settlement agreement modifies some of the depreciation parameters adopted by the stipulation and will result in a $150 million revenue requirement reduction for PG&E's depreciation expenses.

107. PG&E's forecasted tax expenses and method for calculating tax expenses are reasonable.

108. The modifications to the Tax Memorandum Account (TMA) proposed by the settlement represent a reasonable balance between the parties' positions and are reasonable.

109. The settlement's proposal to have PG&E file an advice letter to correctly reflect the return of excess ADIT created by the passage of the 2017 Tax Act is reasonable.

110. The settlement's adoption of PG&E's forecast and forecasting methodology for OORs is reasonable.

111. The settlement's proposal to allocate specific Community Wildfire Safety Program (CWSP) costs that PG&E incurs to support wildfire mitigation efforts that benefit all utility functions as common costs is reasonable.

112. The settlement's proposal to allocate Locate and Mark costs 33.3 percent to electric distribution and 66.7 percent to gas distribution is reasonable.

113. The settlement's proposed cost allocation of the excess liability insurance is reasonable.

114. PG&E should examine in its next GRC whether functionalizing its excess liability insurance and general liability insurance coverage as common costs is still appropriate.

115. The settlement's proposal to functionalize 100 percent of the Pricing Products and Income Qualified rate programs costs, which pertain only to electric customers, to the electric distribution function, is reasonable.

116. The settlement's proposal to functionalize the MWC EV and MAT EVA costs based on the number of electric and gas service agreements, which results

in allocating 55 percent of the costs to the electric distribution function and 45 percent of the costs to the gas distribution function, is reasonable.

117. It is reasonable to allocate 100 percent of the CWSP costs that directly support electric distribution assets, including the costs of the Resilience Zones program, to the electric distribution function.

118. It is reasonable to allocate the grid modernization costs to the electric distribution function.

119. It is appropriate to allocate customer care costs following the principle of cost causation, which allocates costs to the group of customers that incur the costs.

120. It is reasonable for PG&E to maintain its current functionalization of customer care costs, allocating customer care costs between gas distribution and electric distribution functions, based on the number of gas and electric service agreements.

121. For its next GRC, PG&E should track and report data showing the extent to which its customer care services and programs support its electric generation function as compared to its electric distribution and gas distribution functions.

122. Pub. Util. Code section 366.2(a)(4) states that "the implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation."

123. It is reasonable to implement measures to prevent cost subsidies between departed customers and bundled customers.

124. PG&E should provide in its next GRC a better showing of its cost functionalization process to prevent possible cost subsidies between the bundled and unbundled customers.

125. PG&E should provide in its next GRC detailed testimony showing and justifying how it allocates costs across its various utility functions, including how it derives its functional allocations.

Other Adjustments and Terms / PTY

126. It is reasonable to modify the Settlement Agreement in order to include the updated RO model reflecting 2018 recorded capital costs as an additional appendix to the Settlement Agreement.

127. It is reasonable to apply the updated RO model to Attachments B and C of the decision and to the overall revenue requirement being authorized in this decision.

128. Applying the updated RO model to the overall revenue requirement authorized in this decision does not contravene the agreements set forth in the Settlement Agreement.

129. The proposed PTY amounts in the Settlement Agreement represents a fair compromise between the testimony and arguments presented by both PG&E and Cal Advocates as both parties presented reasonable arguments in support of their positions but neither party was able to establish that their recommended method is better than the other.

130. The PTY amounts adopted in the Settlement Agreement should be revised to reflect reductions to the authorized amounts for CWSP capital for 2021 and 2022 as discussed in the WMBA section of the decision (Section 7.4).

131. As discussed in the PTY chapter of the decision, continuation of the Z-Factor memorandum account to track costs associated with exogenous and unforeseen events that are largely beyond PG&E's control is reasonable.

132. Tracking Z-Factor events that may occur during the TY is consistent with D.19-09-051.

133. It is assumed that each Z-Factor event will only include costs in excess of a $10 million deductible per event as specified in PG&E's unopposed testimony regarding this issue.

Issues Outside the Settlement

134. The Resilience Zone issues raised by the JCCA are more appropriately addressed in R.19-09-009 (Microgrid OIR).

135. The issue of whether to grant third party access to real-time energy data is more appropriately addressed in R.14-08-013, Distributed Resource Planning (DRP) proceeding.

136. The Resilience Zone issues raised by the JCCA are out of the scope of this proceeding.

137. PG&E's compliance with the United States District Court's probation is not an issue within the scope of the GRC.

138. Issues related to PG&E's bankruptcy are outside the scope of this proceeding.

O R D E R

IT IS ORDERED that:

1. The January 14, 2020 "Joint Motion for Approval of Settlement Agreement regarding Pacific Gas and Electric Company's (PG&E) Test Year 2020 General Rate Case, including Post-Test Years (PTY) 2021 and 2022" (Settlement Motion) is granted subject to the following modifications to the Settlement Agreement attached to the Settlement Motion:

    a. Articles 2.3.4.2.1 and 2.3.4.2.2 of the Settlement Agreement are modified such that recovery of costs in excess of 130 percent of the authorized amount for Vegetation Management shall be made by application instead of by a Tier 3 advice letter.

    b. Articles 2.3.2.1 and 2.3.2.2 of the Settlement Agreement are modified as follows:

Community Wildfire Safety Program (CWSP) Capital: $603.341 million for 2021 and 2022
Overhead per Circuit Mile Cost: $1.2 million for 2021 and 2022
Underground per Circuit Mile Cost: $4.4 million for 2021 and 2022
As a result, the proposed revenue requirements for PTYs 2021 and 2022 specified in Article 2.1.2 of the Settlement Agreement should also be adjusted to reflect the above modifications to the authorized CWSP amounts. Article 2.3.2.2 is further modified as described in the next sub-section.

c. Articles 2.3.2.2, 2.3.2.2.1, and 2.3.2.2.2 of the Settlement Agreement are modified such that recovery of costs in excess of 130 percent of the authorized amounts for CWSP or if recorded average per circuit mile unit costs exceed 130 percent of the authorized per circuit mile unit cost, shall be made by application instead of a Tier 3 advice letter.

d. Article 2.3.2.4 of the Settlement Agreement is modified such that recovery of other fire risk mitigation capital expenditures not included or not adopted in this General Rate Case shall be made by application instead of a Tier 3 advice letter. To ensure compliance with AB 1054, PG&E shall make an explicit showing in its Annual Electric True-Up advice letter filings going-forward to report the total amount of PG&E's $3.21 billion wildfire mitigation capital that has been found just and reasonable and excluded from equity rate base, in which proceeding this finding has occurred, and the remaining amount and plan for the wildfire mitigation capital that has yet to be excluded from rate base.

e. Article 2.5.6 of the Settlement Agreement is modified such that PG&E's proposed closure of up to 10 Customer Services branch offices shall be filed via a Tier 3 advice letter instead of a Tier 1 advice letter and the advice letter shall include the amount of savings PG&E will achieve through the office closures and the updated selection criteria as set forth in Section 9.4.5 of this Decision.

f. Article 2.8.3.2 of the Settlement Agreement is modified such that recovery of costs in excess of 130 percent of the authorized amount for General Liability insurance shall be made by application instead of by a Tier 3 advice letter.

g. The updated Results of Operations Model (RO Model) tables reflecting recorded 2018 capital expenditures shall be attached to the Settlement Agreement as an additional appendix and Article 3.2 of the Settlement Agreement is modified such that the adjustments to the RO Model to replace the 2018 capital forecast amounts with 2018 recorded amounts are already reflected in the amounts authorized in this decision instead of in the final implementation advice letter.

