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Decision 17-05-013 May 11, 2017

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, 2017 (U39M).	Application 15-09-001 (Filed September 1, 2015)

DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S GENERAL RATE CASE REVENUE REQUIREMENT FOR 2017-2019

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DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S GENERAL RATE CASE REVENUE REQUIREMENT FOR 2017-2019

Summary

This Decision addresses a comprehensive Settlement Agreement between all active parties in this proceeding, Pacific Gas and Electric Company's (PG&E) test year 2017 General Rate Case. As filed, the Settlement Agreement resolved all but two contested issues. The Settlement Agreement is approved, with two modifications of provisions of the Settlement Agreement that are found to be either not reasonable in light of the whole record, not consistent with law, or not in the public interest. The two contested issues are also resolved.

PG&E is authorized a General Rate Case (GRC) revenue requirement increase for 2017 of $88 million over its currently authorized level of $7.916 billion, a 1.1% increase. This authorized increase is the net result of a decrease from 2016 levels of $62 million for electric distribution, a decrease of $3 million for gas distribution, and an increase of $153 million for electric generation. The Commission also authorizes post-test year revenue requirement increases of $444 million in 2018 (an annual increase of 5.5%), and $361 million in 2019 (an annual increase of 4.3%).

With these specified exceptions, the Settlement Agreement attached to the Settlement Motion is adopted:

- Section 3.1.3 (Electric Distribution) PG&E shall establish a Rule 20A balancing account that tracks the annual capital and expense costs for Rule 20A undergrounding projects, on a forecast and recorded basis. In addition, PG&E, the City of Hayward, and Commission staff are directed to determine a joint estimate of the scope and funding required for an audit of PG&E's Rule 20A program.

- Section 3.1.5.2 of the Settlement Agreement, as reflected in the Settling Parties' April 24, 2017 proposed alternative provisions, is adopted. PG&E shall file a standalone application for recovery of recorded costs in its Residential Rates Reform Memorandum Account, or shall seek recovery in Commission Rulemaking 12-06-013.
- Section 3.1.9.3 of the Settlement Agreement is not adopted. Instead PG&E shall file an advice letter to establish a two-way tax memorandum account in the form described in this decision.

PG&E's total authorized 2017 revenue requirements for its gas distribution, electric distribution, and electric generation lines of business are $1.738 billion, $4.151 billion, and $2.115 billion, respectively, a total of $8.004 billion. This authorized revenue requirement reflects our careful assessment of the 2017 base revenue requirement that is necessary for PG&E to provide safe and reliable service. Appendix A of this decision contains the Results of Operations table for PG&E, which incorporates the forecasted costs we find to be reasonable, and which are adopted in today's decision. The adopted 2017 revenue requirements shall become effective upon filing of tariffs pursuant to the directives of this decision.[1]

This proceeding remains open.

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[1] Decision (D.) 16-03-009 granted PG&E's unopposed motion, filed December 18, 2015, seeking an order to make its 2017 test year GRC revenue requirement effective as of January 1, 2017, even in the event the Commission issues a final decision after that date. Pursuant to D.16-03-009 PG&E may recover interest on the new revenue requirement (based on a Federal Reserve three-month commercial paper rate) during the period before its inclusion in customer rates.

The revenue requirement increases that we adopt herein reflect our major findings regarding PG&E's proposals and the settled-upon outcomes, as summarized below.

Settlement and Joint Proposals

The major overall outcome of our decision today is our finding that, with several specified exceptions, the comprehensive Settlement Agreement entered into by PG&E and the other Settling Parties is reasonable, consistent with the law and in the public interest. Our finding is based on our examination of the original positions of the parties, and comparing those to the amounts, methodologies, and other agreements set forth in the Settlement Agreement. The revenue requirements provided for in the Settlement Agreement will provide the necessary funds to allow PG&E to operate its electric distribution system, gas distribution system, and its electric generation assets safely and reliably at reasonable rates. The authorizations adopted in this decision are made pursuant to applicable statutory divisions of the Public Utilities Code, the Commission's Rules of Practice and Procedure, and prior decisions, orders, and resolutions of the Commission.

In approving the overall Settlement Agreement, we also endorse two separate agreements between PG&E and two parties in this proceeding. These Memorandums of Understanding (MOUs) are intended to avoid unnecessary litigation on issues of common interest between the parties:

> Center for Accessible Technology: In its opening testimony, PG&E presented a MOU reached with the Center for Accessible Technology. The MOU is intended to improve accessibility issues for PG&E's disabled customers.
>
> Small Business Utility Advocates: PG&E also presented a MOU reached with the Small Business Utility Advocates to

improve various aspects of PG&E's service to small businesses in its opening testimony.

With respect to the overall Settlement Agreement, we provide an overview here of the more significant investments and activities that will be funded by the revenue requirements that we authorize today. We then turn to our detailed review and analysis of the merits of each area of the Settlement Agreement.

Gas Distribution

Our adopted gas distribution revenue requirement includes additional funding to enable PG&E to continue to upgrade its aging pipeline system and to improve its emergency response capabilities. There are several explanations for the 2017 cost increases in this area.

First, in the category of leak survey and repair, PG&E will receive additional funding to transition from a 5-year to a 4-year leak survey cycle, to expand use of new surveyor technology, and to repair below-ground leaks.

Second, in the category of corrosion control, PG&E will receive additional funding for new and replacement cathodic-protection systems and remote monitoring systems.

Third, PG&E will receive additional funding for gas pipeline replacement and reliability, especially its Gas Pipeline Replacement Program where PG&E requested sufficient revenues to replace 46 miles of pipe per year, 95 miles of Aldyl-A plastic pipe per year, and 15 miles gas mains per year, and to install additional emergency valves (the Settlement Agreement may alter these exact values).

Electric Distribution

Our adopted electric distribution revenue requirement includes additional funding to enable PG&E to continue to invest in enhancing grid capabilities and ongoing emergency preparedness and response activities. There are several explanations for the 2017 cost increases in this area.

First, PG&E will continue to invest in its electric distribution system to support growth in customer connections and related investments for underground assets, substations and system reliability by replacing aged equipment. A related area involves investments in grid modernization with circuit upgrades, protection upgrades, and additional capacity increases to support distributed generation resources.

Second, PG&E will receive additional funds for activities related to safety, maintenance and compliance with Commission requirements in areas such as its LED streetlight replacement program, vegetation management and pole asset management.

Third, PG&E will receive additional funds for emergency preparedness and response activities such as upgrading its Emergency Centers. The purpose of these additional investments is to ensure the utility's readiness for major earthquakes and other events that could cause significant disruptions in service.

Energy Supply

Our adopted energy supply revenue requirement includes additional funding in 2017 to enable PG&E to further improve safety, operational and environmental performance of its company-owned electric generation assets. The funding is intended to support PG&E's efforts to manage what it describes as the operational challenges of integrating increasing volumes of intermittent energy resources onto the grid, improving asset management programs, and implementing Federal Energy Regulatory Commission license conditions, such as facility modifications to increase water flows. On the other hand, PG&E's capital spending in the energy supply area will decrease due to PG&E's

multi-year plan to reduce capital spending at Diablo Canyon Power Plant, where many large projects have been completed or are nearing completion.

Customer Care

Our adopted Customer Care revenue requirement includes additional funding in 2017 to enable PG&E to improve its capability to meet what it describes as increased service needs through a number of new initiatives.

First, PG&E will receive additional funding for improved account services for its agricultural customers, small business customers (pursuant to the MOU with Small Business Utility Advocates described above), and large commercial/industrial customers; to better coordinate with local communities regarding PG&E projects and services; to manage increased billing operations due to expanding Community Choice Aggregation programs providing service in PG&E's territory; and to manage increased enrollment growth and billing exceptions for the Commission's Net Energy Metering program and time of use rates.

Second, PG&E will make additional investments in its SmartMeter program, purchasing new meters where required and upgrading and optimizing its SmartMeter communication network to improve coverage and reliability.

Some of these authorized spending increases will be offset in 2017 by areas where PG&E requested less funds than it is currently authorized, such as for manual meter reading expenses and reduced budgets for information technology projects.

Shared Services

Our adopted Shared Services revenue requirement includes additional funding in 2017 to enable PG&E to implement several initiatives that affect the company as a whole. PG&E describes these expenditures as necessary to build on progress made during the last three years since its previous GRC. For example, PG&E will continue to implement safety initiatives to strengthen its safety culture, including a peer-to-peer observation program and the expansion of its Contractor Safety program. PG&E also intends to expand implementation of its Enterprise Records and Information Management project, which will centralize and standardize records and information management activities.

We also authorize funding related to PG&E's management of its real estate assets, including funding to reduce and optimize office space square footage throughout its service territory, and to work on its Service Centers to optimize the number of locations and the layout of facilities.

Some of these authorized spending increases will be offset in 2017 by PG&E's reduced transportation services budget, as certain compliance expenses are reduced.

Information Technology

Our adopted Information Technology (IT) revenue requirement includes additional funding in 2017 to enable PG&E to further improve its IT-related services by investing in additional technology to facilitate the convergence of digital technology and utility operations, such that PG&E becomes what it describes as a "Digital Utility." The authorized expenditures and new investments are intended to help PG&E maintain reliability and support the Digital Utility, including investments in its telecommunications network, IT operational continuity and data center disaster recovery capabilities, and enhancements in system and information cybersecurity. Other expenditures and investments are intended to support and enable new business technology solutions requested by PG&E's operating and supporting lines of business.

1. Procedural Background

In Phase 1 of a General Rate Case (GRC) proceeding, the Commission determines the utility applicant's gas and electric system revenue requirements necessary for the utility to recover the capital investments and annual operations and maintenance expenses at the core of the utilities operations. Phase 2 of the GRC is the subject of a separate application, and addresses the electric marginal cost, revenue allocation, and rate design matters necessary to collect the Phase 1 costs from utility customers. Pacific Gas and Electric Company's (PG&E's) base revenue requirement (the subject of this GRC application) is only a portion of PG&E's total electric and gas revenue requirements, which include other large cost categories that are addressed by the Commission in additional, non-GRC proceedings (e.g., energy procurement costs and, for PG&E, its natural gas transmission and storage revenue requirement, a separate GRC-like proceeding).

1.1. PG&E's Application

In its Application filed September 1, 2015, PG&E sought authority to increase its base revenue requirements for its gas and electric distribution systems and electric generation by $457 million (an increase of 5.7%), effective January 1, 2017. This requested increase consisted of $85 million for its gas distribution system (a 4.9% increase), $164 million for its electric distribution system (a 3.9% increase) and $208 million for electric generation (a 10.6% increase). PG&E also requested additional Post-Test Year increases of approximately $489 million for 2018 (an additional 5.8% increase) and an additional $390 million for 2019 (an additional 4.4% increase).

Regarding the 2017 increases, PG&E provided these broad reasons for its requests:[2]

> Gas Distribution: The requested gas distribution revenue requirement of $1.8 billion reflects PG&E's forecast of costs it will incur in 2017 to safely own, operate, and improve its gas distribution system, as well as the costs of procuring natural gas for its core customers.
>
> Electric Distribution: The requested electric distribution revenue requirement of $4.4 billion reflects PG&E's forecast of costs it will incur in 2017 to safely own, operate and improve the electric distribution system, including the portion of the electric transmission system that provides service directly to end-use customers and to interconnect generation resources.
>
> Generation: The requested generation revenue requirement of $2.2 billion reflects PG&E's forecast of costs it will incur in 2017 to safely own, operate and improve its nuclear, hydroelectric, fossil, photovoltaic and fuel cell generation facilities, as well as to purchase electricity for its bundled service electric customers.
>
> PG&E also listed several specific drivers of its requested revenue increases:
>
> - Increases in the costs of delivering energy safely to customers and providing responsive customer service;
> - The need to make capital investments to replace aging infrastructure;
> - The need for capacity-driven additions;
> - Recovery of costs for depreciation associated with PG&E's plant investments; and

[2] Exhibit PG&E-1 at 5-6, footnotes omitted.

- Costs of complying with governmental regulations and orders.

PG&E modified and lowered its original request in its rebuttal testimony, served on May 27, 2016. In its revised request, PG&E sought authority to increase its base revenue requirements by a total of $319 million instead of the$457 million that it requested in its September 2015 application, consisting of increases of $59 million for gas distribution, $67 million for electric distribution, and $193 million for electric generation.[3] The revised request represents a total increase of 4.0% over 2016 revenue requirements. PG&E also requested total post-test year increases of $467 million in 2018 (a 5.7% increase over 2017) and $368 million in 2019 (a 4.2% increase over 2018).

1.2. Further Procedural Developments

The initial prehearing conference was conducted on October 29, 2015. On December 1, 2016 the assigned Commissioner issued an "Assigned Commissioner's Ruling and Scoping Memo" setting the procedural schedule and addressing the scope of the proceeding and other procedural matters.

On March 7, 2016, the Commission's Safety and Enforcement Division (SED) Risk Assessment Section issued its Staff Report on the risk and safety aspects of PG&E's 2017 GRC. On March 25, 2016, SED staff hosted a workshop to discuss their report.

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[3] This request would result in 2017 base revenue requirements of $1.801 billion for gas distribution, $4.279 billion for electric distribution, and $2.155 billion for electric generation.

On April 8, 2016, the Commission's Office of Ratepayer Advocates (ORA) served its testimony and on April 29, 2016, the following intervenors served testimony:

- The Utility Reform Network (TURN)
- Alliance for Nuclear Responsibility (A4NR)
- Coalition of California Utility Employees (CUE)
- Collaborative Approaches to Utility Safety Enforcement (CAUSE)
- Consumer Federation of California (CFC)
- Environmental Defense Fund (EDF)
- Marin Clean Energy (MCE)
- Merced Irrigation District (Merced ID)
- Modesto Irrigation District (Modesto ID)
- National Diversity Coalition (NDC)
- Small Business Utility Advocates (SBUA)
- South San Joaquin Irrigation District (SSJID)

On May 26 and 27, 2016, PG&E, CUE, EDF and SSJID served rebuttal testimony.

In May 2016 and continuing during the months thereafter, parties engaged in settlement discussions. These discussions led to various extensions of the procedural schedule for this GRC.[4] Apart from the settlement discussions, International Brotherhood of Electrical Workers (IBEW), AFL-CIO, Local Union 1245 and PG&E reached a separate agreement on staffing issues as part of the collective bargaining process.

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[4] *See*, June 23, 2016 Assigned Commissioner's Ruling and Amended Scoping Memo.

On June 10, 2016, PG&E circulated a draft Joint Comparison Exhibit that provided a comparison of the revenue requirement positions of PG&E and the various parties.

In a development outside this proceeding that has impacted the outcome here, on June 20, 2016, PG&E, A4NR, CUE, Friends of the Earth, IBEW Local 1245, National Resources Defense Council, and Environment California entered a separate agreement known as the "Joint Proposal to Retire Diablo Canyon Nuclear Power Plant at the Expiration of the Current Operating Licenses and Replace it with a Portfolio of GHG-Free Resources" (Joint Proposal on Diablo Canyon).

1.3. Joint Motion for Adoption of Settlement Agreement

On July 21, 2016, pursuant to Rule 12.1(b) of Commission's Practice and Procedure (Rules), PG&E notified all parties on the service list for this proceeding of a settlement conference in order to discuss the terms of a possible settlement agreement.

The settlement conference took place on August 3, 2016. On the same day, following the settlement conference, the Settling Parties signed a Settlement Agreement and filed and served a Joint Motion for Adoption of Settlement Agreement (Joint Motion).[5] The Settling Parties are:

- PG&E
- ORA

[5] On August 3, 2016, the Settling Parties also filed a Joint Motion to Shorten Time for Comments and Replies to the Motion for Adoption of Settlement Agreement, and a Joint Motion for Admission of Testimony and Supporting Materials into the Evidentiary Record.

- TURN
- A4NR
- Center for Accessible Technology (CforAT)
- CUE
- CAUSE
- CFC
- EDF
- MCE
- Merced ID
- Modesto ID
- NDC
- SBUA
- SSJID

Also on August 3, 2016, PG&E filed, and served notice of the availability of, the Joint Comparison Exhibit (JCE), labeled Exhibit PG&E-37, Volumes 1 and 2. The Joint Comparison Exhibit supports the Settlement Agreement. As required by Rule 12.1(a), the Joint Comparison Exhibit provides information "indicating the impact of the settlement in relation to the utility's application and…in relation to the issues [Commission] staff contested, or would have contested, in a hearing."

Article 4 of the Settlement Agreement sets forth two contested issues over which the Settling Parties were unable to gain consensus. These issues concern: (i) a third post-test year and (ii) gas leak management. The Settling Parties proposed to present their respective positions on these contested issues through opening and reply comments on the Joint Motion. On August 10, 2016 the assigned Commissioner issued a second Amended Scoping Memo for this proceeding, modifying the schedule to provide a shortened comment period on the Joint Motion and the Settlement Agreement, and scheduling a public workshop on the Settlement Agreement as well as evidentiary hearings to review the Settlement Agreement.

On August 18, 2016 the following parties filed comments on the Settlement Agreement: PG&E, CUE and EDF (jointly on the second contested issue); ORA and PG&E (jointly on the first contested issue); CFC; and A4NR.

On August 25, 2016 the following parties filed reply comments on the Settlement Agreement: PG&E, CUE and EDF (jointly); ORA and PG&E (jointly on the first contested issue); and CFC.

A workshop to review the Settlement Agreement took place on August 30, 2016 (Settlement Workshop) and evidentiary hearings were held on September 1, 2016. The assigned Administrative Law Judge (ALJ) granted the joint motion for admission of testimony on September 1, 2016.

As explained below, a number of late-filed exhibits were filed following the Settlement Workshop and evidentiary hearings. These exhibits are listed below and are received into evidence:

Exhibit PG&E-38	"Summary of PG&E's 2017 GRC Settlement Agreement," (received into evidence September 3, 2016)
Exhibit PG&E-39	"Post Test-Year Ratemaking 2017 GRC," (received into evidence September 3, 2016)
Exhibit PG&E-40	"Pacific Gas and Electric Company Executive Compensation," (received into evidence September 3, 2016)
Exhibit PG&E-41	"Late-filed Exhibit on Test-year and Post Test-year Revenue Requirement," September 23, 2016

Exhibit PG&E-42	"Late-filed Exhibit on Rule 20A Project Spending Detail," October 3, 2016
Exhibit PG&E-43	"Late filed Exhibit on Executive Compensation and Safety," October 3, 2016
Exhibit PG&E-44	"Late-filed Exhibit on Safety-related Expenditures," October 10, 2016
Exhibit PG&E-45	"Late-filed Exhibit on SmartMeter Upgrade Cost Effectiveness," October 17, 2016
Exhibit PG&E-46	"Late Filed Exhibit on Calculation of Imputed Regulatory Values for the Post Test-Years," October 31, 2016

1.4. Public Participation Hearings and Correspondence from PG&E Ratepayers

In July, 2016, nineteen Public Participation Hearings (PPHs) were conducted by the assigned ALJ in eleven cities throughout PG&E's service territory: Bakersfield, Fresno, Stockton, Chico, Richmond, Oakland, San Francisco, Santa Rosa, San Bruno, San Jose, and San Luis Obispo. In addition to the ALJ, the Commission was represented by staff from the assigned Commissioner's office, its Public Advisor Office and its Business and Community Outreach Office. PG&E was represented at each hearing by an officer at the Vice President level, as well as staff with specialties that enabled them to provide one-on-one assistance to PG&E customers who raised service issues at the hearings. PG&E's officers spoke at the beginning of each PPH and engaged with other speakers throughout each hearing, responding to their specific questions about PG&E's operations and ensuring that those customers seeking specific assistance were helped, either at the PPH itself, or on a follow-up basis. We believe that the attendance by officers was well-received by other attendees and made for an overall more engaging experience for all concerned, and we commend PG&E for taking this step in this GRC.

The overall purpose of the PPHs is to provide a forum for the Commission to directly receive comments from PG&E's customers regarding the impact of the application on their personal circumstances. In addition, a number of letters and e-mails were sent to the Public Advisor's Office of the Commission concerning this GRC application.

The PPHs and written correspondence proved invaluable in affirming for this San Francisco-based Commission that its determination and authorization of PG&E's basic operating budget once every three years is no mere academic or accounting exercise. Rather, our decision today will affect the daily lives—and finances—of individuals, families, local governments, and small and large businesses throughout PG&E's vast territory. We take this responsibility seriously, and our decisions are influenced by the comments, opinions, and suggestions that we received from PG&E's customers up and down the state. These customers urged us to look closely at any requests for additional spending by PG&E.

In testimony supporting its September 2015 application, PG&E addressed California's ongoing economic recovery from the 2008 financial crisis, stating

> PG&E's service area is in expansion mode. Moody's Analytics describes PG&E's service area as "steadily expanding" and that its "outlook is bright." Consistent with this outlook, service sector growth is outpacing state and national averages, and manufacturing growth is accelerating. Unemployment rates are

> expected to decline through PG&E's 2017-2019 GRC period. Personal income is expected to increase.[6]

Nevertheless, PG&E also describes the results of a pre-GRC meeting held with a number of low-income minority groups in June 2015:

> At this meeting, PG&E and the participants discussed a number of challenges facing northern California, including high cost-of-living and home prices, high sales tax rates, and the drought. Further, it is understood that no two customers experience the economy the same way. Some will prosper while others could see their circumstances decline.[7]

PG&E concludes this overview by acknowledging that programs such as the California Alternate Rates for Energy and Family Electric Rate Assistance programs, as well as low-income energy efficiency programs, will continue to be necessary to help address the needs of financially disadvantaged customers in PG&E's territory.

The themes raised in PG&E's testimony were borne out again and again by individual ratepayers who spoke at the PPHs. One speaker described a neighbor who remained outdoors on hot summer evenings, unable to afford to run their air conditioner. Other speakers described significant investments in solar power or energy efficient windows and appliances, only to still find themselves challenged to pay their monthly PG&E bill. On the whole, speakers like these urged the Commission to do all it could to limit higher spending by PG&E.

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[6] Exhibit PG&E-1 at 1-7, citing Moody's Analytics, Report on PG&E's Service Territory (April 2015).

[7] *Ibid.*

Other speakers acknowledged the apparent need for the new investments described by PG&E, but urged the Commission to closely monitor PG&E's spending, to ensure that PG&E spends authorized funds for authorized purposes.

A significant number of speakers appeared to have benefited from direct technical or financial assistance from PG&E over the years, and attended the PPHs to tell their individual stories and express their appreciation to PG&E for that support. Many speakers also commended PG&E for its emergency response activities in areas of the state affected by wildfires in the last several years and urged the Commission to ensure that PG&E continues to receive adequate funding for these critical activities.

Finally, one of the more noteworthy aspects of the PPHs was the consistent attendance of local government officials at every location, all of whom expressed strong concern about proposals in this proceeding relating to PG&E's Commission-mandated program to "underground" what are currently overhead utility lines in communities throughout PG&E's service territory. Many of these officials also noted their concern regarding the Commission's treatment of the same undergrounding issue in PG&E's 2011 and 2014 GRCs. In response to the concerns expressed by these officials, approximately half the hearing time devoted to examination of the Settlement Agreement was devoted to this issue, and we have modified this area of the Settlement Agreement.

2. Safety

2.1. Background

The Commission is committed to safe utility operations, and we expect the utilities subject to our jurisdiction to make safety a foundational priority in everything they do. This commitment is reinforced by Section 451 of the Public

Utilities Code (Pub. Util. Code), which provides that every public utility shall "furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." This mandate has always guided the Commission's review of requests by utilities for increases in rates to support their investments in gas and electric infrastructure and other facilities.

In the years since the tragic explosion of PG&E's gas transmission pipeline in San Bruno on September 9, 2010, this Commission and the California Legislature have re-dedicated themselves to ensuring that the regulated utilities are operated in a safe manner and managed by executives who place safety at the top of their priorities while guiding their organizations. Much of this analysis and review has taken place in the GRC proceedings of PG&E and the other energy utilities subject to regulation by this Commission. In order to put today's decision into proper context, we briefly review that history and our progress below.

The GRCs of the large energy utilities have long been processed according to the Commission's Rate Case Plan (RCP), which establishes the minimum filing requirements and the procedural timelines for these proceedings. In the wake of the San Bruno tragedy, the Commission also opened several Rulemaking proceedings to evaluate the manner in which the regulated utilities consider safety and risk in their operations, and to mandate improvements in those practices. The results of these proceedings have supported the Commission's efforts to prioritize its consideration of safety and risk in GRC proceedings. First, new safety and reliability regulations for natural gas transmission and distribution pipelines, and related ratemaking mechanisms, were evaluated in

Rulemaking (R.) 11-02-019.[8] Second, the Commission evaluated the question of whether it should formalize rules to ensure the effective use of a risk-based decision-making framework to evaluate the safety and reliability improvements that are traditionally requested in GRC applications in R.13-11-006.[9] Third, the Commission opened an investigation on its own motion into the role of PG&E's board, executive governance, compensation, and the role of these high level activities at PG&E in producing a corporate culture in the years prior to the San Bruno tragedy that undercut safety in its operations.[10] The purpose of this investigation is to determine whether the organizational culture and corporate governance at PG&E and PG&E Corporation prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards.

In parallel to these Commission rulemakings and investigations, the Legislature also provided important guidance to the Commission regarding utility safety policies and actions. We explain below how the Commission incorporated this guidance into the proceedings listed above.

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[8] February 24, 2011, R.11-02-019, *Order Instituting Rulemaking on the Commission's Own Motion to Adopt New Safety and Reliability Regulations for Natural Gas Transmission and Distribution Pipelines and Related Ratemaking Mechanisms.*

[9] November 14, 2013, R.13-11-006, *Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the General Rate Case Plan for Energy Utilities.*

[10] August 27, 2015, Investigation 15-08-019, *Order Instituting Investigation on the Commission's Own Motion to Determine Whether Pacific Gas and Electric Company and PG&E Corporation's Organizational Culture and Governance Prioritize Safety.*

First, in October, 2011, Senate Bill (SB) 705 became law and added Sections 961 and 963 to the Public Utilities Code.[11] Section 963 declared that it is the policy of the state that the Commission and each gas utility place safety of the public and gas utility employees as the top priority, and that the Commission shall take all reasonable and appropriate actions necessary to carry out this safety priority policy, consistent with the principle of just and reasonable cost-based rates.[12] Section 961 directed each gas utility regulated by the Commission to develop a plan for the safe and reliable operation of its Commission-regulated gas pipeline facility that implements this policy, and directed the Commission to adopt these plans by December 31, 2012.[13]

Later, in September 2014 SB 900 became law.[14] Whereas SB 705 concerned only the natural gas utilities regulated by the Commission, SB 900 directed that the Commission shall develop formal procedures to consider safety in the rate case applications of both gas and electric utilities:[15]

> The procedures shall include a means by which safety information acquired by the commission through monitoring, data tracking and analysis, accident investigations, and audits of an applicant's safety programs may inform the commission's consideration of the application.

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[11] Statutes of 2011, Chapter 522.

[12] Pub. Util. Code § 963.

[13] Pub. Util. Code § 961(b)(1) and (2).

[14] Statutes of 2014, Chapter 552.

[15] Pub. Util. Code § 750.

In October, 2015 Assembly Bill (AB) 1266 became law and added Section 706 to the Public Utilities Code.[16] Pub. Util. Code § 706(b) provides as follows:

> For a five-year period following a triggering event, no electrical corporation or gas corporation shall recover expenses for excess compensation from ratepayers unless the utility complies with the requirements of this section and obtains the approval of the commission pursuant to this section.[17]

The Legislature directed the Commission to implement these provisions in GRC proceedings such as this one. Pub. Util. Code § 706(f) mandates that

> in every decision on a general rate case, [the Commission] shall require all authorized executive compensation to be placed in a balancing account, memorandum account, or other appropriate mechanism so that this section can be implemented without violating any prohibition on retroactive ratemaking.

This legislation supports our own recent expansion of our review of the utilities' executive compensation expense, and now requires us to consider an additional dimension: executive compensation as it is adjusted—or not adjusted—by the utilities after serious incidents that affect the safe and reliable

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16 Statutes of 2015, Chapter 599.

17 The terms in this Section are defined as follows:

> Pub. Util. Code § 706(a)(2) provides: "A 'triggering event' occurs if, after January 1, 2013, an electric corporation or gas corporation violates a federal or state safety regulation with respect to the plant and facility of the utility and, as a proximate cause of that violation, ratepayers incur a financial responsibility in excess of five million dollars ($5,000,000)."
>
> Pub. Util. Code § 706(a)(1) provides: "'Excess compensation' means any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of an electrical corporation or gas corporation that is in excess of one million dollars ($1,000,000)."

operation of utilities. The balancing account or memorandum account required by Pub. Util. Code § 706(f) will allow the Commission to review what was paid and awarded to officers of the utilities in the years after a triggering event, and to determine in a company's GRC application if any such monies paid should be refunded (or allowed to be recovered in rates).

2.2. Risk-Based Decision-Making in General Rate Cases

The Commission, acting on its own motion and incorporating this legislative guidance on an ongoing basis, took a significant step forward in R.13-11-006 when it issued Decision (D.) 14-12-025, its *Decision Incorporating a Risk-Based Decision-Making Framework into the Rate Case Plan.* In that decision, the Commission adopted extensive modifications to its RCP in order to explicitly incorporate a risk-based decision-making framework into the GRCs for the large energy utilities. The decision addressed the concern that formed the basis for the underlying rulemaking, namely that the utilities "may not explicitly or adequately address safety and reliability issues in their GRC filings …" because the appropriate filing requirements were not clearly stated in the existing RCP.

In its decision, the Commission found that the logical starting point for prioritizing safety for the investor-owned energy utilities is in the RCP and the GRCs of each of the energy utilities, because the GRC is the proceeding in which the utility requests the funding for the capital investments and annual operations and maintenance expenses that are essential to building and operating a safe and reliable utility. In order to adopt and develop a risk-based decision-making framework to evaluate safety improvements, the Commission modified the RCP by (1) establishing a Safety Model Assessment Proceeding (S-MAP) to allow the Commission and parties to examine, understand, and comment on the models that the energy utilities intended to use to explicitly prioritize and mitigate risks, and for the Commission to establish guidelines and standards for these models; and (2) establishing a new GRC phase as part of the RCP schedule: the "Risk Assessment and Mitigation Phase" (RAMP). This phase would begin with a utility filing no later than November 30 of the year before that utility files its GRC application. This phase is encompassed in a Commission Order Instituting Investigation, which allows parties and the Commission to review the utility's RAMP submission for consistency and compliance with its prior S-MAP, and to determine whether the elements contained in the RAMP submission can be used in the utility's subsequent GRC filing to support its position on the assessment of its safety risks and its plans to manage, mitigate, and minimize those risks, as expressed in the utility's actual GRC application.