Pursuant to Rule 12.4(c) of the Commission's Rules of Practice and Procedure, parties to the Settlement Agreement shall have 15 days from today's date to file with the Docket Office and serve either a "Notice to Accept" the above modifications to the Settlement Agreement or a "Motion Requesting Other Relief," if any of the above modifications are not accepted. Parties may respond to the "Motion Requesting Other Relief" as provided for in Rule 11.1.

2. Pursuant to the modifications described in Ordering Paragraph 1, Pacific Gas and Electric Company is authorized to collect, through rates and through authorized ratemaking accounting mechanisms, the 2020 test year base revenue requirement set forth in Appendix B and further described in the Settlement Agreement, effective January 1, 2020. In the event a "Motion Requesting Other Relief" is filed, the test year base revenue requirement set forth in Appendix B shall remain in effect until a decision resolving the request for other relief is adopted by the Commission.

3. Within 20 days from the effective date of this Order, Pacific Gas and Electric Company (PG&E) shall file a Tier 1 advice letter with revised tariff sheets to implement the revenue requirement authorized in Ordering Paragraph 2

a. In accordance with D.19-11-004, the revised tariff sheets shall become effective on January 1, 2020 subject to a finding of compliance by the Commission's Energy Division, and compliance with General Order 96-B.

b. The balance recorded in PG&E's General Rate Case Revenue Requirement Memorandum Account from January 1, 2020 until the date the new tariffs are implemented, pursuant to this Ordering Paragraph, shall be amortized in rates beginning January 1, 2021 through December 31, 2022.

4. Pacific Gas and Electric Company is authorized to implement a Post-Test Year Ratemaking mechanism for 2021 and 2022 as described in the Settlement Agreement, subject to the applicable modifications described in Ordering Paragraph 1.

5. To update its revenue requirement for Post-Test Year (PTY) 2021, Pacific Gas and Electric Company shall file a Tier 1 advice letter with the Commission's Energy Division at the same time it files the implementing advice letter to update the Test Year revenue requirement as described in Ordering Paragraph 3. The PTY 2021 update shall be effective on January 1, 2021 through December 31, 2021.

6. To adjust its revenue requirement for Post-Test Year 2022, Pacific Gas and Electric Company shall file a Tier 1 advice letter with the Commission's Energy Division two months prior to January 1, 2022. This update shall be effective on January 1, 2022 through December 31, 2022.

7. Pursuant to the Settlement Agreement, Pacific Gas and Electric Company's regulatory account proposals are authorized subject to the modifications described in Ordering Paragraph 1 with respect to recovery of amounts that may be recorded in the Wildfire Mitigation Balancing Account and the Vegetation Management Balancing Account.

8. In addition to the modification specified in Ordering Paragraph 1 regarding the Vegetation Management Balancing Account, recovery of any

undercollection that is less than 120 percent of the authorized amount as well as the refund any overcollection, shall be filed via a Tier 2 advice letter.

9. In addition to the modification specified in Ordering Paragraph 1 regarding the Wildfire Mitigation Balancing Account, recovery of any undercollection that is less than 115 percent of the authorized amount as well as the refund any overcollection, shall be filed via a Tier 2 advice letter.

10. The following regulatory accounts shall continue without any modification from the Earning Adjustment Mechanism: (a) Distribution Revenue Adjustment Mechanism; (b) Utility Generation Balancing Account; (c) Core Fixed Cost Account; and (d) Noncore Customer Class Charge Account (NCA).

11. Pacific Gas and Electric Company shall be allowed to earn a debt return on the Community Wildfire Safety Program capital costs authorized in this decision.

a. Pacific Gas and Electric Company shall update its revenue requirement to reflect the cost of debt that is authorized at the time this decision is approved in the advice letter implementing this decision.

b. If Pacific Gas and Electric Company (PG&E) files an application pursuant to section 850.1 of the Public Utilities Code to finance its wildfire mitigation capital expenditures in this General Rate Case (GRC), in such application, PG&E shall also adjust its GRC revenue requirement by removing the debt return and other capital-related expenses from its GRC forecast.

12. Within 45 days from the effective date of this Order, Pacific Gas and Electric Company (PG&E) shall file a Tier 2 advice letter to return to ratepayers the excess Accumulated Deferred Income Taxes that was created by the passage of the 2017 Tax Act.

a. PG&E shall show the revenue requirement reductions for 2020, 2021, and 2022 and include a proposed amortization period for the reductions.

13. Within 90 days from the date of this Order, Pacific Gas and Electric Company shall file a Tier 2 advice letter to adjust the revenue requirements authorized by this decision to reflect the prohibition against collecting Customer Deposits pursuant to Decision 20-06-003 which became effective on June 11, 2020.

14. Notification to close a customer services branch office pursuant to Article 2.5.6 of the Settlement Agreement shall be made by mail, posting, and published notice.

a. All notices must be multilingual and should include prominent statements regarding the proposed office closures and the Commission's 800-telephone number.

b. 60 days prior to filing the Tier 3 advice letter to close up to 10 branch offices, Pacific Gas and Electric Company shall solicit comments from customers and include a compiled summary of comments with the advice letter filing.

15. In its next General Rate Case, Pacific Gas and Electric Company shall submit testimony whether its annual replacement rate of load break oil rotary switches is still viable or whether the rate of replacement needs to be increased.

16. In its next General Rate Case (GRC), Pacific Gas and Electric Company shall include testimony on the actual annual percentages of residential utility disconnections for nonpayment during this GRC cycle and an analysis of the impact rate increases have on disconnections during this GRC period.

17. Pursuant to Decision 20-06-003, which set an annual cap of four percent on the percentage of residential customer accounts that Pacific Gas and Electric Company can disconnect from utility service in 2020, 2021, and 2022, this decision shall apply the four percent cap as the metric for residential nonpayment disconnections as directed in Public Utilities Code Section 718(b).

18. In its next General Rate Case (GRC), Pacific Gas and Electric Company (PG&E) shall provide testimony showing how it allocates costs across its various

utility functions, how it derives its functional allocations, and how it functionalizes costs associated with common plants.

a. PG&E shall also provide detailed explanation and reasoning to justify the cost allocation it proposes for excess liability insurance costs in its next GRC.

b. PG&E shall also track and report data showing the extent to which its customer care services and programs support its electric generation function as compared to its electric distribution and gas distribution functions and include this data to support its proposed cost allocation method of customer care expenses.

19. Each Z-Factor event shall only include costs in excess of a $10 million deductible per event.

20. Pacific Gas and Electric Company's risk showing in its next General Rate Case shall comply with the settlement agreement in Decision 18-12-014.

21. In its next General Rate Case, Pacific Gas and Electric Company shall include testimony that shows or explains how its Risk Spend Efficiency (RSE) calculations comply with the following section of Resolution WSD-002:

> RSE is not an appropriate tool for justifying the use of PSPS. When calculating RSE for PSPS, electrical corporations generally assume 100 percent wildfire risk mitigation and very low implementation costs because societal costs and impact are not included. When calculated this way, PSPS will always rise to the top as a wildfire mitigation tool, but it will always fail to account for its true costs to customers. Therefore, electrical corporations shall not rely on RSE calculations as a tool to justify the use of PSPS.

22. A decision in Rulemaking 17-05-010 that impacts Pacific Gas and Electric Company's Rule 20B and 20C programs during this General Rate Case Cycle shall supersede funding authorized in this decision for these programs.

23. Application 18-12-009 shall be closed following the filing by the settling parties of a "Notice to Accept" the modifications to the Settlement Agreement specified in Ordering Paragraph 1.

   a. In the event a "Motion Requesting Other Relief" is filed in connection with this proceeding, Application 18-12-009 shall remain open until a decision or ruling resolves the motion, and the issue raised by this motion shall extend the time for resolving this matter by another 18 months as provided for in Public Utilities Code section 1701.5.