As directed in D.14-12-025, the utilities filed their respective S-MAP applications in May 2015. The Commission reviewed the applications in a consolidated proceeding and issued its interim decision in D.16-08-018, directing the energy utilities to take steps to implement a more uniform risk management approach.[18] Based on the schedule of that proceeding, the first PG&E proceeding that will fully follow the new RCP will be the GRC application that is initiated with the filing of a RAMP in September 2017.

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[18] D.16-08-018, *Interim Decision Adopting the Multi-Attribute Approach (or Utility Equivalent Features) and Directing Utilities to Take Steps Toward a More Uniform Risk Management Framework.*

2.3. Transition to a Risk-Based Decision-Making Framework

During the interim period as the utilities transition to fully implementing the S-MAP and RAMP procedures, the Commission has taken steps to ensure that the utilities include more risk assessment analysis in support of their GRC applications. We review our progress in this area below.

First, in 2012 as part of PG&E's 2014 Test Year GRC application (Application (A.) 12-11-009), the Commission's Executive Director directed PG&E to perform a risk assessment of its gas and electric distribution systems and electric generation facilities, and to provide the risk assessments that formed the basis for PG&E's spending forecast. This resulted in the hiring of safety and risk assessment consultants by the SED, and the issuance of reports of their findings. In its decision addressing PG&E's application, the Commission took those reports into consideration as part of its evaluation of PG&E's funding requests.

In that decision, the Commission also approved several PG&E proposals intended to improve its showing on safety and risk in its 2017 GRC, the application before us today:[19]

- PG&E would provide additional testimony on its integrated planning process; affirmatively showing that risk management through integrated planning forms the foundation of the system safety and compliance projects and programs forecast in its 2017 GRC.

[19] D.14-08-032 at 12.

- PG&E would prioritize projects and programs in the 2017 GRC by using risk-based criteria and will demonstrate how the projects and programs it is forecasting mitigate the system safety risks listed on PG&E's risk registers.
- PG&E would provide enhanced testimony on its overall risk program from its Chief Risk Officer as well as Line of Business-specific risk testimony from the risk or asset management leads from Electric Operations, Energy Supply and Gas Operations.
- PG&E will use the proposed reporting procedures it has used throughout the 2014-2016 GRC cycle to account for its spending by Major Work Category, comparing authorized amounts to budgeted and spent amounts, and explaining significant differences.

Next, in 2014 in A.13-11-003, Southern California Edison Company's (SCE's) Test Year 2014 GRC application, an Assigned Commissioner's Ruling ordered the utility to file supplemental testimony regarding risk management and safety matters. After SCE served the required testimony SED served a report in response to SCE's testimony; that report was admitted into evidence and considered by the Commission in its decision on SCE's application.

Also in 2014, in D.14-12-025 the Commission directed that during the transition to fully implementing the S-MAP and RAMP procedures, as of February 1, 2015 all of the large energy utilities should include in all their future GRC applications thorough descriptions of the risk assessments and mitigation plans they plan to use in their GRC application filings.[20] The instant application by PG&E is the first to be filed since that requirement was put in place.

Finally, in July 2015, as part of A.14-11-003 and A.14-11-004, the Test Year 2016 GRC applications of San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCalGas), the assigned Commissioner introduced into the evidentiary record certain data obtained by the Commission's Energy Division regarding SDG&E's and SoCalGas' executive compensation, safety-related expenditures, natural gas capital expenditures and expenses, rate impacts, and electric distribution costs. Relying on this record material in its decision on the utilities' applications, the Commission required SDG&E and SoCalGas to include certain testimony in their next GRC filings and informed SDG&E, SoCalGas, and their corporate parent, Sempra Energy (Sempra), that their governance, safety record, and safety culture will inform the Commission's reasonableness review of their future GRCs, including the entirety of their requests for any compensation or benefits expenses.

2.4. The Proceeding Record Regarding Safety, and the Linkage between Safety and Executive Compensation

In this proceeding, the Commission builds on the recent history recited above and expands its consideration of safety matters in order to further document the linkage highlighted by the Legislature and the Commission between a utility's safety record and corporate governance.

[20] D.14-12-025 at 43 and Conclusion of Law 13.

The Public Utilities Code provides that Commission decisions shall contain separately stated findings of fact and conclusions of law on all issues material to the order or decision.[21] To provide for the necessary record on this matter, the December 1, 2015 Scoping Memo determined that this proceeding would consider whether PG&E's proposed risk management, safety culture, governance and policies, and investments will result in the safe and reliable operation of its facilities and services. The Scoping Memo also stated that this proceeding will document and review how PG&E finances safety efforts, particularly how the Commission evaluates compensation of PG&E's executive leadership around questions of safety. The Scoping Memo noted that the Commission has a significant tool at its disposal to ensure that the utility is operated in a safe and reliable manner: the alignment of the utility's financial interests with those of the public on safety matters. The assigned Commissioner and assigned ALJ took a number of steps to build this record.

First, the December 1, 2015 Scoping Memo directed SED to provide a report on safety and risk management aspects of PG&E's application in order to help the Commission identify whether and how PG&E is complying with the guidelines for risk management that were provided in D.14-12-025. SED completed its report on March 7, 2016, and the report was served on parties via a ruling of the assigned ALJ. The report described and analyzed how PG&E's existing process is evolving and is being used for the following purposes:[22]

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[21] Pub. Util. Code § 1705.

[22] *Staff Report on Pacific Gas and Electric Company 2017-2019 General Rate Case Application A.15-09-001*, at 5.

- to identify major risks;
- to determine potential mitigation plans and programs; and
- to inform PG&E's GRC budget requests in order to reduce or avoid those major risks.

Next, as directed in the March 7, 2016 ALJ ruling, SED conducted a workshop on March 25, 2016 in order to provide parties the opportunity to ask questions or seek clarifying information regarding its report. Also as provided in the ruling, ORA and other intervenors were afforded the opportunity to comment on the report in their direct testimony served on April 8 and April 29, 2016, respectively. PG&E had the opportunity to address the report and intervenor testimony in its own rebuttal testimony, served on May 27, 2016.

The record described above established a broad foundation for the Commission's review of the safety and risk management aspects of PG&E's application. However, because all but two contested issues in this proceeding were ultimately settled by all active parties, the "documentation and review" of how PG&E finances safety efforts that was anticipated in the Scoping Memo was not fully encompassed in parties' direct testimony and rebuttal testimony, in part because evidentiary hearings and post-hearing briefing were not necessary. For this reason, the intent of the Scoping Memo has been addressed by further developing the record at the August 30, 2016 Settlement Workshop and through several additional exhibits prepared and filed by PG&E.[23] As we highlight below, the Commission notes the cooperation of PG&E and the other Settling

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[23] The workshop was transcribed, and workshop handouts were entered into the record as Exhibits PG&E-38, PG&E-39, and PG&E-40.

Parties in making this record, beginning with their presentations and discussions at the Settlement Workshop, and continuing with the collaborative preparation and review of late-filed exhibits.

For example, one of the workshop panels covered "Safety, Risk, Integrated Planning and Executive Compensation." Under the heading of "accountability" the panel was asked to discuss whether, with respect to PG&E's spending on safety from the previous (Test Year 2014) GRC cycle, PG&E spent all of the previous GRC dollars forecasted for safety items. To supplement and document this discussion at the workshop, on October 10, 2016 PG&E also served Exhibit PG&E-44, "Safety Related Expenditures." The Exhibit provides additional details on PG&E's safety-related spending by summarizing actual and forecasted safety-related spending for the 2014-2016 period. The exhibit lists safety-related Work Categories with their respective authorized amounts and actual expenditures.

The workshop panel was also asked to discuss how the Commission can be assured that the assets underlying all of PG&E's GRC-related requests are currently operating in a completely safe state, and will be for the foreseeable future. Panelists responded by citing Section 3.2.8.2 of the Settlement Agreement, "Safe and Reliable Service":

> PG&E agrees that this Agreement should enable PG&E to comply with its obligations under Public Utilities Code Section 451 to "furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment and facilities…as are necessary to promote the safety, health, comfort and convenience of its patrons, employees, and the public."

Finally, under the heading of "Executive Compensation and Safety" the workshop panel was asked to discuss how the proposed settlement complies with the intent of the Scoping Memo that "this proceeding will document and review how PG&E finances safety efforts, particularly how the Commission evaluates compensation of PG&E's executive leadership around questions of safety." PG&E and other Settling Parties suggested that in order to provide additional clarity of the record, PG&E would work in collaboration with the other Settling Parties to prepare and serve Exhibit PG&E-43, "Late Filed Exhibit on Executive Compensation and Safety." That exhibit was filed on October 3, 2016 and provides additional documentation and explanation of PG&E's executive compensation plans and programs.

Based on the above and as discussed throughout the remainder of this decision, we believe that, taken together, we have a solid record upon which to base our decision on matters in this proceeding regarding PG&E's safety showing, as well as the linkage between safety and executive compensation. In sum, this record consists of PG&E's direct testimony, the SED report, the served testimony of the Settling Parties and other parties, the rebuttal testimony served by PG&E and other parties, the Settlement Workshop presentations and transcript, the Settlement Hearing testimony, and the late-filed exhibits described above.

3. The Settlement Agreement

The Commission has long favored the settlement of disputes. Article 12 of the Commission's Rules of Practice and Procedure (Rules) governs settlements and how the Commission reviews such agreements. Pursuant to Rule 12.1(d), the Commission will not approve a settlement, whether contested or uncontested, unless it is found to be reasonable in light of the whole record, consistent with law, and in the public interest. Rule 12.4 states that the Commission may reject a proposed settlement whenever it determines that the settlement is not in the public interest; the rule also provides remedies that may be pursued by settling parties in such an event.

In the August 3, 2016 Joint Motion, Settling Parties state that the principal public interest affected by this GRC is delivery of safe, reliable electric and gas service at reasonable rates and assert that the Settlement Agreement advances this interest because it sets forth a compromise that significantly reduces the revenue requirement originally sought by PG&E while providing the company with reasonable revenue requirement increases in 2017, 2018 and 2019.[24]

According to Settling Parties, the Settlement Agreement taken as a whole is reasonable in light of the entire record, consistent with the law, and in the public interest and thus meets the requirements of Rule 12.1(d).

First, the Settling Parties assert that the Settlement Agreement is reasonable in light of the record as a whole. The Settling Parties describe themselves as knowledgeable and experienced regarding the issues in this GRC proceeding, with a well-documented history of strongly-held positions, leading to different recommendations in many areas. With respect to the overall test year 2017 revenue requirement, Settling Parties cite the Joint Comparison Exhibit and suggest that it shows that the settled value falls within the ranges created by the Settling Parties' respective original positions. On this basis, Settling Parties suggest that the Settlement Agreement reflects a reasonable balance of the various interests affected in this proceeding.

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24 Joint Motion at 55.

Second, the Settling Parties assert that the Settlement Agreement is consistent with law, as well as prior Commission decisions: "the Settling Parties believe, and herein represent, that no term of the Settlement Agreement contravenes statutory provisions or prior Commission decisions. The Settling Parties are aware of no statutory provisions or controlling law that would be contravened or compromised by the Settlement Agreement."[25]

Third, the Settling Parties assert that the Settlement Agreement is in the public interest. Settling parties note that the Settlement Agreement arrives at an overall 2017 test year "consolidated gas and electric service rate and bill impact" of approximately one percent, which Settling Parties believe achieves a fair balance between safety, reliability and affordability. Finally, and importantly for this Commission, Settling Parties assert that the Settlement Agreement will enable PG&E to comply with its obligations under Pub. Util. Code § 451 to "furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities…as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

3.1. Framework for Preparing this Decision

In the sections which follow, we review the Settlement Agreement in the order in which it was presented. For each section, we provide Settling Parties' description of the issue, and address that issue. If we agree with the resolution, we state that the outcome is reasonable and should be adopted. In

[25] *Id.* at 10.

the event we disagree, or determine that additional discussion and clarification of a provision is needed, we provide that as necessary.

The ultimate monetary outcome of our decisions on each issue is represented in the "results of operations" table for PG&E, as shown Appendix A of this decision. The results of operations table sets forth all of the components of the revenue requirement, which consists of the total operating and maintenance (O&M) costs, and the capital-related costs, that we have determined are necessary to support PG&E's operations. To arrive at the overall revenue requirement, each of the pertinent line items on the results of operations table is discussed in the context of the testimony and the settlements regarding that item. The results of operations table reflects all of the costs or methodologies we have found to be reasonable as inputs into PG&E's Results of Operation (RO) model, which is used by PG&E to calculate the revenue requirement amount that is needed to allow the company, on a forecast basis, to earn the authorized rate of return on its investments.

Since the evidence and arguments in this proceeding are voluminous, and the Settlement Agreement reaches agreement on all but two of the many originally disputed issues, we focus our attention on the settled results, and do not try to summarize each party's positions on each individual issue. However, that does not mean that we have overlooked individual issues raised by the parties. We have reviewed all of the exhibits in this proceeding, as well as the workshop and hearing transcripts, and considered all of the arguments and issues that parties have raised in deciding what costs should be adopted. This review and evaluation process included the following:

- Review of all of the exhibits pertaining to each section of this decision. The exhibits reviewed include the direct and rebuttal testimony, the applicable workpapers, and the other exhibits prepared and entered into evidence in the course of this proceeding.

- Review and evaluation of the positions of the parties on the issues raised, especially as summarized in the JCE, and comparison and evaluation of each party's forecasted costs and methodologies with the outcomes reached in the Settlement Agreement.

- Consideration of the state of the economy and the economic outlook as described in the parties' exhibits, and comparison of the forecasts of the parties and the agreed-upon settlement amounts in light of the economic outlook.

- Review of the PPH transcripts and written correspondence from PG&E's ratepayers regarding PG&E's request.

The review and evaluation process described above results in our determination of the revenue requirements that are appropriate in order for PG&E to provide safe and reliable service at just and reasonable rates, as required by Pub. Util. Code § 451.

3.2. The Settling Parties

The Settling Parties explain that they represent a variety of interests other than those of PG&E. For example, ORA, TURN, CFC and NDC represent the diverse interests of consumers of gas and electricity, including low-income consumers. SBUA represents the interests of small businesses. A4NR represents the interests of consumers concerned about PG&E's nuclear operations. CforAT represents the interests of disabled customers. CUE represents the interests of represented utility employees at PG&E and other utility employees throughout the state. CAUSE represents the interests of consumers with a focus on utility safety. EDF represents the interests of consumers regarding environmental issues. MCE represents the interests of consumers regarding community choice aggregation and related issues. Merced ID, Modesto ID, and SSJID represent the interests of irrigation districts.[26]

3.3. Non-Settling Parties

This is not an all-party settlement, but Settling Parties describe it as "comprehensive" because all the parties that filed testimony in this proceeding are signatories. Parties that did not file testimony or join in the Settlement Agreement are listed below:

- Energy Producers & Users Coalition
- Southern California Gas Company
- Alliance for Retail Energy Market and Direct Access Customer Coalition
- SCE
- SDG&E
- Californians for Green Nuclear Power
- Friends of the Earth
- City & County of San Francisco
- County of San Luis Obispo
- City of Hayward
- City of San Luis Obispo
- Energy Freedom Coalition of America, LLC
- Sonoma Clean Power
- Transmission Agency of Northern California and State Water Contractors

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[26] *Id*. at 2-3.

- California Manufacturers & Technology Association

3.4. The Settling Parties' Litigation Positions

In the Settlement Motion, Settling Parties summarized their overall litigation positions in this proceeding. To ensure accuracy regarding parties' positions, we reproduce much of that summary below.

3.4.1. PG&E's Position

PG&E's litigation position would result in base revenue requirements of $4.279 billion for electric distribution, $1.801 billion for gas distribution, and $2.155 billion for electric generation, resulting in increases over currently authorized revenues of $67 million for electric distribution, $59 million for gas distribution, and $193 million for electric generation. In addition, adoption of PG&E's litigation position would result in post-test year increases of $467 million in 2018 and $368 million in 2019 ($263 million in 2018 and $175 million in 2019 for electric distribution, $145 million in 2018 and $150 million in 2019 for gas distribution, and $59 million in 2018 and $43 million in 2019 for electric generation).

PG&E also sought a variety of other non-revenue requirement-related relief, such as the proposed closure of 26 customer service offices. A complete list of PG&E's requested relief is set forth in PG&E's September 1, 2015 Application.

3.4.2. ORA's Position

As reflected in ORA's testimony, ORA's litigation position recommended a total 2017 revenue requirement of $4.067 billion for electric distribution, $1.683 billion for gas distribution, and $2.081 billion for electric generation, resulting in a decrease of $146 million, a decrease of $59 million, and an increase of $119 million, respectively, over currently authorized electric and gas distribution and generation-related revenues.

For 2018 and 2019, ORA recommended overall increases of $274 million and $283 million, respectively, or, using an alternative methodology, $444 million and $361 million.[27] ORA's primary recommendation would have resulted in increases of $142 million and $147 million for electric distribution in 2018 and 2019, respectively; $59 million and $61 million for gas distribution in 2018 and 2019, respectively; and $72 million and $75 million for electric generation in 2018 and 2019, respectively.

ORA also proposed a four-year GRC term (i.e., 2017-2020). For 2020, ORA recommended a 3.5 percent increase in revenues over 2019 levels. ORA opposed closing 26 customer service offices.

3.4.3. TURN's Position

TURN made a number of recommendations, addressing almost every aspect of PG&E's operations. These recommendations included: reducing overall Administrative and General and Human Resources (or HR) spending; reducing ratepayer funding of PG&E's Short Term Incentive Plan (STIP); reducing Customer Care costs; reducing electric and gas distribution capital and expense items and related ratemaking adjustments for deferred or imprudent gas distribution spending; reducing electric generation capital and expense items and related ratemaking adjustments; reducing depreciation and rate base for

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[27] Settling Parties state that PG&E derived these numbers using ORA's Results of the Operations model and applying the parameters ORA specified in testimony. Settling Parties cite Exhibit ORA-21 at 21-26.

numerous items; rejecting or reducing funding for numerous real estate projects and activities; and rejecting certain political costs. TURN also opposed PG&E's proposal to close up to 26 customer service offices, and offered policy recommendations related to safety, risk, and integrated planning; non-tariffed products and services; and Diablo Canyon, among other things.

3.4.4. A4NR's Position

A4NR recommended that PG&E file an annual Tier 1 advice letter describing plans to extend the operating licenses and authorities for the Diablo Canyon Nuclear Power Plant (Diablo Canyon). A4NR provided various ratemaking recommendations concerning the operations of Diablo Canyon, including a recommendation to provide alternative performance-based ratemaking.

3.4.5. CforAT's Position

As noted above, in lieu of providing independent testimony in this GRC, CforAT negotiated a Memorandum of Understanding with PG&E regarding various improvements to customer service for persons with disabilities. On September 1, 2015, CforAT and PG&E jointly submitted this MOU as part of Exhibit PG&E-6.

3.4.6. CUE's Position

CUE recommended increasing safety and reliability of both the gas and electric distribution systems by accelerating the rate of replacing aging infrastructure but reducing the revenue requirement by $68 million by lengthening the depreciation schedule for certain equipment. CUE opposed closing 26 customer service offices.

3.4.7. CAUSE's Position

CAUSE provided recommendations concerning the implementation of international standards and broader involvement of field employees in assessing safety conditions.

3.4.8. CFC's Position

CFC recommended various reductions concerning PG&E's insurance forecast and a reduction for the 2017 Gas Distribution Corrective Maintenance expense.

CFC supported PG&E's electric distribution reliability upgrade expenditures, proposed a requirement that PG&E continue to narrow the reliability performance gap between districts/divisions, and supported combining two existing electrical distribution reliability reports into one.

CFC recommended restructuring IT project budgets to better align with ratepayers' income growth and proposed an econometric forecast method for uncollectibles expense, rather than the established moving average revenue factor approach.

3.4.9. EDF's Position

EDF addressed PG&E's expenses and system improvements in relation to methane emissions reductions and long-term planning. EDF sought to ensure that PG&E has the ability to implement anticipated regulations requiring methane emissions reductions.

3.4.10. MCE's Position

MCE recommended revising the methodology used for allocating PG&E's Public Purpose Program overhead expenses to improve competitive neutrality and allocating the legal costs associated with developing PG&E's Power Purchase Agreements (PPAs) to its generation rate.

3.4.11. Merced and Modesto IDs' Position

Merced ID and Modesto ID recommended rejecting PG&E's forecast for customer retention activities and booking the costs below-the-line, conditioning Economic Development Rate revenue requested in Phase 1 on the firm showing required by D.13-10-019 in Phase 2, and requiring continuation of transparent cost information for distribution projects by planning area.[28]

3.4.12. NDC's Position

NDC recommended evaluation of executive compensation, an increase to PG&E's low-income consumer marketing, education and outreach budget, and gradually reducing the need for customer service offices.

3.4.13. SBUA's Position

As noted above, SBUA negotiated an MOU with PG&E that includes a variety of service improvements for small businesses. On September 1, 2015, SBUA and PG&E jointly submitted this MOU as part of Exhibit PG&E-6. SBUA advocated in the proceeding for the Commission to adopt the MOU and allocate sufficient funding for its provisions.

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[28] D.13-10-019 is the Commission's decision authorizing PG&E to offer Economic Development Rate tariff options.

3.4.14. SSJID's Position

SSJID recommended no funding for Customer Retention activities, disallowing ratepayer funding for the Economic Development Program, and denying a variety of forecasted items.

4. Summary and Review of the Settlement Agreement

In this section of the decision, we review each provision of the Settlement Agreement and make decisions regarding whether its terms are reasonable and should be approved.

Articles 1 and 2 of the Settlement Agreement provide a brief introduction to the Settlement Agreement and set forth its procedural history. Article 3 of the Settlement Agreement sets forth the settled issues, divided between two major sections: Financial Provisions that result in the overall settled revenue requirement (Section 3.1), followed by Non-Financial Provisions that determine a number of obligations for PG&E over the three-year GRC cycle (Section 3.2). Article 4 of the Settlement Agreement sets forth the two contested issues over which the Settling Parties were unable to reach consensus. Article 5 includes General Provisions of the Settlement Agreement.

After providing testimony containing an overview of PG&E's GRC request and testimony regarding PG&E's safety, risk and integrated planning that was required by the Commission in its decision on PG&E's 2014 GRC,[29] the core of PG&E's GRC testimony was organized such that PG&E provided a separate exhibit for each "Line of Business" (LOB) in the company.

[29] Exhibits PG&E-1 and PG&E-2, respectively.

First, PG&E's three "operational" lines of business:[30]

- Gas Distribution (Exhibit PG&E-3)
- Electric Distribution (Exhibit PG&E-4)
- Energy Supply (Exhibit PG&E-5)

Next, the lines of business that support the operational lines of businesses:

- Customer Care (Exhibit PG&E-6)
- Shared Services and IT (Exhibit PG&E-7)
- Human Resources (Exhibit PG&E-8)
- Administrative and General (including Corporate Services) (Exhibit PG&E-9)

PG&E's total GRC revenue requirement is the total of the direct costs authorized for the three operational LOBs, plus Customer Care costs that are assigned to the distribution LOBs either directly or using an allocation method, plus Human Resources, Administrative and General (A&G), and Shared Services/IT costs, which are assigned to each operational LOB using an allocation method.

For the LOBs addressed in Exhibits PG&E-3 through PG&E-7, PG&E discusses its GRC requests organized by groups of related activities called Major Work Categories (MWC), while Exhibits PG&E-8 and PG&E 9 are presented primarily in Federal Energy Regulatory Commission (FERC) account data, with the exceptions of technology projects and capital costs which are presented in

[30] The Federal Energy Regulatory Commission accounts for the operations of a combined gas and electric utility using three "functional areas": gas distribution, electric distribution and generation.

MWCs. PG&E notes that since its 2014 GRC, it has created new, or modified existing, MWCs to provide greater reporting granularity for its operations.[31]

Regarding the distinction between PG&E's use of FERC account data and its use of MWC, PG&E states that although the portion of its accounting system that is used to track costs by MWC does so without regard to which FERC account those costs will be booked, PG&E is required to report its financial results and set forth its request for funding using a FERC account format. For this reason, Exhibit PG&E-10 presents PG&E's accounting system/MWC forecasts in equivalent FERC account amounts and shows the specific FERC account to which the forecasts are assigned.

The financial results of the Settlement Agreement are presented in the FERC-required functional area format (see Agreement, Appendix A, page 1). In Exhibit PG&E-41, PG&E provides a more detailed breakdown of the settled amounts, showing both expense- and capital-related line items. The table below provides this information at the total GRC level. The entire expanded table, with functional area detail, is provided in Appendix A of this decision.

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[31] Within a Major Work Category, some LOBs create Maintenance Activity Type (MAT code) structures to allow for planning and tracking at the sub-program level.

Pacific Gas And Electric Company
2017 General Rate Case Results Of Operations
Settlement Agreement
Summary Of Proposed Increase Over Adopted 2016
Total General Rate Case
(Millions Of Nominal Dollars)

		2016	2017	2017	2017	2017	2017
		Adopted	PG&E Proposed	Difference (Proposed vs. Adopted)	Settlement	Difference (Settlement vs. Adopted)	Difference (Settlement vs. Proposed)
Line No.		(A)	(B)	(C=B-A)	(D)	(E=D-A)	(F=D-B)
	Description						
	Expense:						
1	Operation and Maintenance	1,664	1,825	161	1,794	131	(31)
2	Customer Services	319	361	42	334	15	(27)
3	Administrative & General	1,011	974	(36)	912	(99)	(62)
4	Less: Revenue Credits (Other Operating Revenues (OOR) & Wheeling)	(131)	(140)	(9)	(152)	(21)	(12)
5	FF&U, Other Adjs, Taxes Other than Income	38	184	146	170	132	(14)
6	Subtotal Expense	2,900	3,205	304	3,058	158	(146)
	Capital-Related:						
7	Depreciation, Decommissioning and Amortization	2,229	2,474	245	2,398	169	-76
8	Taxes: State and Federal Income, Property	1,066	1,082	16	1,070	4	-13
9	Federal Tax Repair Benefit Net of Flowback	-186	-504	-318	-483	-297	21
10	Return	1,906	1,978	72	1,961	55	-17
11	Subtotal Capital-Related	5,016	5,030	15	4,946	-70	-84
12	Total Retail Revenue Requirement	7,916	8,235	319	8,004	88	-230

4.1. Financial Provisions of the Settlement (Section 3.1)

Section 3.1 of the Settlement Agreement addresses financial provisions of the Settlement, and Section 3.1.1 presents the overall revenue requirement provisions for the 2017 Test Year and the 2018 and 2019 post-test years. Due to the process through which the Settlement Agreement appears to have been reached and thus presented in the Joint Motion and Agreement,[32] we first summarize the overall settled outcomes, and then review the individual revenue requirement items that produce those outcomes, and conclude with our overall decision on the Financial Provisions of the Settlement Agreement.

4.1.1. Overall Revenue Requirement (Section 3.1.1)

4.1.1.1. 2017 Test Year (Section 3.1.1.1)

Section 3.1.1.1 of the Settlement Agreement addresses the 2017 Test Year. As noted above, PG&E's original application sought a 2017 revenue requirement increase of $457 million over previously authorized rates. In PG&E's rebuttal testimony, PG&E reduced its request to an increase of $319 million. In its testimony, ORA recommended an $85 million decrease to PG&E's 2017 revenue requirement from previously authorized rates. CUE recommended an overall $68 million reduction to PG&E's recommended revenue requirement. TURN provided a broad number of specific recommended reductions to PG&E's forecast, but did not calculate an overall recommended revenue requirement. No other party provided an overall revenue requirement recommendation.

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[32] *See*, Settlement Workshop Reporter's Transcript (RT) at 19-26.

Section 3.1.1.1 of the Settlement Agreement provides for a 2017 revenue requirement increase of $88 million over PG&E's 2016 revenue requirement. The increases (decreases) are ($62) million for electric distribution, ($3) million for gas distribution, and $153 million for electric generation.

The table below summarizes the range of proposed 2017 increases, and where the Settlement Agreement falls within that range (in millions of dollars).

	PG&E application (September 1, 2015)	PG&E revised request (May 27, 2016)	**Settlement (August 3, 2016)**	CUE Testimony (April 29, 2016)	ORA Testimony (April 8, 2016)
2017 Test Year	$457	$319	**$88**	($68)	($85)

Settling Parties assert that these overall amounts represent a fair compromise of the Settling Parties' litigation positions. In the sections that follow, we discuss each underlying component of the agreed-upon amounts that comprise the $88 million increase over PG&E's 2016 revenue requirement.

4.1.1.2. 2018-2019 Post-Test Years (Section 3.1.1.2)

Section 3.1.1.2 of the Settlement Agreement addresses the 2018 and 2019 Post-Test Year revenue requirements. PG&E's original application sought 2018 and 2019 revenue requirement increases of $489 million and $390 million, respectively. In PG&E's update testimony, PG&E reduced its requested increases to $469 million and $368 million, respectively.

PG&E also proposed to continue the "Z-factor" mechanism adopted in PG&E's 2014 GRC to capture exogenous events that have a major impact on PG&E's cost of service, including a one-time $10 million deductible per event. A

Z-factor event is defined as a significant event that is beyond the utility's ability to control and causes large changes in its cost structure.[33]

In its testimony, PG&E argues that "Commission adoption of sufficient Post-Test Year attrition adjustments for 2018 and 2019 is necessary in order to provide PG&E with the funds it needs to provide safe and reliable service to customers, while offering PG&E a fair opportunity to earn the rate of return found reasonable by this Commission."[34] PG&E further explains that "a critical element of a fundamentally sound attrition mechanism is the recognition that expense escalation and growth in rate base are separate and distinct drivers for Post-Test Year cost growth and should be reflected in the attrition mechanism accordingly." Thus, PG&E requested in testimony that the Commission adopt a Post-Test Year mechanism that (1) escalates adopted test year expense amounts and (2) models capital revenue requirement growth based on adopted Test Year plant additions.[35]

PG&E reiterates that this separate treatment of expense growth and capital revenue requirement growth is necessary because the fundamental drivers for each are different, and asserts that its proposed attrition increases incorporate the two primary drivers of increases in a utility's cost of service: (1) the increase in labor and non-labor operating expenses caused by cost escalation, and (2) the increase in rate base and capital-related costs that result from capital

[33] Exhibit PG&E-11, Chapter 2 page 2-3.

[34] Exhibit PG&E-11 at page 1-1.