This decision is effective today.

Dated _____________, at San Francisco, California.

APPENDIX A
Pacific Gas and Electric Company
2020 CPUC General Rate Case (GRC)
Glossary of Terms

Terms	Definitions
A&G	Administrative and General
A.	Application
A4NR	Alliance for Nuclear Responsibility
AB	Assembly Bill
AB802MA	AB 802 Memorandum Account
Ad Hoc Committee	Ad Hoc Committee of Senior Unsecured Noteholders to PG&E
ADIT	Accumulated Deferred Income Taxes
ADMS	Advanced Distribution Management System
AET	Annual Electric True-up
ALJ	Administrative Law Judges
AOC	Abnormal Operating Conditions
APC	Asset Performance Center
BRC	Billing, Revenue, and Credit
Cal Advocates	The Public Advocate's Office
CALSLA	California City/ County Streetlight Association
CARB	California Air Resources Board
CARE	California Alternative Rates Energy
CCA	Community Choice Aggregators
CCO	Contact Centers Operations
CCRPC	Customer Care Regulatory Policy and Compliance
CEMA	Catastrophic Event Memorandum Account
CFCA	Core Fixed Cost Account
CforAT	Center for Accessible Technology
CMEP	Community Microgrid Enablement Program
CNG	Compressed Natural Gas
Colusa	Colusa Generating Station
CPI	Consumer Price Index
CRESS	Corporate Real Estate Strategy and Services
CSO	Customer Services Offices
CUE	Coalition of California Utility Employees
CWIP	Construction Work In Progress
CWSP	Community Wildfire Safety Program
D.	Decision
DAP	Distribution Automation & System Protection
DCC	Distribution Control Center
DCPP	Diablo Canyon Power Plant
DCRBA	Diablo Canyon Retirement Balancing Account
DCSSBA	Diablo Canyon Seismic Studies Balancing Account
DER	Distributed Energy Resources
DGEMS	Distributed Generation Enabled Microgrid Services
DIMP	Distribution Integrity Management Program
DOE	Department of Energy
DOT	Department of Transportation
DRAM	Distribution Revenue Adjustment Mechanism
DRCBA	Diablo Canyon Retirement Account

Terms	Definitions
DRP	Distributed Resource Planning
DSIMA	Dimmable Streetlight Implementation Memorandum Account
DSO	Distribution System Operations
EAM	Earnings Adjustment Mechanism
EAP	Employee Assistance Program
ECAP	Enterprise Corrective Action Program
ECPS	Enhanced Cathodic Protection Survey
EDM	Electric Distribution Maintenance
EDR	Economic Development Rate
EER	Electric Emergency Recovery
EFO	Earnings from Operations
EGI	Electric Grid Interconnection
EOC	Emergency Operations Center
EP&R	Emergency Preparedness and Response
EPP	The Energy Policy and Procurement
EPUC	Energy Producers and Users Coalition
ERDU	Electric Data Response Unit
ERIM	Enterprise Records and Information Management
ERRA	Energy Resource Recovery Account
EVM	Enhanced Vegetation Management
FAI	Field Asset Inventory
FAU	Facilities Asset Upkeep
FEA	Federal Executive Agencies
FERC	Federal Energy Regulation Commission
FHPMA	Fire Hazard Prevention Memorandum Account
FLISR	Fault Location, Isolation and Service Restoration
FMO	Field Meter Operation
FTE	Full-Time Employee
Gateway	Gateway Generating Station
GDCC	Gas Distribution Control Center Operations
GHG	Greenhouse Gas
GIS	Geographic Information System
GO	General Order
GRC	General Rate Case
GRCMA	General Rate Case Memorandum Account
GSR	Gas Service Representatives
HCP	Habitat Conservation Plan
HFTD	High Fire Targeted Districts
HLBA	Hydro Licensing Balancing Account
HPR	High-Pressure Regulator
HR	Human Resources
Humboldt	Humboldt Bay Generating Station
IDM	Integrated Disability Management
IGP	Integrated Grid Platform
IIRCTA	Incremental Inspection and Removal Cost Tracking Account

Terms	Definitions
IRV	Internal Relief Valves
IS	Indicated Shippers
ISFSI	Independent Spent Storage Installation
JCCA	Joint Community Choice Aggregators
KernTax	Kern County Taxpayers Association
LBOR	Load Break Oil Rotary
LEM	Land and Environmental Management
LIPBA	Liability Insurance Premium Balancing Account
LOB	Line of Business
LTD	Long-Term Disability
LTSA	Long-Term Service Agreement
LTSP	Long Term Seismic Program
MBCP	Monterey Bay Community Power
ME&O	Marketing Education & Outreach
ME&O	Marketing, Education, and Outreach
MEBA	Major Emergencies Balancing Account
Mendocino	County of Mendocino
MOU	Memorandum of Understanding
MPP	Meter Protection Program
MS&E	Metering Services and Engineering
MWC	Major Work Category
Napa	County of Napa
NCA	Noncore Customer Class Charge Account
NCR	Nuclear Regulatory Commission
NDC	National Diversity Coalition
NERBA	New Environmental Regulation Balancing Account
NGLAPBA	Natural Gas Leak Abatement Program Balancing Account
NPC	Neighborhood Payment Centers
NRCRBA	Nuclear Regulatory Commission Regulatory Balancing Account
NSF	Non-Sufficient Funds
O&M	Operations and Maintenance
OEC	Operations Emergency Centers
OIR	Order Instituting Rulemaking
OM	Operational Management
OOR	Other Operating Revenues
OPP	Overpressure Protection
OS	Operation Support
OSA	Office of Safety Advocate
PDP	Peak-Day Pricing
PG&E	Pacific Gas and Electric Company
PHC	Preliminary Hearing Conference
PPH	Public Participation Hearing
PSPS	Public Safety Power Shut Offs
PTY	Post-Test Year
PV	Photovoltaic

Terms	Definitions
R&D	Research and Development
R20ABA	Rule 20A Balancing Account
RAMP	Risk Assessment Mitigation Phase
REC	Regional Emergency Centers
Reid	L. Jan Reid
Res.	Resolution
RO	Results of Operations
RRRMA	Residential Rate Reform Memorandum Account
RTBA	Risk Transfer Balancing Account
San Francisco	City and County of San Francisco
Santa Rosa	City of Santa Rosa
SAP	System Application and Products
SBUA	Small Business Utility Advocates
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison Company
Scoping Memo	Scoping Memorandum and Ruling
SDG&E	San Diego Gas & Electric Company
SED	Safety and Enforcement Division
SEIA	Solar Energy Industries Association
SoCalGas	Southern California Gas Company
Sonoma	County of Sonoma
SSHAC	Senior Seismic Hazards Analysis Committee
STIP	Short Term Incentive Payments
SVCE	Silicon Valley Clean Energy
SWMEOBA	Statewide, Marketing, Education & Outreach Balancing Accounts
TANC	Transmission Agency of Northern California
TAP	Technical Assistance Program
TAS	Transportation and Aviation Services
TC	Total Company
TMA	Tax Memorandum Account
TOU	Time-of-Use
TSP	Technology, Strategy, and Planning
TURN	The Utility Reform Network
TY	Test Year
UCC	Unbundled Cost Category
UGBA	Utility Generation Balancing Account
UTA	Unable-To-Access
VM	Vegetation Management
VMBA	Vegetation Management Balancing Account
WC	Workers Compensation
WEM	Women's Energy Matters
WEMA	Wildfire Expense Memorandum Account
WMBA	Wildfire Mitigation Balancing Account
WMP	Wildfire Mitigation Plan
WMPMA	Wildfire Mitigation Plan Memorandum Account

Terms	Definitions
WRO	Work at the Request of Others
WSOC	Wildfire Safety Operations Center

(END OF APPENDIX A)

APPENDIX B

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Decision Tables - Summary of Earnings (Test Year 2020)

APPENDIX B

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Decision Tables - Summary of Earnings (Test Year 2020)

TABLE INDEX

APPENDIX B: Table 1

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Adopted Results of Operations at Proposed Rates

Electric and Gas Departments Summary

(Thousands of Dollars)

Line No.	Description	Adj Recorded Year 2017RA (B)	Estimated Year 2018 (C)	Estimated Year 2019 (D)	Test Year 2020 (E)	Line No.
	REVENUE:					
1	Revenue Collected in Rates	8,014,182	8,171,114	8,517,725	9,102,470	1
2	Plus Other Operating Revenue	170,111	170,111	170,111	194,587	2
3	Total Operating Revenue	8,184,294	8,341,225	8,687,837	9,297,057	3
	OPERATING EXPENSES:					
4	Energy Costs	0	0	0	0	4
5	Production / Procurement	646,529	607,880	637,530	625,606	5
6	Storage	0	0	0	0	6
7	Transmission	9,513	11,095	9,798	9,986	7
8	Distribution	1,004,650	1,378,162	1,389,366	1,437,596	8
9	Customer Accounts	271,106	267,298	245,070	245,782	9
10	Uncollectibles	27,307	28,088	28,915	29,845	10
11	Customer Services	36,386	48,470	50,836	30,764	11
12	Administrative and General	1,000,248	1,117,841	1,259,832	1,203,064	12
13	Franchise & SFGR Tax Requirement	65,291	67,888	70,702	75,503	13
14	Amortization	176	174	172	23,271	14
15	Wage Change Impacts	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	16
17	Other Adjustments	(21,665)	(21,322)	(21,305)	(1,721)	17
18	Subtotal Expenses:	3,039,544	3,505,575	3,670,917	3,679,695	18
	TAXES:					
19	Superfund	0	0	0	0	19
20	Property	280,569	304,407	328,760	350,300	20
21	Payroll	107,367	91,869	95,561	95,862	21
22	Business	1,088	1,124	1,161	1,199	22
23	Other	6,713	10,606	13,470	13,723	23
24	State Corporation Franchise	88,377	37,685	67,164	117,148	24
25	Federal Income	376,395	(74,426)	(41,530)	97,424	25
26	Total Taxes	860,510	371,265	464,587	675,655	26
27	Depreciation	2,324,312	2,460,143	2,621,644	2,665,083	27
28	Fossil/Hydro Decommissioning	(5,527)	(5,527)	(5,527)	23,259	28
29	Nuclear Decommissioning	0	0	0	0	29
30	Total Operating Expenses	6,218,839	6,331,455	6,751,620	7,043,692	30
31	Net for Return	1,965,455	2,009,770	1,936,216	2,253,366	31
32	Rate Base	25,209,967	26,470,922	27,745,023	29,462,512	32

APPENDIX B: Table 1-A

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Adopted Results of Operations at Proposed Rates

Electric Distribution Summary

(Thousands of Dollars)

Line No.	Description	Adj Recorded Year 2017RA (B)	Estimated Year 2018 (C)	Estimated Year 2019 (D)	Test Year 2020 (E)	Line No.
	REVENUE:					
1	Revenue Collected in Rates	4,156,740	4,181,565	4,364,245	4,799,849	1
2	Plus Other Operating Revenue	135,983	135,983	135,983	158,665	2
3	Total Operating Revenue	4,292,723	4,317,548	4,500,228	4,958,514	3
	OPERATING EXPENSES:					
4	Energy Costs	0	0	0	0	4
5	Production / Procurement	0	0	0	0	5
6	Storage	0	0	0	0	6
7	Transmission	1,866	2,177	1,922	1,959	7
8	Distribution	632,425	1,026,211	1,040,044	1,057,769	8
9	Customer Accounts	156,136	154,086	143,082	138,328	9
10	Uncollectibles	14,510	14,740	15,184	16,128	10
11	Customer Services	24,976	32,961	35,261	14,417	11
12	Administrative and General	438,396	494,794	554,484	529,708	12
13	Franchise & SFGR Tax Requirement	32,518	33,307	34,718	38,258	13
14	Amortization	0	0	0	0	14
15	Wage Change Impacts	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	16
17	Other Adjustments	(915)	(727)	(718)	7,571	17
18	Subtotal Expenses:	1,299,912	1,757,548	1,823,978	1,804,138	18
	TAXES:					
19	Superfund	0	0	0	0	19
20	Property	168,991	181,286	194,359	206,535	20
21	Payroll	48,076	37,578	38,738	38,850	21
22	Business	487	503	520	537	22
23	Other	3,006	4,749	6,032	6,145	23
24	State Corporation Franchise	70,152	14,055	27,369	66,142	24
25	Federal Income	281,748	(79,395)	(58,824)	57,088	25
26	Total Taxes	572,461	158,776	208,193	375,296	26
27	Depreciation	1,356,840	1,420,387	1,510,763	1,498,006	27
28	Fossil/Hydro Decommissioning	0	0	0	0	28
29	Nuclear Decommissioning	0	0	0	0	29
30	Total Operating Expenses	3,229,213	3,336,711	3,542,934	3,677,439	30
31	Net for Return	1,063,510	980,837	957,294	1,281,075	31
32	Rate Base	14,405,326	14,947,646	15,798,153	16,817,603	32

APPENDIX B: Table 1-B

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Adopted Results of Operations at Proposed Rates

Gas Distribution Summary

(Thousands of Dollars)

Line No.	Description	Adj Recorded Year 2017RA (B)	Estimated Year 2018 (C)	Estimated Year 2019 (D)	Test Year 2020 (E)	Line No.
	REVENUE:					
1	Revenue Collected in Rates	1,747,033	1,888,502	1,962,559	2,013,276	1
2	Plus Other Operating Revenue	28,091	28,091	28,091	27,167	2
3	Total Operating Revenue	1,775,124	1,916,593	1,990,650	2,040,443	3
	OPERATING EXPENSES:					
4	Energy Costs	0	0	0	0	4
5	Production / Procurement	2,834	2,305	2,257	2,086	5
6	Storage	0	0	0	0	6
7	Transmission	0	0	0	0	7
8	Distribution	372,225	351,951	349,322	379,827	8
9	Customer Accounts	110,711	109,617	98,679	103,980	9
10	Uncollectibles	5,644	6,154	6,318	6,242	10
11	Customer Services	11,410	14,915	15,028	15,773	11
12	Administrative and General	260,676	293,863	328,795	313,847	12
13	Franchise & SFGR Tax Requirement	16,741	18,326	19,035	19,513	13
14	Amortization	0	0	0	0	14
15	Wage Change Impacts	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	16
17	Other Adjustments	(749)	(595)	(587)	5,153	17
18	Subtotal Expenses:	779,492	796,537	818,847	846,421	18
	TAXES:					
19	Superfund	0	0	0	0	19
20	Property	54,539	62,941	72,192	80,869	20
21	Payroll	27,967	24,927	25,099	26,122	21
22	Business	283	293	302	312	22
23	Other	1,749	2,763	3,509	3,574	23
24	State Corporation Franchise	(1,164)	4,560	11,750	8,037	24
25	Federal Income	15,459	3,057	7,467	10,399	25
26	Total Taxes	98,833	98,540	120,319	129,313	26
27	Depreciation	461,772	490,244	527,021	507,664	27
28	Fossil/Hydro Decommissioning	0	0	0	0	28
29	Nuclear Decommissioning	0	0	0	0	29
30	Total Operating Expenses	1,340,096	1,385,320	1,466,187	1,483,398	30
31	Net for Return	435,028	531,273	524,463	557,045	31
32	Rate Base	5,562,404	6,158,482	6,626,022	7,244,388	32