[35] *Ibid.*

expenditures to replace aging infrastructure, serve new customers, and manage growth in system load.[36]

The attrition mechanism proposed by PG&E in testimony would have allowed for pre-determined increases in the various components of PG&E's adopted cost-of-service revenue requirement based on a forecasting methodology appropriate for each component. For expenses, PG&E proposed that an appropriate escalation rate be applied to 2017 test year adopted amounts, using the best source available to project cost escalation in each expense category. For capital, PG&E proposed that capital revenue requirement growth in the attrition years be determined by the adopted 2017 test year plant additions plus escalation, forecasted depreciation, and the estimated change in deferred tax liabilities. This follows the approach adopted by the Commission in Southern California Edison's 2012 GRC (A.13-11-003). The 2018 and 2019 escalation of the adopted Test Year capital additions would be based on Global Insight Utility Capital Cost escalation factors as described in Exhibit PG&E-10 and would be "locked in" upon a final Commission decision in this proceeding. However, PG&E also proposed to limit the post-test year addition amounts for 2018 and 2019 to the amounts supported by PG&E's separately-prepared "bottom up" forecast, if that forecast was lower than the amount produced by PG&E's escalation method.[37]

In its testimony, ORA provided primary and alternative recommendations for the post-test years. ORA's primary recommendation was that PG&E receive

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[36] *Id.* at 1-9.

[37] *Id.* at 1-6 through 1-7.

a base revenue attrition increase of 3.5% per year. This figure is based on the average annual attrition increases adopted by the Commission in PG&E's 2007, 2011, and 2014 GRCs and in Sempra's 2008 and 2012 GRCs.[38] ORA's methodology would result in increases for 2018 and 2019 of $274 million and $283 million, respectively. ORA's alternative recommendation uses PG&E's escalation-based methodology, but with different escalators. This results in recommended increases for 2018 and 2019 of $444 million and $361 million, respectively.[39]

TURN also made primary and alternative recommendations for 2018 and 2019. TURN's primary recommendation was for increases of $469 million and $250 million, respectively. TURN's alternative recommendation was for increases of $458 million and $290 million, respectively.

No other party provided an overall revenue requirement recommendation for the post-test years.

The Settling Parties agreed to adopt the amounts from ORA's alternative recommendation: Section 3.1.1.2 of the Settlement Agreement provides that PG&E's annual post-test year adjustment for 2018 and 2019 will be fixed dollar amounts of $444 million in 2018, and $361 million in 2019. This provision also adopts ORA's recommendation to limit PG&E's exogenous Z-factor proposal to years other than the test year.

The table below summarizes the range of proposals, and places the Settlement Agreement within that range.

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[38] Exhibit ORA-21 at 17.

[39] *Id.* at 21-26.

	PG&E application	PG&E revised	TURN primary	TURN alternative	**Settlement Agreement**	ORA alternative	ORA primary
2018	$489	$469	$469	$458	**$444**	$444	$274
2019	$390	$368	$250	$290	**$361**	$361	$283

The Settling Parties assert that because the Settlement Agreement results in additional cost containment incentives for PG&E that are consistent with recommendations from ORA and TURN, the Settlement Agreement's treatment of post-test year ratemaking is reasonable, in the public interest, and should be adopted.

4.1.1.3. 2020 Post-Test Year (Section 3.1.1.3)

In its testimony, ORA proposed a third attrition year in 2020, so that this proceeding would result in a four-year (2017-2020) rate case cycle. In the Joint Motion, Settling Parties report that the parties were unable to gain consensus on whether the term of PG&E's next GRC should be three or four years.

TURN, A4NR, CAUSE and CFC recommend that the term of PG&E's next GRC be three years - the test year and two post-test years.

PG&E and ORA recommend that the term of PG&E's next GRC be four years - the test year and three post-test years.

We resolve this contested issue later in this decision.

4.1.1.4. Exogenous Changes (Section 3.1.1.4)

In past attrition mechanisms, we have included a provision identified as a Z-factor, to cover certain unforeseen exogenous events that may occur between test years. The Z-factor is a mechanism designed to prevent both windfall profits and large financial losses as a result of changes in costs outside of utility control. Section 3.1.1.4 of the Settlement Agreement adopts ORA's recommendation to limit PG&E's exogenous Z-factor proposal to years other than the test year. Thus, for the post-test years, the Settling Parties agree that PG&E's mechanism will allow for positive and negative revenue requirement adjustments for exogenous Z-factors, as identified in D.05-03-023 and affirmed in PG&E's 2014 GRC decision,[40] with a $10 million deductible amount applicable to each factor each year.

The criteria for a Z-factor's occurrence, as identified in D.05-03-023 are the following:

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 a normal part of doing business;
5. The costs must have a disproportionate impact on the utility;
6. The costs and event are not reflected in the rate update mechanism;
7. The costs must have a major impact on overall costs;
8. The cost impact must be measurable; and
9. The utility must incur the cost reasonably.

Having established the foundation for the overall revenue 2017-2020 revenue requirements as agreed upon by the Settling Parties, we now turn to our review of the Settlement Agreement's outcomes for each of PG&E's lines of business in 2017. These sections of the Settlement Agreement provide MWC-specific itemization of the overall reductions summarized above. We

[40] D.05-02-023 at 29-31, D.14-08-032 at 661.

conduct our review at that level of detail to ensure that the individual agreements that add up to the totals are each reasonable outcomes as well.

4.1.2. Gas Distribution (Section 3.1.2)

Section 3.1.2 of the Settlement Agreement addresses revenue requirement issues regarding PG&E's Gas Distribution LOB.

The Settlement Agreement reduces PG&E's Gas Distribution forecast expense request of $528 million to $510 million, an $18 million reduction. In testimony, ORA proposed a reduction of $70 million, while TURN proposed a reduction of $5 million.[41]

The Settlement Agreement reduces PG&E's Gas Distribution forecast capital request of $1.011 billion to $1.001 billion, a $10 million reduction. In testimony, ORA proposed no reduction, while TURN proposed a reduction of $406 million.[42]

The agreed-upon reductions are summarized below.

4.1.2.1.1. Expense Reductions

- $5.2 million for corrosion control (MWC DG and FH);
- $2.5 million for leak management (MWC FI);
- $0.5 million for other support activities (MWC AB); and
- $9.3 million for gas operations technology (MWCs GZ and JV).

4.1.2.1.2. Capital Reductions

- $10 million for new business (MWC 29)

[41] Settlement Agreement, Appendix A, at 2.

[42] *Ibid.*

The Settling Parties assert that the Settlement for Gas Distribution reflects a reasonable compromise of the positions taken by the parties, as reflected in Chapter 2.A of the JCE (Exhibit PG&E-37).

As explained above, certain revenue requirements from other settled amounts in other PG&E Lines of Business are also allocated to the Gas Distribution LOB. Once those allocations are incorporated into the revenue requirement, the Gas Distribution settled outcome reflects a net reduction of $3 million from PG&E's 2016 revenue requirement, which is also $62 million less than PG&E requested in its update testimony. The table below provides this level of detail.

Pacific Gas And Electric Company
2017 General Rate Case Results Of Operations
Settlement Agreement
Summary Of Proposed Increase Over Adopted 2016
Gas Distribution
(Millions Of Nominal Dollars)

		2016	2017	2017	2017	2017	2017
		Adopted	PG&E Proposed	Difference (Proposed vs. Adopted)	Settlement	Difference (Settlement vs. Adopted)	Difference (Settlement vs. Proposed)
Line No.		(A)	(B)	(C=B-A)	(D)	(E=D-A)	(F=D-B)
	Description						
	Expense:						
1	Operation and Maintenance	375	449	74	433	58	(16)
2	Customer Services	138	144	6	139	1	(5)
3	Administrative & General	260	276	16	259	(2)	(18)
4	Less: Revenue Credits (Other Operating Revenues (OOR) & Wheeling)	(25)	(18)	8	(28)	(3)	(10)
5	FF&U, Other Adjs, Taxes Other than Income	48	55	6	50	2	(4)
6	Subtotal Expense	797	906	110	853	56	(54)
	Capital-Related:						
7	Depreciation, Decommissioning and Amortization	442	484	42	480	38	(4)
8	Taxes: State and Federal Income, Property	195	211	16	208	13	(3)
9	Federal Tax Repair Benefit Net of Flowback	(47)	(223)	(176)	(219)	(172)	4
10	Return	355	422	67	417	62	(6)
11	Subtotal Capital-Related	945	894	(51)	886	(59)	(8)
12	Total Gas Distribution Revenue Requirement	1,742	1,800	59	1,739	(3)	(62)

4.1.2.2. Discussion of Gas Distribution Revenue Requirement Items

Based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement, we find that the agreed-upon 2017 Gas Distribution expenses and capital expenditures are reasonable and we conclude that they should be adopted.

4.1.3. Electric Distribution (Section 3.1.3)

Section 3.1.3 of the Settlement Agreement addresses revenue requirement issues regarding PG&E's Electric Distribution LOB.

The Settlement Agreement reduces PG&E's Electric Distribution forecast expense request of $722 million to $715 million, a $7 million reduction. In testimony, ORA proposed a reduction of $48 million, while TURN proposed a reduction of $23 million.[43]

The Settlement Agreement reduces PG&E's Electric Distribution forecast capital request of $1.796 billion to $1.694 billion, a $101 million reduction. In testimony, ORA proposed a reduction of $88 million, while TURN proposed a reduction of $171 million.[44]

The agreed-upon reductions are summarized below.

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[43] *Ibid.*

[44] *Ibid.*

4.1.3.1.1. Expense Reductions

- $2.0 million for overhead maintenance (MWC KA);
- $1.2 million for capacity, including the Voltage and Volt-Ampere Reactive Optimization (VVO) program (MWCs BA and JV);
- $1.4 million for technology (MWC JV); and
- $2.5 million for mapping and records management (MWC GE).

4.1.3.1.2. Capital Reductions

- $7 million for reliability (MWC 49);
- $10 million for substation asset management (MWC 48);
- $40.5 million for capacity projects, including those in support of the VVO and Distributed Energy Resource Integration programs (MWCs 06, 46 and 2F);
- $43.4 million for new business (MWC 16); and
- $23.7 million for Rule 20A undergrounding work (MWC 30).

The above reductions are offset by increases in the following areas:

- $14 million for cable replacement (MWC 56);
- $0.4 million for grasshopper switches (MWC 08); and
- $8.5 million for Fault Location, Isolation and Service Restoration System (FLISR) (MWC 49).

The Settling Parties assert that the Settlement for Electric Distribution reflects a reasonable compromise of the positions taken by the parties, as reflected in Chapter 2.B of the JCE (Exhibit PG&E-37).

As explained above, certain revenue requirements from other settled amounts in other PG&E lines of business are also allocated to the Electric Distribution LOB. Once those allocations are incorporated, the Electric Distribution settled outcome reflects a net reduction of $62 million from PG&E's

2016 revenue requirement, which is also $128 million less than PG&E requested in its update testimony. The table below provides this level of detail.

Pacific Gas And Electric Company
2017 General Rate Case Results Of Operations
Settlement Agreement
Summary Of Proposed Increase Over Adopted 2016
Electric Distribution
(Millions Of Nominal Dollars)

		2016	2017	2017	2017	2017	2017
		Adopted	PG&E Proposed	Difference (Proposed vs. Adopted)	Settlement	Difference (Settlement vs. Adopted)	Difference (Settlement vs. Proposed)
Line No.		(A)	(B)	(C=B-A)	(D)	(E=D-A)	(F=D-B)
	Description						
	Expense:						
1	Operation and Maintenance	649	721	72	711	62	(10)
2	Customer Services	181	212	31	193	12	(19)
3	Administrative & General	472	407	(65)	382	(90)	(25)
4	Less: Revenue Credits (Other Operating Revenues (OOR) & Wheeling)	(88)	(118)	(30)	(118)	(30)	0
5	FF&U, Other Adjs, Taxes Other than Income	78	90	12	82	4	(8)
6	Subtotal Expense	1,292	1,313	20	1,250	(43)	(63)
	Capital-Related:						
7	Depreciation,	1,279	1,435	156	1,364	86	(70)
8	Taxes: State and Federal	641	658	18	651	11	(7)
9	Federal Tax Repair Benefit	(103)	(246)	(143)	(230)	(127)	17
10	Return	1,104	1,120	16	1,115	11	(5)
11	Subtotal Capital-Related	2,920	2,966	46	2,901	(19)	(65)
12	Total Electric Distribution Revenue Requirement	4,212	4,279	66	4,151	(62)	(128)

4.1.3.2. Additional Electric Distribution Financial Issues

In addition to the major expense and capital items summarized above, the Settlement Agreement includes other settled items that have a financial impact on the final Electric Distribution revenue requirement. Settling Parties assert that settlement of the issues set forth below reflects a reasonable compromise of the positions taken by the parties, many of which are reflected in Chapter 2 of the JCE. Settling Parties state that, given the various parties' recommendations in this area, these provisions are supported by the record and, in light of the various compromises set forth in this Agreement, these provisions are reasonable and in the public interest.

4.1.3.3. Pole Replacement in 2018 and 2019 (Section 3.1.3.2)

In response to PG&E's forecast for pole replacement, CUE recommended that PG&E should replace 9,400 more poles per year than PG&E forecast, at a capital cost of $130.09 million per year.

Section 3.1.3.2 of the Settlement Agreement provides that PG&E will spend an additional $4 million for 2018 and an additional $6 million for 2019 for the accelerated retirement of higher risk poles, absorbing the cost of the increased pole replacement activity in the settled 2018 and 2019 post-test year revenue requirements.

4.1.3.4. Cable Replacement (Section 3.1.3.3)

In response to PG&E's forecast for cable replacement, CUE recommended that PG&E increase its replacement of high molecular weight polyethylene (HMWPE) cable from 11.3 – 13 miles to 43.25 miles.

Section 3.1.3.3 of the Settlement Agreement provides that PG&E shall plan to double its proposed level of HMWPE cable replacement work from 13 miles to 26 miles in 2017, as well as an additional 13 miles per year for the post-test years (i.e., a total of 21 miles in 2018 and 26 miles in 2019). The Section also provides that prior to any cable replacement project, PG&E shall evaluate whether targeted cable replacement using testing or, in select cases, rejuvenation is a more cost-effective option for such cable.

4.1.3.5. Grasshopper Switches (Section 3.1.3.4)

Section 3.1.3.4 of the Settlement Agreement adopts CUE's recommendation that PG&E increase its replacement rates for "grasshopper switches" from 20 per year to 30 per year. CUE explains in its testimony that grasshopper switches are an antiquated type of overhead switch still found on the PG&E distribution system. CUE quotes PG&E's statement that grasshopper switches "do not meet new operating criteria" and can "negatively affect the operational flexibility of the grid."[45] PG&E has established a program dedicated to grasshopper switch replacement. As of the end of 2014 there were 185 grasshopper switches left on PG&E's system.[46]

No other party submitted testimony on this issue.

4.1.3.6. Fault Location, Isolation and Service Restoration (Section 3.1.3.5)

PG&E explains that Fault Location, Isolation and Service Restoration (FLISR) systems are self-restoring feeder automation technology designed to

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45 Exhibit CUE-1 at 35, citing Exhibit PG&E-4 workpapers page WP 9-10.

46 *Id.* at 36, citing PG&E's response to Data Request CUE 1-20a.

improve service reliability. CUE describes FLISR as a known technology that PG&E has been implementing for years and asserts that FLISR installations are "one of the most cost-effective means to improve reliability that exist" and quotes PG&E's statement that "the FLISR automation system reduces the effect of outages to customers by quickly opening and closing automated switches. This reduces what may have been a sustained outage lasting one-to-two hours to less than five minutes for most of the affected customers."[47]

In response to PG&E's forecast for FLISR, CUE recommended that PG&E quadruple its FLISR installations from 77 to 308 per year in order to increase reliability at a high benefit to cost ratio.

Section 3.1.3.5 of the Settlement Agreement provides that PG&E shall increase its forecasted level of FLISR installations during the term of this GRC, from 77 to not more than 116 per year. The number and placement of FLISR installations shall be described and supported in PG&E's next GRC application.