APPENDIX B: Table 1-C

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Adopted Results of Operations at Proposed Rates

Electric Generation Summary

(Thousands of Dollars)

Line No.	Description	Adj Recorded Year 2017RA (B)	Estimated Year 2018 (C)	Estimated Year 2019 (D)	Test Year 2020 (E)	Line No.
	REVENUE:					
1	Revenue Collected in Rates	2,110,409	2,101,047	2,190,921	2,289,345	1
2	Plus Other Operating Revenue	6,037	6,037	6,037	8,755	2
3	Total Operating Revenue	2,116,446	2,107,084	2,196,958	2,298,100	3
	OPERATING EXPENSES:					
4	Energy Costs	0	0	0	0	4
5	Production / Procurement	643,695	605,576	635,273	623,520	5
6	Storage	0	0	0	0	6
7	Transmission	7,647	8,918	7,876	8,027	7
8	Distribution	0	0	0	0	8
9	Customer Accounts	4,259	3,596	3,310	3,475	9
10	Uncollectibles	7,154	7,194	7,413	7,475	10
11	Customer Services	0	594	547	574	11
12	Administrative and General	301,176	329,184	376,552	359,509	12
13	Franchise & SFGR Tax Requirement	16,032	16,255	16,949	17,731	13
14	Amortization	176	174	172	23,271	14
15	Wage Change Impacts	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	16
17	Other Adjustments	(20,000)	(20,000)	(20,000)	(14,445)	17
18	Subtotal Expenses:	960,140	951,490	1,028,092	1,029,136	18
	TAXES:					
19	Superfund	0	0	0	0	19
20	Property	57,039	60,180	62,209	62,896	20
21	Payroll	31,324	29,365	31,725	30,890	21
22	Business	318	328	339	350	22
23	Other	1,958	3,094	3,930	4,003	23
24	State Corporation Franchise	19,389	19,071	28,045	42,970	24
25	Federal Income	79,188	1,912	9,827	29,937	25
26	Total Taxes	189,217	113,950	136,075	171,046	26
27	Depreciation	505,701	549,512	583,860	659,413	27
28	Fossil/Hydro Decommissioning	(5,527)	(5,527)	(5,527)	23,259	28
29	Nuclear Decommissioning	0	0	0	0	29
30	Total Operating Expenses	1,649,530	1,609,424	1,742,500	1,882,854	30
31	Net for Return	466,916	497,660	454,459	415,246	31
32	Rate Base	5,242,238	5,364,793	5,320,848	5,400,521	32

APPENDIX C
Pacific Gas and Electric Company
2020 CPUC General Rate Case (GRC)
Decision Tables - Revenue Requirement Comparison (Test Year 2020)

APPENDIX C

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Decision Tables - Revenue Requirement Comparison (Test Year 2020)

TABLE INDEX

APPENDIX C: Table 1
Pacific Gas and Electric Company
2020 CPUC General Rate Case (GRC) - Line of Business (LOB) Position Summary
LOB Summary of Adopted Increase Over Authorized 2019 General Rate Case
(Millions of Dollars)

			Settlement		Adopted			
Line		1/1/2020 Authorized (Note 1)	2020 Proposed	Difference from Authorized	2020 Proposed	Difference from Authorized	Difference from Settlement	Line
		(a)	(b)	(c)=(b-a)	(d)	(e)=(d)-(a)	(f)=(e)-(c)	
	Electric Distribution							
1	Operation and Maintenance	809	1,060	250	1,060	250	0	1
2	Customer Services	214	153	(61)	153	(61)	0	2
3	Administrative & General	399	530	131	530	131	0	3
4	Less: Revenue Credits (OORs & Wheeling)	(118)	(159)	(41)	(159)	(41)	0	4
5	RF&U, Other Adjs, Taxes Other than Income	86	107	21	107	21	0	5
6	Taxes: Income and Property	324	330	6	330	6	0	6
7	Depreciation, Decommission and Amortization	1,499	1,498	(1)	1,498	(1)	0	7
8	Return	1,151	1,281	130	1,281	130	0	8
9	Retail Revenue Requirement	4,364	4,800	436	4,800	436	0	9
	Gas Distribution							
10	Operation and Maintenance	395	382	(13)	382	(13)	0	10
11	Customer Services	121	120	(1)	120	(1)	0	11
12	Administrative & General	270	314	44	314	44	0	12
13	Less: Revenue Credits (OORs & Wheeling)	(28)	(27)	1	(27)	1	0	13
14	RF&U, Other Adjs, Taxes Other than Income	55	61	6	61	6	0	14
15	Taxes: Income and Property	83	99	16	99	16	0	15
16	Depreciation, Decommission and Amortization	558	508	(50)	508	(50)	0	16
17	Return	508	557	49	557	49	0	17
18	Retail Revenue Requirement	1,963	2,013	51	2,013	51	0	18
	Electric Generation							
19	Operation and Maintenance	741	632	(109)	632	(109)	0	19
20	Customer Services	3	4	1	4	1	0	20
21	Administrative & General	284	360	75	360	75	0	21
22	Less: Revenue Credits (OORs & Wheeling)	(6)	(9)	(3)	(9)	(3)	0	22
23	RF&U, Other Adjs, Taxes Other than Income	40	46	6	46	6	0	23
24	Taxes: Income and Property	82	136	54	136	54	0	24
25	Depreciation, Decommission and Amortization	620	706	86	706	86	0	25
26	Return	428	415	(13)	415	(13)	0	26
27	Retail Revenue Requirement	2,191	2,289	98	2,289	98	0	27
	Total General Rate Case							0
28	Operation and Maintenance	1,946	2,073	128	2,073	128	0	28
29	Customer Services	338	277	(61)	277	(61)	0	29
30	Administrative & General	953	1,203	250	1,203	250	0	30
31	Less: Revenue Credits (OORs & Wheeling)	(152)	(195)	(42)	(195)	(42)	0	31
32	RF&U, Other Adjs, Taxes Other than Income	181	214	33	214	33	0	32
33	Taxes: Income and Property	488	565	77	565	77	0	33
34	Depreciation, Decommission and Amortization	2,677	2,712	35	2,712	35	0	34
35	Return	2,087	2,253	167	2,253	167	0	35
36	Retail Revenue Requirement	8,518	9,102	585	9,102	585	0	36

Note 1: These amounts include adopted revenues from PG&E's 2017 GRC Decision 17-05-013, adjusted for the Tax Cuts and Job Act of 2017. Also included are:
- The Diablo Canyon Seismic Studies Long Term Seismic Program (LTSP) expenses,
- Residential Rate Reform expenses for Time of Use (TOU) Default Pilots Default TOU Rates, Marketing, Education and Outreach, and implementation of other requirements required by D.15-07-001 and R.12-06-013 and related proceedings,
- Natural Gas Leak Abatement Program Gas Distribution expense and capital costs, pursuant to CPUC Decision 17-06-015 (Ordering Paragraph 12),
- Mobile Home Park to and beyond the meter capital costs recorded through 12/31/17, pursuant to CPUC Decision 14-03-021 (Ordering Paragraph 8).