4.1.3.7. Discussion of Electric Distribution Revenue Requirement Items

Based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement, we find that the agreed-upon 2017 Electric Distribution expenses and capital expenditures are reasonable and we conclude that they should be adopted.

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[47] *Id.* at 20, citing Exhibit PG&E-4 at 9-21.

With respect to PG&E's Rule 20A program, the Settlement Agreement includes a proposed capital reduction of $23.7 million for 2017 Rule 20A undergrounding work. In its original testimony, PG&E's proposed 2017 forecast for this item was $83.74 million. ORA proposed a forecast amount of $49.24 million, a reduction of $34.5 million.[48] The settled, agreed-upon 2017 forecast is $60 million. We find record support for the agreed-upon funding level in the Settlement Agreement as it is within the bookends of PG&E's and ORA's original testimony and is reasonable. But we remain concerned with PG&E's Rule 20A program and PG&E's management of the program, as explained below.

PG&E's Electric Rule No. 20 Tariff (Replacement of Overhead with Underground Electric Facilities) allows a city or county to convert existing overhead lines to underground at ratepayer expense, after determining that such action is in the general public interest.[49] As we stated above, one of the more noteworthy aspects of the PPHs conducted in this proceeding was the consistent presence of local government officials at every location, all of whom expressed strong opposition to ORA's proposals. Many officials also noted their concern regarding the Commission's treatment of the Rule 20A issue in PG&E's 2011 and

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[48] ORA also proposed to set PG&E's annual Rule 20A work credit allocation to zero for the 2017-2019 GRC period, to be reviewed for reintroduction in PG&E's 2020 GRC.

[49] "General public interest" determinations are based on the following reasons, listed in PG&E's Electric Rule No. 20: 1) Such undergrounding will avoid or eliminate an unusually heavy concentration of overhead electric facilities; 2) The street or road or right-of-way is extensively used by the general public and carries a heavy volume of pedestrian or vehicular traffic; 3) The street or road or right-of-way adjoins or passes through a civic area or public recreation area or an area of unusual scenic interest to the general public; and 4) The street or road or right-of-way is considered an arterial street or major collector. Cal. P.U.C. Sheet No. 30474-E.

2014 GRCs. In response to the concerns expressed by these officials, approximately half of the September 1, 2016 evidentiary hearing time devoted to examination of the Settlement Agreement was devoted to the Rule 20A issue. At the hearing, the City of Hayward was granted party status, and its representatives provided a statement for the record, responded to questions from the ALJ, and posed questions of their own to the PG&E witness who sponsored testimony about the Rule 20A program.[50]

Based on the record in this proceeding, as presented below, we are concerned that PG&E has in past years managed its Rule 20A program in a manner that is inconsistent with the Commission's intent. We therefore adopt two remedies intended to address our concerns, including an audit of the program. We begin with an overview of the program and a number of metrics that illustrate PG&E's operation of the program.

The Commission's current policy on undergrounding of electric and communications services and facilities dates back to 1967. In D.73078, "Interim Order Establishing New Rules for Electric and Communication Service Connections and Conversion of Overhead to Underground Facilities" the Commission noted that the underlying investigation (Case No. 8209) had been instituted in 1965 "to determine what revision of existing rules, what new rules, or new rates would be required to stimulate, encourage, and promote the undergrounding, for aesthetic as well as economic reasons, of electric and communications services and facilities." According to the Commission,

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[50] RT at 1036-1095.

"however useful and often necessary had been the seemingly total preoccupation with the engineering and commercial aspects of our utilities, the time had long passed when we could continue to ignore the need for more emphasis on aesthetic values in those new areas where natural beauty has remained relatively unspoiled or in established areas which have been victimized by man's handiwork."[51] The Commission found that "the citizens of California through their elected officials and representatives have indicated a demand for underground electric and communications facilities" and stated that "it is the policy of this Commission to encourage undergrounding."[52]

The most recent and significant developments in the Commission's policies and rules regarding undergrounding occurred beginning in 1999, when the Legislature passed AB 1149. That bill required the Commission to study ways to amend, revise, and improve the rules for the conversion of existing overhead electric and communications lines to underground service and to submit a report to the Legislature. In response, the Commission issued Order Instituting Rulemaking 00-01-005, *"Order Instituting Rulemaking Into Implementation of Assembly Bill 1149, Regarding Underground Electric and Communications Facilities."* After conducting a number of public workshops and public participation hearings, the Commission issued D.01-12-009, its "Interim Opinion Revising the Rules for Converting Overhead Lines to Underground." The Commission noted that "with very few exceptions, the public favors undergrounding for safety, reliability, aesthetic benefits, and property value

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[51] 67 CPUC 490.

[52] *Id.* at 512.

increases. The value of the workshops and the PPHs was to affirm the reasonableness of the current undergrounding program, and to identify some non-controversial measures that would immediately improve the current program administration of undergrounding." These measures included expanding electric Rule 20A criteria such that public interest projects could include arterial streets and major collectors, and allowing cities to "mortgage" Rule 20A allocations for up to five years (instead of the then-current three years) in response to cities' arguments that this would increase the number of large projects that they could pursue. The Commission also adopted measures intended to improve communication between the utilities and the affected communities regarding the status of undergrounding projects.[53]

There are two components that make up the Rule 20A undergrounding program, and both are typically established in the electric utilities' GRC proceedings. The Commission sets annual budgets for the spending, and establishes parameters that determine which communities will be able to make use of that funding in any given year.

In order to determine communities will receive funding in a given year, the Commission established a "work credit" allocation system, which operates in a manner akin to an airline frequent flyer program: the Commission sets an annual total amount of credits for distribution, and this total is allocated to

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[53] In D.01-12-009 the Commission also identified and deferred certain issues to a future Phase 2 of the proceeding, including whether adjustments to the Rule 20A allocation formula were appropriate. However, the Commission closed the Rulemaking proceeding in 2005, stating that "overtaking events in the electric industry required the Commission to manage and control its resources such that Phase 2 of the proceeding was never fully initiated beyond a Prehearing Conference."

individual communities according to specific allocation rules. Once a locality has accumulated a level of credits equal to their actual budget for an undergrounding project, they can turn them in and the project can get underway. As PG&E explains in its testimony,[54] every year, work credits are allocated to each community served by PG&E's electric distribution system according to an established formula:

> Pursuant to Section 2.b of PG&E's Rule 20 tariff, the amount allocated to a city or county will typically consist of the amount actually allocated to that community in 1990 as the base,[55] plus a share of any change [in allocations] from the 1990 level to the current year allocation total.

The second component of PG&E's operation of its Rule 20A program is its annual construction budget itself, i.e., the amount that PG&E seeks authority to collect in rates via this GRC and spend each year on projects. Determining how much to request is a forecasting exercise that PG&E explains in its testimony:[56]

> The 2016 through 2019 forecast was developed based upon Identified Project Work (including projects in which the requesting community is awaiting a revised General Conditions Agreement) and Forecast Other Work. The Identified Project Work forecast decreases in the years 2017, 2018, and 2019, and the Forecast Other Work increases. The further out in time, the less PG&E can identify specific projects associated with the program.

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54 Exhibit PG&E-4 at pages 18-6 to 18-7.

55 PG&E's 1990 base year work credit allocation was approximately $46.9 million.

56 Exhibit PG&E-4 at pages 18-5 to 18-6.

In this GRC, PG&E's forecasting process resulted in a capital spending request for $83.74 million in 2017, $83.068 million in 2018, and $72.064 million in 2019.[57]

With the work credit allocation method in place, and the annual budget determined, each interested community must still qualify pursuant to Commission-approved rules in order to receive funding for a specific project. PG&E explains that in order for a project to qualify for the Rule 20A Program, the project must meet specific criteria outlined in the Rule 20A tariff. Representatives from the governmental agency seeking to pursue a Rule 20A undergrounding project meet with PG&E's Rule 20A Liaison to determine the project qualification, and ensure there are sufficient work credits to complete the potential project. Thereafter, the governmental agency must pass an ordinance to create an underground district, addressing items such as identifying underground district boundaries, determining if the Rule 20A allocations will be used to make customer service panels compatible with the underground conductor, stating if the project is tied to road widening improvements and specifying how the project qualifies for Rule 20A funding under the tariff.[58]

The issue before us today is the relationship between the annual work credit allocations and PG&E's annual spending on Rule 20A projects, both the authorized budgets and the subsequently recorded levels. We demonstrate that relationship with the aid of testimony served in this proceeding by ORA.

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[57] *Id.* at 18-9, Table 18-1.

[58] *Id.* at 18-3.

First, ORA provides data showing the history of PG&E's annual work credit allocation levels:[59]

Annual Rule 20A
Work Credit Allocation

Year	Annual Work Credit Allocation (millions)
1989	$43.5
1990	$48.2
1991	$50.5
1992	$52.6
1993	$55.2
1994	$57.3
1995	$54.4
1996	$56.3
1997	$57.9
1998	$59.6
1999	$61.3
2000	$63.2
2001	$65.9
2002	$68.2
2003	$70.4
2004	$74.1
2005	$77.6
2006	$81.0
2007	$81.0
2008	$81.0
2009	$81.0
2010	$81.0
2011	$41.3
2012	$41.3
2013	$41.3
2014	$41.3
2015	$41.3

[59] Exhibit ORA-10, Figure 10-1 and supporting workpapers. ORA cites PG&E's response to ORA data request DR-ORA-104-Q10, Revision 1, Attachment 1.

The table shows that after growing steadily since 1989 and leveling off from 2006-2010, in 2011 the work credit allocation was reduced to approximately 50% of the 2010 level, and has remained at that lower level since that time. PG&E explains that the annual growth in allocation levels was the result of a Commission-approved escalation factor that PG&E stopped using after 2006,[60] which resulted in constant annual allocations until the significant reduction in 2011. That initial reduction was approved by the Commission as part of a settlement in PG&E's 2011 GRC. Rather than using the two part formula described in the Rule 20 tariff, the Commission approved a PG&E request and ordered PG&E to allocate work credits at the same level and in the same amount as its 2010 annual budgeted Rule 20A project amount, "in order to stop the escalation of work credit allocations."[61] In PG&E's 2014 GRC, the Commission stated that the Rule 20A work credit allocation amount of $41.3 million that was adopted in the 2011 GRC decision would continue through 2016. In doing so, the Commission noted that "for many years, the amount of work credits allocated was higher than the amount of Rule 20A work performed" by PG&E, and that "PG&E has repeatedly presented forecasts in prior GRCs with the intention of reducing the backlog in Rule 20A projects, but has also repeatedly spent less than the forecast."[62]

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[60] Exhibit PG&E-4 at page 18-7: "As stated in the 2011 GRC Testimony, PG&E continued to include an escalation factor in the allocation formula many years after it expired."

[61] D.11-05-018, Ordering Paragraph 6.

[62] D.14-08-032, Finding of Fact 120.

ORA's analysis of actual spending data obtained from PG&E in this proceeding bears out the Commission's concerns. The table below adds PG&E's Commission-approved annual budgets for that spending, and PG&E's actual annual spending, to the table above, and calculates the difference between the two amounts.[63] It is these results that greatly concern us.

Calculation of Annual Unspent Rule 20A Budgeted Funds (millions)

Year	Work Credit Allocation	PG&E Budget	Recorded Expenditures	Unspent Funds (unspent funds are shown as negative amounts)	Recorded as share of budget
	(A)	(B)	(C)	= (C)-(B)	
2000	$63.2	$41.0	$41.5	$0.5	101%
2001	$65.9	$45.0	$29.3	($15.7)	65%
2002	$68.2	$50.0	$37.8	($12.2)	76%
2003	$70.4	$55.2	$56.1	$0.9	102%
2004	$74.1	$53.1	$49.3	($3.8)	93%
2005	$77.6	$40.2	$42.0	$1.8	104%
2006	$81.0	$54.7	$68.4	$13.6	125%
2007	$81.0	$59.7	$45.4	($14.3)	76%
2008	$81.0	$53.4	$39.9	($13.5)	75%
2009	$81.0	$44.6	$41.1	($3.5)	92%
2010	$81.0	$41.4	$36.6	($4.8)	88%
2011	$41.3	$48.2	$33.6	($14.6)	70%
2012	$41.3	$61.8	$52.4	($9.4)	85%
2013	$41.3	$86.0	$69.4	($16.6)	81%
2014	$41.3	$69.9	$41.1	($28.9)	59%
2015	$41.3	$76.0	$42.9	($33.1)	56%

[63] Exhibit ORA-10, Figure 10-1 and supporting workpapers. ORA cites PG&E's response to ORA data request DR-ORA-104-Q10, Revision 1, Attachment 1 provided in Exhibit ORA-10-Atch 1, at 34. Complete data was provided only for 2000 onward.

Of the 16 years shown in the table above, PG&E's spending exceeded its Commission-authorized budget in one year and matched it in three years. In the other 12 years, PG&E reported spending as a share of its Commission-authorized budget by a range of 93% to a low--just last year--of only 56% of its authorized budget. Just since 2000, the accumulated amount of unspent budgeted funds is approximately $153 million.

One of the panelists at the August 30, 2016 workshop to review the Settlement Agreement was PG&E's Vice President of Electric Asset Management. When asked about the discrepancies between Commission- authorized Rule 20A amounts and PG&E's actual spending, he responded as follows:[64]

> ALJ: One thing I'm curious about is when PG&E receives a budget and doesn't spend the entire budget, where does that difference go?
>
> PG&E Witness: So when you say a "budget," you mean, like, an amount authorized in a GRC or --
>
> ALJ: Yeah. That's collected in rates; right?
>
> PG&E Witness: Right.
>
> ALJ: Then what happens?
>
> PG&E witness: It tends to be -- you know, one of the challenges with respect to these Rule 20A projects in particular is that they're very complex. They require a lot of coordination because it's often not just PG&E that has facilities in these areas. There may be cable TV and telecommunications, and it's a very complex coordination process.
>
> The projects do tend to take a long time, and so the pace at which the projects progress is sometimes different than what we had forecast. I think that's part of the – part of the issue.
>
> The -- the dollars get -- you know, again, there are things that increase and decrease over the course of -- of a GRC period. And I guess Ms. Sharp

[64] RT at 175-177.

> mentioned we've -- you know, we have spent more than --you know, than what was authorized over the period of time. So there were other emerging issues that were traded off that maybe had a more safety, reliability-oriented requirement than a Rule 20A project. But it is an area that we are constantly looking at because communities are counting on us to do the work. And we do consider it in our – our risk-informed budget allocation process as a commitment that's been made, so we do look to fund those projects as a high priority, you know, as part of that evaluation process.
>
> ALJ: Now, you can defer this next question to your witness for the hearings, but do you -- in your opinion, is PG&E authorized to defer those monies to non-Rule-20A uses?
>
> PG&E Witness: It gets to the -- I'm just looking at Mr. Frank because it gets to the question of how -- you know, PG&E's management discretion during a GRC period.
>
> ALJ: Right.
>
> PG&E Witness: So it falls into that category. We have an obligation to make sure we're meeting our commitments, and we also have an obligation to make sure we're addressing emergent, pressing safety and reliability issues. So we believe that – in a short answer, we do believe it is within that discretion.
>
> ALJ: Okay. Thank you.