APPENDIX C: Table 2
Pacific Gas and Electric Company
2020 CPUC General Rate Case (GRC) - Position Summary
Results Of Operations Summary of Adopted Increase Over Authorized 2019 General Rate Case
Results of Operations - Test Year 2020
(Millions of Dollars)

Line No.	Description	1/1/2020 Authorized *(Note 1)*	Settlement 2020 Proposed	Settlement Difference from Authorized	Adopted 2020 Proposed	Adopted Difference from Authorized	Difference from Settlement	Line No.
		(a)	(b)	(c)=(b-a)	(d)	(e)=(d)-(a)	(f)=(e)-(c)	
	REVENUE:							
1	Revenue Collected in Rates	8,518	9,102	585	9,102	585	0	1
2	Plus Other Operating Revenue	152	195	42	195	42	0	2
3	Total Operating Revenue	8,670	9,297	627	9,297	627	0	3
	OPERATING EXPENSES:	3,237						
4	Energy Costs	0	0	0	0	0	0	4
5	Production	737	626	(111)	626	(111)	0	5
6	Storage	0	0	0	0	0	0	6
7	Transmission	8	10	2	10	2	0	7
8	Distribution	1,201	1,438	237	1,438	237	0	8
9	Customer Accounts	297	246	(52)	246	(52)	0	9
10	Uncollectibles	30	30	(0)	30	(0)	0	10
11	Customer Services	41	31	(10)	31	(10)	0	11
12	Administrative and General	953	1,203	250	1,203	250	0	12
13	Franchise Requirements	70	76	6	76	6	0	13
14	Amortization	0	23	23	23	23	0	14
15	Wage Change Impacts	0	0	0	0	0	0	15
16	Other Price Change Impacts	0	0	0	0	0	0	16
17	Other Adjustments	(30)	(2)	28	(2)	28	0	17
18	Subtotal Expenses:	3,307	3,680	373	3,680	373	0	18
	TAXES:							
19	Superfund	0	0	0	0	0	0	19
20	Property	304	350	46	350	46	0	20
21	Payroll	107	96	(12)	96	(12)	0	21
22	Business	1	1	0	1	0	0	22
23	Other	3	14	11	14	11	0	23
24	State Corporation Franchise	96	117	21	117	21	0	24
25	Federal Income	88	97	9	97	9	0	25
26	Total Taxes	599	676	76	676	76	0	26
27	Depreciation	2,674	2,665	(9)	2,665	(9)	0	27
28	Fossil Decommissioning	3	23	20	23	20	0	28
29	Nuclear Decommissioning	0	0	0	0	0	0	29
30	Total Operating Expenses	6,583	7,044	461	7,044	461	0	30
31	Net for Return	2,087	2,253	167	2,253	167	0	31
32	Rate Base	27,276	29,463	2,186	29,463	2,186	0	32

Note 1: These amounts include adopted revenues from PG&E's 2017 GRC Decision 17-05-013, adjusted for the Tax Cuts and Job Act of 2017. Also included are:
- The Diablo Canyon Seismic Studies Long Term Seismic Program (LTSP) expenses,
- Residential Rate Reform expenses for Time of Use (TOU) Default Pilots Default TOU Rates, Marketing, Education and Outreach, and implementation of other requirements required by D.15-07-001 and R.12-06-013 and related proceedings,
- Natural Gas Leak Abatement Program Gas Distribution expense and capital costs, pursuant to CPUC Decision 17-06-015 (Ordering Paragraph 12),
- Mobile Home Park to and beyond the meter capital costs recorded through 12/31/17, pursuant to CPUC Decision 14-03-021 (Ordering Paragraph 8).

APPENDIX D

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Decision Tables – Ratebase (Test Year 2020)

APPENDIX D

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Decision Tables - Ratebase (Test Year 2020)

TABLE INDEX

APPENDIX D: Table 1

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Adopted Rate Base

Electric and Gas Departments Summary

(Thousands of Dollars)

Line No.	Description	Recorded Year 2017 (A)	Adj Recorded Year 2017RA (B)	Estimated Year 2018 (C)	Estimated Year 2019 (D)	Test Year 2020 (E)	Line No.
	WEIGHTED AVERAGE PLANT:						
1	Plant Beginning Of Year (BOY)	58,069,604	58,069,604	59,505,286	62,583,248	65,805,929	1
2	Net Additions	0	0	1,383,125	1,451,958	1,538,234	2
3	Total Weighted Average Plant	58,069,604	58,069,604	60,888,411	64,035,206	67,344,163	3
	WORKING CAPITAL:						
4	Material and Supplies - Fuel	60	60	0	0	0	4
5	Material and Supplies - Other	469,233	469,233	470,352	283,387	261,614	5
6	Working Cash	538,005	538,005	669,130	679,411	741,122	6
7	Total Working Capital	1,007,297	1,007,297	1,139,482	962,798	1,002,736	7
	ADJUSTMENTS FOR TAX REFORM ACT:						
8	Deferred Capitalized Interest	15,028	15,028	13,771	15,609	17,076	8
9	Deferred Vacation	38,948	38,948	33,144	27,959	28,871	9
10	Deferred CIAC Tax Effects	514,384	514,384	509,148	487,564	475,666	10
11	Total Adjustments	568,360	568,360	556,064	531,131	521,613	11
12	CUSTOMER ADVANCES	77,259	77,259	77,416	77,259	77,259	12
	DEFERRED TAXES						
13	Accumulated Regulatory Assets	(15,478)	(15,478)	(14,338)	(13,206)	(12,083)	13
14	Accumulated Fixed Assets	5,057,014	5,057,014	5,193,206	5,062,710	4,795,000	14
15	Accumulated Other	0	0	0	0	0	15
16	Deferred ITC	239,991	239,991	229,421	218,852	208,283	16
17	Deferred Tax - Other	0	0	0	0	0	17
18	Total Deferred Taxes	5,281,528	5,281,528	5,408,290	5,268,355	4,991,200	18
19	DEPRECIATION RESERVE	29,076,508	29,076,508	30,627,329	32,438,498	34,337,542	19
20	TOTAL Ratebase	25,209,967	25,209,967	26,470,922	27,745,023	29,462,512	20

APPENDIX D: Table 1-A

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Adopted Rate Base

Electric Distribution Summary

(Thousands of Dollars)

Line No.	Description	Recorded Year 2017 (A)	Adj Recorded Year 2017RA (B)	Estimated Year 2018 (C)	Estimated Year 2019 (D)	Test Year 2020 (E)	Line No.
	WEIGHTED AVERAGE PLANT:						
1	Plant Beginning Of Year (BOY)	30,413,374	30,413,374	31,156,994	32,888,831	34,845,772	1
2	Net Additions	0	0	780,041	916,444	915,573	2
3	Total Weighted Average Plant	30,413,374	30,413,374	31,937,035	33,805,276	35,761,345	3
	WORKING CAPITAL:						
4	Material and Supplies - Fuel	0	0	0	0	0	4
5	Material and Supplies - Other	96,120	96,120	106,083	106,887	99,848	5
6	Working Cash	251,806	251,806	336,367	335,785	335,577	6
7	Total Working Capital	347,926	347,926	442,450	442,671	435,425	7
	ADJUSTMENTS FOR TAX REFORM ACT:						
8	Deferred Capitalized Interest	(6,747)	(6,747)	(6,822)	(5,054)	(3,457)	8
9	Deferred Vacation	17,469	17,469	14,866	12,540	12,949	9
10	Deferred CIAC Tax Effects	388,543	388,543	388,336	374,623	368,689	10
11	Total Adjustments	399,265	399,265	396,380	382,109	378,181	11
12	CUSTOMER ADVANCES	63,714	63,714	63,926	63,714	63,714	12
	DEFERRED TAXES						
13	Accumulated Regulatory Assets	0	0	0	0	0	13
14	Accumulated Fixed Assets	3,210,711	3,210,711	3,308,050	3,223,919	3,061,084	14
15	Accumulated Other	0	0	0	0	0	15
16	Deferred ITC	30,922	30,922	29,025	27,128	25,231	16
17	Deferred Tax - Other	0	0	0	0	0	17
18	Total Deferred Taxes	3,241,633	3,241,633	3,337,075	3,251,047	3,086,316	18
19	DEPRECIATION RESERVE	13,449,893	13,449,893	14,427,217	15,517,143	16,607,319	19
20	TOTAL Ratebase	14,405,326	14,405,326	14,947,646	15,798,153	16,817,603	20