We disagree with PG&E that its management has the discretion during a GRC period to defer Rule 20A funds to non-Rule 20A uses. Elsewhere in this decision we discuss issues surrounding PG&E's more general practice of "deferral of authorized work"; that is a common practice, and allowable when justified under certain circumstances, but our specific concern here is the systematic underspending shown in the table above, which is not a pattern that we would expect to see for this program area, where community demand is high.[65] Even more concerning to us is that we have no record in this proceeding regarding the actual use of the unspent Rule 20A funds, because the annual GRC "Budget Reports" submitted by PG&E at the Commission's direction do not provide that information.[66] We understand the testimony of PG&E witnesses that specific Rule 20A projects may be delayed for any number of reasons and that the implementation and completion of a full undergrounding project can be lengthy and complex. However, the data summarized above shows a consistent pattern of underspending with a growing deficit, rather than a situation where projects delayed in one year would at some point "catch up" such that all budgeted funds are spent for those projects, and PG&E's entire annual Rule 20A budget is spent on Rule 20A projects.

Our record in this proceeding provides no indication of where these funds have gone. Following hearings, PG&E prepared and served Exhibit PG&E-42, "Late Filed Exhibit on Rule 20A Project Spending Detail." In that Exhibit, PG&E represents that it has provided an overview of program spending in 2013-2016 compared to adopted funding levels, but most of that information is not, in fact, provided in the Exhibit, or conflicts with other record evidence. For example, PG&E states "in 2013, PG&E spent $69.4 million in the Rule 20A Program, consistent with the California Public Utilities Commission (CPUC) adopted

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[65] PG&E states in testimony that by the start of 2015, cities and counties in PG&E's service territory had approximately $519.9 million in total available work credits. Exhibit PG&E-4 at 18-7.

[66] Pursuant to D.14-08-032, PG&E provides annual reports in that GRC docket that account for its spending by MWC, comparing authorized amounts to budgeted and spent amounts, and explaining significant differences.

amount for the Rule 20A Program."[67] This statement conflicts with ORA's testimony, which summarizes data provided by PG&E and indicates that the Commission-adopted amount for the Rule 20A program in 2013 was $86 million.[68] Exhibit PG&E-42 also provides no comparisons at all for 2014-2016, stating only in the aggregate that "over the 2014-2016 period, PG&E expects to spend approximately $125 million, as compared to the Commission adopted amount of $145.8 million."[69] Finally, Attachment A of Exhibit PG&E-42 provides details on Rule 20A program budgeted and recorded spending during 2013, 2014 and 2015, but only at the project level with no comparison or analysis with respect to total funds budgeted and recorded spending. Nothing in Exhibit PG&E-42 gives this Commission comfort that all is well with PG&E's Rule 20A program.[70]

For the reasons discussed above, we conclude that an audit is necessary in order to ensure that PG&E has fully accounted for annual Rule 20A budgeted amounts, and to ensure that localities will receive the full benefit of these funds. The audit should also assess PG&E's progress in implementing the steps it has taken to increase its capability to perform Rule 20A conversions[71] as well as

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[67] Exhibit PG&E-42 at 1.

[68] *See* Table above, "Calculation of Annual Unspent Rule 20A Budgeted Funds" and PG&E's response to ORA Data Request DR-ORA-104-Q10, Revision 1, Attachment 1, provided in Exhibit ORA-10-Atch 1, at 34.

[69] Exhibit PG&E-42 at 1.

[70] The Commission does note, as did the assigned ALJ at hearings, that recent changes to the program's management appear promising for improved operations in the future.

[71] Exhibit PG&E 23 at 18-5.

PG&E processes to verify the eligibility of Rule 20A projects and the reliability of Rule 20A project cost estimates. The Commission's Energy Division shall oversee the audit. PG&E, the City of Hayward, and Commission staff are directed to meet and confer to jointly determine the scope of the audit and an estimate of the funding required for such an audit, which PG&E shall pay for using part of its authorized 2017 Rule 20A budget. Other governmental entities that are parties to this proceeding shall be also invited to the meet and confer session. PG&E and the City of Hayward shall jointly file and serve their jointly determined scope and funding estimate for the audit within 60 days of the effective date of this decision. The assigned Commissioner and assigned ALJ shall determine further procedural steps following receipt and review of the audit scope and funding estimate.

Furthermore, we conclude that the approach to setting work credit allocations and budgets that we have followed in the last two GRC cycles has not been successful. As we just discussed, even though we approved significant annual budgets (i.e., ratepayer funds) with the intention and expectation that PG&E would spend all of those funds in order to reduce the credit backlog, PG&E appears to have diverted a significant share of those funds to other uses. We reduced the allocations, but in turn PG&E simply reduced its spending, so any reduction in the backlog was muted. In fact, in just the five years since we reduced the work credit allocation in 2011, the amount of PG&E's budgeted-but-unspent Rule 20A funds has <u>grown</u> by $102 million. This was not our intention, and this outcome is inconsistent with the Commission's long-stated intentions for the Rule 20A program.

Since reasons specific to the Rule 20A program may prevent full expenditure of these funds, we will require PG&E to track the unspent amounts in a one-way balancing account so that they are spent on Rule 20A projects in the current and future years. We conclude that it is appropriate to direct PG&E to establish a Rule 20A balancing account that tracks the annual capital and expense costs for Rule 20A undergrounding projects, on a forecast and recorded basis. Overcollected balances in the account shall remain available for future Rule 20A projects.[72] The Commission shall review the balances in the account in PG&E's next GRC proceeding.

The September 1, 2015 Scoping Memo in this proceeding determined that one of the issues to be considered was whether the annual PG&E Electric Tariff Rule 20A work credit allocation amount of $41.3 million should be extended through 2019. This issue was addressed in the Settlement Agreement. In addition to their proposal regarding the budget for Rule 20A projects, Settling Parties also agreed to adopt PG&E's proposal that the Commission extend the annual Rule 20A work credit allocation amount of $41.3 million through the term of the 2017 GRC (Section 3.2.2.8 of the Settlement Agreement).

We continue to be concerned with PG&E's growing balance of allocated, but not yet redeemed, work credits. The accumulation for PG&E is nearly $1 billion, including committed projects and assuming maximum borrowing actually occurs over the next five years.[73] In order to reduce PG&E's

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[72] The settlement approved by the Commission regarding PG&E's 2011 test year GRC proceeding included an agreement that the Commission should deny PG&E's request in that proceeding for a Rule 20A balancing account. D.11-05-018 at 21 and Ordering Paragraph 30.

[73] Exhibit PG&E-4, Workpapers Supporting Chapters 13-19, WP Table 18-8, line 6 and PG&E response to ORA_207_Q12. The $957,266,276 on row 270 of attachment 2 to DR-ORA-104-Q6 represents the total (aggregate) work credit balance of all communities as of September 30, 2015 (including 5-year borrow) with no offset for "committed" projects. The $519.941 million on

Footnote continued on next page

accumulated work credit balances, the Rule 20A work credit allocation amount of $41.3 million that was adopted in both the 2011 GRC decision and the 2014 GRC decision is extended through 2019. Admittedly, setting work credit allocations as we have in the last two GRC cycles alone, has not yet been successful in reducing PG&E's accumulated work credit balances. But given the steps PG&E has taken to increase its capability to perform Rule 20A conversions[74] and the added scrutiny that PG&E's Rule 20A program will receive through the one-way balancing account and the audit described above, there is reason to remain optimistic. In addition, we will review the PG&E's work credit balances and annual Rule 20A work credit allocation in PG&E's next GRC proceeding.

4.1.4. Energy Supply (Section 3.1.4)

Section 3.1.4 of the Settlement Agreement addresses revenue requirement issues regarding PG&E's Energy Supply LOB.

The Settlement Agreement reduces PG&E's Energy Supply forecast expense request of $744 million to $739 million, a $5 million reduction. In

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line 6 of WP Table 18-8 the represents the total (aggregate) work credit balance of all communities as of January 1, 2015 (including 5-year borrow) and this total does reflect an offset for the forecast value of "committed" projects.

[74] Exhibit PG&E-23 at 18-5. PG&E has taken steps to increase its capability to perform Rule 20A conversions, including: Instituting a single contract to increase project efficiency with civil design and construction phases; Establishing a cross-functional team to increase program understanding and share lessons learned to mitigate potential future risk; Dedicating four full time employees to focus on customer requirements; Establishing a single contractor to develop the service lateral books and perform service lateral work thereby increasing project efficiencies; and Revising PG&E's General Conditions Agreement to facilitate municipalities' ability to get projects into the queue.

testimony, ORA proposed a reduction of $20 million, while TURN proposed a reduction of $11 million.[75]

The Settlement Agreement leaves PG&E's Energy Supply forecast capital request of $480 million unchanged. In testimony, ORA proposed no reduction, while TURN proposed a reduction of $23 million.[76]

The agreed-upon expense reductions are summarized below.

- $0.5 million for Hydro Operations (MWCs AX, KH and KI); and
- $4.2 million for seismic studies at Diablo Canyon (MWC IG).

Settling Parties note that in conjunction with the reduction of $4.2 million for seismic studies, PG&E shall continue its current practice of recording its annual costs of seismic studies in the Diablo Canyon Seismic Studies Balancing Account for review and recovery through its annual Energy Resource Recovery Account compliance proceeding.

The Settling Parties assert that the Settlement for Energy Supply reflects a reasonable compromise of the positions taken by the parties, as reflected in Chapter 2.C of the JCE (Exhibit PG&E-37).

As explained above, certain revenue requirements from other settled amounts in other PG&E lines of business are also allocated to the Energy Supply LOB. Once those allocations are incorporated into the revenue requirement, the settled outcome for Energy Supply reflects a net increase of $153 million above

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75 Settlement Agreement, Appendix A, page 2.

76 *Ibid.*

PG&E's 2016 revenue requirement, which is also $40 million less than PG&E requested in its update testimony. The table below provides this level of detail.

Pacific Gas and Electric Company
2017 General Rate Case Results of Operations
Settlement Agreement
Summary of Proposed Increase Over Adopted 2016
Electric Generation
(Millions of Nominal Dollars)

		2016	2017		2017	2017	2017
		Adopted	PG&E Proposed	Difference (Proposed vs. Adopted)	Settlement	Difference (Settlement vs. Adopted)	Difference (Settlement vs. Proposed)
Line No.		(A)	(B)	(C=B-A)	(D)	(E=D-A)	(F=D-B)
	Description						
	Expense:						
1	Operation and Maintenance	640	655	15	650	10	(5)
2	Customer Services	-	5	5	2	2	(3)
3	Administrative & General	278	291	13	272	(6)	(19)
4	Less: Revenue Credits (Other Operating Revenues (OOR) & Wheeling)	(18)	(5)	13	(6)	12	(1)
5	FF&U, Other Adjs,	(89)	39	128	37	126	(2)
6	Subtotal Expense	811	985	174	956	144	(29)
	Capital-Related:						
7	Depreciation, Decommissioning and Amortization	509	555	47	554	45	(2)
8	Taxes: State and Federal Income, Property	231	214	(17)	211	(20)	(3)
9	Federal Tax Repair Benefit Net of Flowback	(36)	(35)	1	(34)	1	0
10	Return	447	435	(11)	429	(18)	(7)
11	Subtotal Capital-Related	1,150	1,170	20	1,159	9	(11)
12	Total Electric Generation Revenue Requirement	1,961	2,155	194	2,115	153	(40)

4.1.4.1. Discussion of Energy Supply Revenue Requirement Items

Based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement, we find that the agreed-upon 2017 Energy Supply expenses and capital expenditures are reasonable and we conclude that they should be adopted.

Given the severity of California's winter storm season in 2016-2017, we note that the scope of our review of PG&E's requested revenue requirement in this GRC proceeding includes funding for PG&E's Dam Safety Program. Although responsibility for dam safety falls under the jurisdiction of the California Division of Safety of Dams (DSOD) in the Department of Water Resources, as with other utility infrastructure, this Commission authorizes expenditures pertaining to investor utility-owned dams in GRCs such as this one.

Pursuant to this responsibility, in its March 7, 2016 report in this proceeding SED highlighted relevant portions of PG&E testimony in order to provide an illustrative example of major risks and mitigation proposals regarding dam safety. The purpose of the example is to provide a yardstick by which decision-makers and intervenors can assess the many other risk mitigations that PG&E proposes in its testimony.

SED notes that PG&E operates 170 dams in Northern and Central California. In this GRC, PG&E defines Hydro System Safety risk as "the risk of failure of a PG&E dam or other water storage or conveyance facility that may result in significant damage to third parties, the environment, and/or the

Company." PG&E ranked Hydro System Safety as one its top five Electric Operations enterprise risks. The risk scenario used to score this risk is a low-probability, high-consequence event: a dam develops a major breach causing significant uncontrolled water spillage resulting in multiple lives lost, and major facility, road, and environmental damage with outages lasting more than six months.

PG&E's Dam Safety Program includes capital work that implements repairs and replacements to hydro dams and associated equipment as a result of issues identified and prioritized through ongoing analysis and inspections. PG&E explains that this program includes dam modifications to alleviate unacceptable levels of leakage through a dam, to restore the functionality of existing radial gates, drum gates, and low level outlets, and to rebuild damaged spillways, dam faces, and outlets.[77] The program additionally addresses findings and mandates from FERC and DSOD, which require formal dam safety reviews and studies to determine the condition of PG&E's dams and to assess the long term suitability for continued safe and reliable operation. In compliance with these requirements, PG&E prepares action plans, designs, and implements the necessary physical dam remediation to mitigate the risk of failure.[78]

SED's analysis resulted in two observations regarding PG&E's Dam Safety Program.

First, with respect to PG&E's 2017 GRC risk projects associated with dam licensing and mitigation work, SED observes that PG&E appears to have

[77] Exhibit PG&E-5 at 4-55.

[78] *Ibid.*

identified risk factors and ranked non-nuclear generation risks and risk mitigations in accordance with its risk assessment program.[79]

Second, SED reports on a meeting it held with DSOD, scheduled in order to get a better understanding of PG&E's dam safety issues. According to SED,[80]

> DSOD explained some of the challenges it encounters with dam operators in California. Specifically with respect PG&E's dam risk management program, DSOD expressed concerns with delays in dam mitigation work, and with PG&E's Energy Supply's organizational structure that organizes the mitigation work.
>
> DSOD based this, in part, upon its assessment of two aspects of PG&E's dam risk management program:
>
> 1. PG&E appeared to lack a structured risk portfolio management program to assess, rank, and effectively mitigate risks at its dams in a timely manner. DSOD considers development of a comprehensive risk portfolio an emerging best practice, and a more effective approach for ensuring mitigation of dam risks.
> 2. Although PG&E has hired additional staff, its current organizational structure generally impeded expedient and accountable mitigations of issues pertaining to inspections, dam-related assessments, and design/construction projects. PG&E assigns licensing coordinators to interface with regulators and inspectors. Since these Licensing Coordinators generally do not have a dam engineering background, they must arrange for the necessary engineering support to respond to issues raised by DSOD's engineers. DSOD found the

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79 "Safety and Enforcement Division Risk Assessment Section Staff Report, Pacific Gas and Electric Company (PG&E) 2017-2019 General Rate Case Application A.15-09-001" at 64.

80 *Ibid.* at 63-64.

> current structure generally leads to a reactive culture rather than a proactive one. DSOD considers permanent assignment of an engineer responsible for specific dams to be a more effective and accountable best practice. DSOD has found operators that engage in that practice are more proactive in addressing and mitigating risks.

Based on its meeting and subsequent follow-up with DSOD, SED observes that "it appears that [PG&E] Energy Supply management should undertake additional communication and coordination with DSOD to ensure that transparency of potential issues are explored in a timely manner and both parties are on the same page regarding risk profiles and evaluation."[81]

PG&E addressed SED's report and analysis regarding PG&E's Dam Safety Program in Exhibit PG&E-24 of its rebuttal testimony. PG&E acknowledges that additional communication and coordination with DSOD is necessary to establish a more effective working relationship and provide DSOD staff with a better understanding of PG&E's organizational structure, internal processes, and risk management efforts related to dam safety.[82] PG&E describes plans to meet with DSOD to discuss the issues and concerns reflected in DSOD's comments to SED staff, as well as its plans to set up regular meetings with DSOD staff to improve awareness and coordination of PG&E's dam safety-related projects and initiatives.