APPENDIX D: Table 1-B

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Adopted Rate Base

Gas Distribution Summary

(Thousands of Dollars)

Line No.	Description	Recorded Year 2017 (A)	Adj Recorded Year 2017RA (B)	Estimated Year 2018 (C)	Estimated Year 2019 (D)	Test Year 2020 (E)	Line No.
	WEIGHTED AVERAGE PLANT:						
1	Plant Beginning Of Year (BOY)	11,645,171	11,645,171	12,130,996	13,114,890	14,066,425	1
2	Net Additions	0	0	458,415	453,858	450,398	2
3	Total Weighted Average Plant	11,645,171	11,645,171	12,589,412	13,568,748	14,516,823	3
	WORKING CAPITAL:						
4	Material and Supplies - Fuel	0	0	0	0	0	4
5	Material and Supplies - Other	187,624	187,624	171,646	32,822	24,578	5
6	Working Cash	122,971	122,971	142,685	146,771	168,687	6
7	Total Working Capital	310,595	310,595	314,331	179,593	193,265	7
	ADJUSTMENTS FOR TAX REFORM ACT:						
8	Deferred Capitalized Interest	(294)	(294)	(848)	(805)	(744)	8
9	Deferred Vacation	10,145	10,145	8,633	7,283	7,520	9
10	Deferred CIAC Tax Effects	125,475	125,475	120,447	112,588	106,630	10
11	Total Adjustments	135,326	135,326	128,233	119,066	113,406	11
12	CUSTOMER ADVANCES	13,545	13,545	13,490	13,545	13,545	12
	DEFERRED TAXES						
13	Accumulated Regulatory Assets	0	0	0	0	0	13
14	Accumulated Fixed Assets	800,228	800,228	847,228	845,203	815,711	14
15	Accumulated Other	0	0	0	0	0	15
16	Deferred ITC	15,447	15,447	14,685	13,922	13,160	16
17	Deferred Tax - Other	0	0	0	0	0	17
18	Total Deferred Taxes	815,675	815,675	861,913	859,125	828,871	18
19	DEPRECIATION RESERVE	5,699,468	5,699,468	5,998,090	6,368,715	6,736,691	19
20	TOTAL Ratebase	5,562,404	5,562,404	6,158,482	6,626,022	7,244,388	20

APPENDIX D: Table 1-C

Pacific Gas and Electric Company
2020 CPUC General Rate Case (GRC)
Adopted Rate Base
Electric Generation Summary
(Thousands of Dollars)

Line No.	Description	Recorded Year 2017 (A)	Adj Recorded Year 2017RA (B)	Estimated Year 2018 (C)	Estimated Year 2019 (D)	Test Year 2020 (E)	Line No.
	WEIGHTED AVERAGE PLANT:						
1	Plant Beginning Of Year (BOY)	16,011,059	16,011,059	16,217,296	16,579,526	16,893,732	1
2	Net Additions	0	0	144,669	81,656	172,262	2
3	Total Weighted Average Plant	16,011,059	16,011,059	16,361,964	16,661,182	17,065,994	3
	WORKING CAPITAL:						
4	Material and Supplies - Fuel	60	60	0	0	0	4
5	Material and Supplies - Other	185,489	185,489	192,624	143,678	137,188	5
6	Working Cash	163,228	163,228	190,078	196,856	236,858	6
7	Total Working Capital	348,776	348,776	382,702	340,534	374,047	7
	ADJUSTMENTS FOR TAX REFORM ACT:						
8	Deferred Capitalized Interest	22,069	22,069	21,441	21,467	21,277	8
9	Deferred Vacation	11,334	11,334	9,645	8,136	8,401	9
10	Deferred CIAC Tax Effects	366	366	366	353	347	10
11	Total Adjustments	33,768	33,768	31,451	29,956	30,026	11
12	CUSTOMER ADVANCES	0	0	0	0	0	12
	DEFERRED TAXES						
13	Accumulated Regulatory Assets	(15,478)	(15,478)	(14,338)	(13,206)	(12,083)	13
14	Accumulated Fixed Assets	1,046,075	1,046,075	1,037,928	993,588	918,205	14
15	Accumulated Other	0	0	0	0	0	15
16	Deferred ITC	193,622	193,622	185,712	177,802	169,892	16
17	Deferred Tax - Other	0	0	0	0	0	17
18	Total Deferred Taxes	1,224,219	1,224,219	1,209,302	1,158,183	1,076,013	18
19	DEPRECIATION RESERVE	9,927,146	9,927,146	10,202,022	10,552,640	10,993,533	19
20	TOTAL Ratebase	5,242,238	5,242,238	5,364,793	5,320,848	5,400,521	20

APPENDIX E

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Decision Tables – PTYR (2021- 2022)

APPENDIX E

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Decision Tables - PTYR (2021-2022)

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APPENDIX E: Table 1

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Adopted PTYR Results of Operations at Proposed Rates (2020-2022)

Electric and Gas Departments Summary

(Thousands of Dollars)

Line No.	Description	Test Year 2020	Attrition Year 2021 Increase	Attrition Year 2021 Total	Attrition Year 2022 Increase	Attrition Year 2022 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	9,102,470	338,509	9,440,980	344,217	9,785,197	1
2	Plus Other Operating Revenue	194,587	-	194,587	-	194,587	2
3	Total Operating Revenue	9,297,057	338,509	9,635,566	344,217	9,979,784	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production / Procurement	625,606	(8,993)	616,613	2,067	618,680	5
6	Storage	-	-	-	-	-	6
7	Transmission	9,986	198	10,184	75	10,259	7
8	Distribution	1,437,596	78,210	1,515,805	67,730	1,583,535	8
9	Customer Accounts	245,782	7,085	252,867	1,716	254,583	9
10	Uncollectibles	29,845	1,078	30,922	1,101	32,024	10
11	Customer Services	30,764	749	31,513	471	31,984	11
12	Administrative and General	1,203,064	29,670	1,232,734	20,129	1,252,864	12
13	Franchise & SFGR Tax Requireme	75,503	2,835	78,338	2,831	81,169	13
14	Amortization	23,271	-	23,271	-	23,271	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	(1,721)	(4,000)	(5,721)	(31,629)	(37,350)	17
18	Subtotal Expenses:	3,679,695	106,831	3,786,526	64,492	3,851,018	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	350,300	16,070	366,370	17,626	383,996	20
21	Payroll	95,862	3,135	98,997	-	98,997	21
22	Business	1,199	-	1,199	-	1,199	22
23	Other	13,723	-	13,723	-	13,723	23
24	State Corporation Franchise	117,148	(1,615)	115,533	2,631	118,164	24
25	Federal Income	97,424	(13,788)	83,635	5,624	89,260	25
26	Total Taxes	675,655	3,801	679,456	25,881	705,337	26
27	Depreciation	2,665,083	129,956	2,795,039	141,218	2,936,257	27
28	Fossil/Hydro Decommissioning	23,259	-	23,259	-	23,259	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	7,043,692	240,588	7,284,280	231,590	7,515,870	30
31	Net for Return	2,253,366	97,921	2,351,287	112,627	2,463,914	31
32	Rate Base	29,462,512	1,493,421	30,955,932	1,715,629	32,671,561	32

APPENDIX E: Table 1-A

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Adopted PTYR Results of Operations at Proposed Rates (2020-2022)

Electric Distribution Summary

(Thousands of Dollars)

Line No.	Description	Test Year 2020	Attrition Year 2021 Increase	Attrition Year 2021 Total	Attrition Year 2022 Increase	Attrition Year 2022 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	4,799,849	233,354	5,033,203	257,244	5,290,447	1
2	Plus Other Operating Revenue	158,665	-	158,665	-	158,665	2
3	Total Operating Revenue	4,958,514	233,354	5,191,868	257,244	5,449,113	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production / Procurement	-	-	-	-	-	5
6	Storage	-	-	-	-	-	6
7	Transmission	1,959	39	1,998	15	2,013	7
8	Distribution	1,057,769	67,888	1,125,657	64,051	1,189,707	8
9	Customer Accounts	138,328	3,992	142,320	957	143,277	9
10	Uncollectibles	16,128	759	16,887	837	17,723	10
11	Customer Services	14,417	361	14,778	203	14,981	11
12	Administrative and General	529,708	12,933	542,641	8,715	551,355	12
13	Franchise & SFGR Tax Requireme	38,258	1,800	40,059	1,985	42,043	13
14	Amortization	-	-	-	-	-	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	7,571	(2,000)	5,571	(12,510)	(6,939)	17
18	Subtotal Expenses:	1,804,138	85,773	1,889,910	64,251	1,954,161	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	206,535	9,213	215,748	9,760	225,508	20
21	Payroll	38,850	1,270	40,121	-	40,121	21
22	Business	537	-	537	-	537	22
23	Other	6,145	-	6,145	-	6,145	23
24	State Corporation Franchise	66,142	(864)	65,278	6,972	72,249	24
25	Federal Income	57,088	(9,380)	47,708	13,561	61,269	25
26	Total Taxes	375,296	240	375,536	30,293	405,829	26
27	Depreciation	1,498,006	82,360	1,580,366	87,770	1,668,135	27
28	Fossil/Hydro Decommissioning	-	-	-	-	-	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	3,677,439	168,372	3,845,812	182,314	4,028,125	30
31	Net for Return	1,281,075	64,982	1,346,057	74,931	1,420,987	31
32	Rate Base	16,817,603	1,063,708	17,881,311	1,224,305	19,105,616	32

APPENDIX E: Table 1-B

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Adopted PTYR Results of Operations at Proposed Rates (2020-2022)

Gas Distribution Summary

(Thousands of Dollars)

Line No.	Description	Test Year 2020	Attrition Year 2021 Increase	Attrition Year 2021 Total	Attrition Year 2022 Increase	Attrition Year 2022 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	2,013,276	120,704	2,133,980	94,785	2,228,765	1
2	Plus Other Operating Revenue	27,167	-	27,167	-	27,167	2
3	Total Operating Revenue	2,040,443	120,704	2,161,147	94,785	2,255,932	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production / Procurement	2,086	63	2,149	2	2,151	5
6	Storage	-	-	-	-	-	6
7	Transmission	-	-	-	-	-	7
8	Distribution	379,827	10,322	390,149	3,679	393,828	8
9	Customer Accounts	103,980	2,998	106,978	724	107,702	9
10	Uncollectibles	6,242	369	6,611	290	6,901	10
11	Customer Services	15,773	374	16,147	260	16,406	11
12	Administrative and General	313,847	7,795	321,642	5,299	326,941	12
13	Franchise & SFGR Tax Requireme	19,513	1,154	20,668	906	21,574	13
14	Amortization	-	-	-	-	-	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	5,153	(1,000)	4,153	(9,075)	(4,922)	17
18	Subtotal Expenses:	846,421	22,075	868,496	2,086	870,582	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	80,869	5,627	86,496	6,389	92,885	20
21	Payroll	26,122	854	26,976	-	26,976	21
22	Business	312	-	312	-	312	22
23	Other	3,574	-	3,574	-	3,574	23
24	State Corporation Franchise	8,037	1,735	9,771	(3,830)	5,942	24
25	Federal Income	10,399	5,917	16,316	(7,268)	9,048	25
26	Total Taxes	129,313	14,133	143,446	(4,709)	138,737	26
27	Depreciation	507,664	34,680	542,344	39,241	581,585	27
28	Fossil/Hydro Decommissioning	-	-	-	-	-	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	1,483,398	70,888	1,554,286	36,618	1,590,904	30
31	Net for Return	557,045	49,816	606,861	58,166	665,028	31
32	Rate Base	7,244,388	648,457	7,892,845	756,926	8,649,771	32

APPENDIX E: Table 1-C

Pacific Gas and Electric Company

2020 CPUC General Rate Case (GRC)

Adopted PTYR Results of Operations at Proposed Rates (2020-2022)

Electric Generation Summary

(Thousands of Dollars)

Line No.	Description	Test Year 2020	Attrition Year 2021 Increase	Attrition Year 2021 Total	Attrition Year 2022 Increase	Attrition Year 2022 Total	Line No.
		(A)	(B)	(C)	(D)	(E)	
	REVENUE:						
1	Revenue Collected in Rates	2,289,345	(15,549)	2,273,796	(7,812)	2,265,985	1
2	Plus Other Operating Revenue	8,755	-	8,755	-	8,755	2
3	Total Operating Revenue	2,298,100	(15,549)	2,282,551	(7,812)	2,274,739	3
	OPERATING EXPENSES:						
4	Energy Costs	-	-	-	-	-	4
5	Production / Procurement	623,520	(9,057)	614,463	2,066	616,529	5
6	Storage	-	-	-	-	-	6
7	Transmission	8,027	159	8,187	60	8,246	7
8	Distribution	-	-	-	-	-	8
9	Customer Accounts	3,475	95	3,569	35	3,604	9
10	Uncollectibles	7,475	(51)	7,424	(25)	7,399	10
11	Customer Services	574	14	588	9	597	11
12	Administrative and General	359,509	8,943	368,452	6,116	374,568	12
13	Franchise & SFGR Tax Requireme	17,731	(120)	17,611	(60)	17,551	13
14	Amortization	23,271	-	23,271	-	23,271	14
15	Wage Change Impacts	-	-	-	-	-	15
16	Other Price Change Impacts	-	-	-	-	-	16
17	Other Adjustments	(14,445)	(1,000)	(15,445)	(10,044)	(25,489)	17
18	Subtotal Expenses:	1,029,136	(1,017)	1,028,120	(1,845)	1,026,274	18
	TAXES:						
19	Superfund	-	-	-	-	-	19
20	Property	62,896	1,229	64,126	1,477	65,603	20
21	Payroll	30,890	1,010	31,900	-	31,900	21
22	Business	350	-	350	-	350	22
23	Other	4,003	-	4,003	-	4,003	23
24	State Corporation Franchise	42,970	(2,486)	40,483	(511)	39,972	24
25	Federal Income	29,937	(10,325)	19,612	(669)	18,943	25
26	Total Taxes	171,046	(10,572)	160,474	297	160,771	26
27	Depreciation	659,413	12,917	672,330	14,207	686,536	27
28	Fossil/Hydro Decommissioning	23,259	-	23,259	-	23,259	28
29	Nuclear Decommissioning	-	-	-	-	-	29
30	Total Operating Expenses	1,882,854	1,328	1,884,182	12,658	1,896,841	30
31	Net for Return	415,246	(16,877)	398,369	(20,470)	377,899	31
32	Rate Base	5,400,521	(218,745)	5,181,776	(265,602)	4,916,173	32