With respect the concerns expressed to SED by DSOD regarding PG&E delays in dam mitigation work, PG&E did not directly address this matter in its

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[81] *Ibid.* at 64.

[82] Exhibit PG&E-24 at 4-29.

rebuttal. PG&E did more broadly address the concerns expressed to SED by DSOD regarding PG&E's Energy Supply organization's organizational structure, stating:[83]

- PG&E is working to identify, develop, and implement risk-based tools and processes for more effective and efficient allocation of resources to dam safety improvements.
- PG&E is also working to develop a quantitative, portfolio-wide assessment of seismic risk at PG&E's dams.
- PG&E is working to improve the transparency of the relationship between license coordinator and engineering responsibilities.
- In early 2015, PG&E established geographic assignments within the facilities safety program, with two facilities safety engineers assigned to each of four regions within PG&E's Hydro system. PG&E has already recognized benefits in the development of closer relationships and improved communication between facilities safety engineers and local watershed staff and more continuity and accountability in tracking and addressing dam safety-related issues. PG&E expects that these benefits will become more apparent to DSOD and FERC as the geographic assignments become more established over time.

We are encouraged that SED's report in this proceeding has resulted in PG&E more proactively engaging with DSOD in order to establish a more effective working relationship. At the same time, it is incumbent on PG&E to follow up to ensure that DSOD's concerns are fully addressed. Therefore, we direct PG&E to work with DSOD and then to develop a reporting schedule and format that will enable us to monitor the progress and outcome of PG&E's discussions with DSOD regarding development of what DSOD described as a

[83] *Id.* at 4-30 to 4-31.

"structured risk portfolio management program to assess, rank, and effectively mitigate risks at its dams in a timely manner." PG&E shall report on the results of its discussions with DSOD within 60 days of the date of this decision, by sending a letter to the Director of the SED and serving a copy of that letter on the service list of this proceeding.

4.1.5. Customer Care (Section 3.1.5)

Section 3.1.5 of the Settlement Agreement addresses test year revenue requirement and other financial issues regarding PG&E's Customer Care LOB. As explained above, the settled outcome for Customer Care is allocated to the Gas Distribution, Electric Distribution, and Energy Supply lines of business so that the revenue requirement for Customer Care can be collected from PG&E's ratepayers in their gas and electric rates.

4.1.5.1. Test Year Revenue Requirement (Section 3.1.5.1)

The Settlement Agreement reduces PG&E's Customer Care 2017 forecast expense request of $429.5 million to $399 million, a $30.5 million reduction. In testimony, ORA proposed a reduction of $43 million, while TURN proposed a reduction of $103 million.[84]

The Settlement Agreement reduces PG&E's Customer Care 2017 forecast capital request of $198 million to $196.7 million, a $1.3 million reduction. In testimony, ORA proposed a reduction of $1.3 million, while TURN proposed no reduction.[85]

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[84] *Ibid.*

[85] *Ibid.*

The agreed-upon reductions are summarized below.

4.1.5.1.1. Expense Reductions

- $7.1 million for customer engagement (MWCs EZ, FK and IV);
- $14.7 million for pricing products (MWC EZ);
- $3.8 million for contact centers (MWC DK);
- $0.8 million for customer retention (MWC FK). This item is discussed further below.
- $1.0 million for metering (MWC AR);
- $3.2 million for billing, revenue and credit (MWC IS); and
- $1.3 million for information technology (MWC 2F).

4.1.5.1.2. Capital Reductions

The Settling Parties assert that the agreed-upon outcomes for the Customer Care test year revenue requirement reflects a reasonable compromise of the positions taken by the parties as reflected in Chapter 2.D of the JCE.

In addition to the major expense and capital items summarized above, the Settlement Agreement includes other settled items that have a financial impact on the final Customer Care revenue requirement. Settling Parties assert that settlement of the issues set forth below reflects a reasonable compromise of the positions taken by the parties, many of which are reflected in Chapter 2 of the JCE.

4.1.5.2. Residential Rates Reform Memorandum Account (Section 3.1.5.2)

In July 2015, the Commission issued D.15-07-001 in the Residential Rates Order Instituting Rulemaking (OIR) proceeding, which provided direction to the electric utilities on implementation of Time of Use (TOU) rate options. Among other things, the Commission ordered each utility to create a memorandum account (the Residential Rates Reform Memorandum Account, or RRRMA, for PG&E) to track costs related to implementation of the decision.[86] The Settlement Agreement addresses two issues with respect to the RRRMA: (1) recovery of costs recorded in 2015 and 2016; and (2) recovery of costs recorded in 2017 and beyond.

4.1.5.2.1. Recovery of 2015-2016 Costs

In D.15-07-001, the Commission stated that "[t]hese memo accounts would be subject to review in the utility's next GRC, with the burden on the utility to show that the expenditures were incremental, verifiable and reasonable."[87] PG&E requested recovery of the actual costs tracked in the RRRMA as of the effective date of a final decision in this proceeding. ORA and TURN recommended that PG&E should file a separate application to recover those costs. ORA and TURN both stated that these costs should be subject to after-the-fact reasonableness review by the Commission. In rebuttal, PG&E agreed that the costs booked to the RRRMA should be subject to reasonableness review by the Commission, but recommended that PG&E should seek recovery of those costs through an advice filing as opposed to through separate application.

Section 3.1.5.2.1 of the Settlement Agreement provides that PG&E may seek recovery in rates of 2015-2016 costs booked to the RRRMA through a Tier 2 advice filing filed after the Commission's issuance of a final decision in the 2017

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86 D.15-07-001, Ordering Paragraph 12.

87 *Id.* at 298.

GRC. Prior to filing the advice filing, PG&E shall share a draft of the advice filing, and an accounting of the costs to be recovered, with ORA and TURN for their comment, which PG&E shall take into account in its submission of the advice filing.

4.1.5.2.2. Recovery of 2017 and Beyond Costs

PG&E included a forecast for TOU implementation activities for 2017-2019 as part of its GRC forecast. Specifically, PG&E requested that the Commission adopt a 2017 forecast of $19.3 million in total for residential rate reform activities in 2017. PG&E forecast additional amounts for 2018 and 2019 as follows: (1) a total of $40.4 million in 2018 and; (2) a total of $46.6 million in 2019.

ORA stated that there is uncertainty regarding these costs and recommended that they be removed from the GRC and tracked in a memorandum account. In the alternative, ORA recommended that PG&E be authorized to recover up to its forecast amounts in a one-way balancing account. TURN supported ORA's position that these costs should not be included in the GRC. In the event the Commission was to allow recovery of these costs through the GRC, TURN would oppose recovery beyond what the normal post-test year mechanism would provide for 2018 and 2019. In rebuttal, PG&E recommended that the Commission establish a new two-way balancing account for recovery of these costs. In the alternative, PG&E agreed with ORA's recommendation for a one-way balancing account, though with an opportunity for PG&E to recover costs beyond the amount of its GRC forecast.

Section 3.1.5.2.2 of the Settlement Agreement authorizes PG&E to track and record costs incurred in 2017 and beyond through its RRRMA and to recover its recorded costs annually through PG&E's Annual Electric True-up (AET) advice letter filing up to a cumulative total of $57.9 million for the 2017-2019 period (the equivalent of PG&E's 2017 forecast of $19.3 million for each year). In the event that the Commission adopts a four-year GRC cycle, PG&E shall be authorized to recover an additional $19.3 million in 2020 through the AET for such activities. The Settlement Agreement also provides that ORA may audit the RRRMA. Finally, the Settlement Agreement provides that PG&E may seek recovery via Tier 3 advice filing of additional costs incurred that exceed the amounts specified in this section, subject to Commission reasonableness review and possible disallowances of costs.

4.1.5.3. Shareholder Funding for Customer Retention (Section 3.1.5.3)

ORA, Merced and Modesto IDs, and SSJID each recommended that PG&E receive no funding for customer retention work and that PG&E be required to record customer retention costs below-the-line.[88] PG&E forecast $807,000 for these activities in MWC FK.[89] Among other things, certain parties commented that PG&E's customer retention activities were for the purpose of blocking or opposing municipalization efforts,[90] that they were unnecessary, and that they may increase costs to ratepayers.[91] PG&E disagreed, stating that among other things, these activities were appropriate and helped to prevent spreading fixed costs to remaining customers as a result of uneconomic bypass.[92]

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[88] Exhibit ORA-13 at 42; Exhibit SSJID-1, Chapter 2, at 2-1 to 2-21; Exhibit MMID, Chapter 4 at 12-28.

[89] Exhibit PG&E-6 at 6-16, Table 6-5, line 2.

[90] Exhibit MMID at 14 to 16.

[91] Exhibit MMID at 1.

[92] Exhibit PG&E-6 at 6-1; Exhibit PG&E-25 at 6-7 to 6-13.

Section 3.1.5.3 of the Settlement Agreement provides for a revenue requirement reduction of $807,000 associated with the above-described work and, during the term of the 2017 GRC, provides that PG&E shall record the above-described customer retention costs below-the-line and modify its below-the-line accounting standard accordingly.

4.1.5.4. Economic Development Rate (Section 3.1.5.4)

PG&E forecasted $2.1 million in 2017 expense for Economic Development work. These expenses reside in MWC FK. Parties' recommendations regarding funding for this program are set forth in the JCE.[93] Part of the $7.1 million reduction for Customer Engagement listed above includes a $1.2 million reduction for the Economic Development program. Section 3.1.5.4 of the Settlement Agreement explains that the $1.2 million reduction takes into account and accommodates Merced and Modesto IDs' recommendation that the Commission should condition any funding for the Economic Development Rate Program on the renewal of the Economic Development Rate in Phase 2 of the GRC, consistent with the requirements of D.13-10-019.[94]

4.1.5.5. Customer Service and Outreach (Section 3.1.5.5)

NDC recommended that 70 % of PG&E's marketing, education and outreach (ME&O) budget should be allocated to low-income customers with at

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[93] Exhibit PG&E-37 Volume 1 at 2-427 through 2-430.

[94] Exhibit MMID, Chapter 6 at 30.

least two-thirds targeted towards minorities.[95] PG&E noted that funding for many ME&O budgets are set on a program-by-program basis in a number of balancing account proceedings outside the GRC.[96] PG&E generally agrees, however, that targeting low-income and minority customers through marketing and outreach are important.[97]

Section 3.1.5.5 of the Settlement Agreement targets 33% of PG&E's spending in various customer outreach areas toward communities of color and underserved communities. It requires PG&E to report in the next GRC regarding the percentage of the annual GRC funding amount authorized by the Commission for outreach and education on safety information, awareness, and emergency notifications that was used for reaching these communities. The Settlement Agreement provides that PG&E may use ethnic media, community and faith based organizations, in-language materials, and other diverse marketing strategies to reach these communities.

4.1.5.6. Customer Fees (Section 3.1.5.6)

PG&E proposed to reduce non-sufficient funds fees from the current fee of $11.00 to $7.00, on the grounds that reduced costs of notice generation, working capital and bank fees support the reduction. No party opposed the proposal.

PG&E also proposed to reduce reconnection fees and eliminate higher non-core hour fees. These reductions were largely driven by implementation of SmartMeter™ technology for residential customers, which has significantly

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[95] Exhibit NDC at 10.

[96] Exhibit PG&E-25 at 3-21.

[97] Exhibit PG&E-25 at 3-21.

lowered the cost to restore utility service. For this reason, PG&E proposes single fees of $17.50 for non-California Alternate Rates for Energy (CARE) customers and $11.25 for CARE customers. No party opposed the proposal.

Section 3.1.5.6 adopts PG&E's proposed reductions to its non-sufficient funds fees and reconnection fees.

4.1.5.7. Uncollectibles (Section 3.1.5.7)

PG&E proposed revising the methodology to calculate the uncollectibles factor. Under PG&E's proposed method, the factor would be calculated using the total net write off over ten years divided by the total revenue over ten years. ORA noted that in the 2014 GRC, the Commission approved a methodology that would use a ten-year rolling average of the yearly uncollectibles factor and recommended the Commission continue to use that methodology. Section 3.1.5.7 of the Settlement Agreement adopts ORA's recommendation.

4.1.5.8. Discussion of Customer Care Revenue Requirement and Other Financial Items

With one exception, based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement, we find that the agreed-upon 2017 Customer Care expenses, capital expenditures, and other financial items are reasonable and we conclude that they should be adopted. We agree with Settling Parties statement that, given the various parties' recommendations in this area, these provisions are supported by the record and, in light of the various compromises set forth in this Agreement, these provisions are reasonable and in the public interest.

With respect to the agreed-upon treatment of the Residential Rates Reform Memorandum Account, we find that it is neither reasonable in light of the whole record, nor consistent with law, nor in the public interest. We also note that although it is true that PG&E's 2017 GRC-related forecast revenue requirement would be reduced by $19.3 million if this aspect of the Settlement Agreement were approved, this is not a reduction in the costs faced by PG&E's customers: PG&E and the other Settling Parties have simply agreed that PG&E should recover the costs from ratepayers elsewhere, as part of a separate annual advice letter filing. For the reasons we provide below, we conclude that we should reject Section 3.1.5.2 of the Settlement Agreement.

In D.15-07-001 we directed PG&E, SCE and SDG&E to create memorandum accounts to track the costs of TOU pilots and studies, marketing, education and outreach costs, and other reasonable expenditures required to implement the decision. In doing so, we specified that the entries into these memo accounts would be subject to review in the utility's next GRC, with the burden on the utility to show that the expenditure were incremental, verifiable and reasonable.[98] In Exhibit PG&E-6, PG&E requested recovery of whatever recorded balance existed in the RRRMA as of the effective date of a decision in this GRC, plus additional forecast amounts above of $16.1 million in 2018 and $21.3 million in 2019.

While this proceeding is literally "PG&E's next GRC" after D.15-07-001, its testimony on this matter was served just two months after the Commission

[98] D.15-07-001 at 298.

adopted D.15-07-001. As such, as ORA observed in its own testimony, "as a practical matter, there is a timing issue. Parties cannot conduct a reasonableness review on costs yet to be incurred."[99] TURN concurred in its own testimony, stating "the Commission should also be very wary when PG&E starts forecasting expensive multi-year projects. While only 8 months into a 78-month process, PG&E is forecasting that it is going to cost millions to implement its residential rate reform. When a project is forecast to cost this much, this early in a process, it would be irresponsible to allow a forecast of these costs to be booked [into] rates."[100]

Despite their original concerns, ORA and TURN subsequently entered into the Settlement Agreement, which included provisions that (1) PG&E may seek recovery in rates of the 2015- 2016 costs booked to the RRRMA through a Tier 2 advice filing filed after the Commission's issuance of a final decision in the 2017 GRC, and (2) PG&E shall be authorized to track and record costs incurred in 2017 and beyond for residential rate reform implementation including default time-of-use through its RRRMA, and shall be authorized to recover its recorded costs annually through PG&E's Annual Electric True-up (AET) advice letter filing up to a cumulative total of $57.9 million for the 2017 -2019 period (the equivalent of PG&E's 2017 forecast of $19.3 million for each year).

D.15-07-001 directed that the balances in the RRRMA would be subject to review with the burden on the utility to show that the expenditures were

[99] Exhibit ORA-13 (Morse) at 25.

[100] Exhibit TURN-8 at 17. TURN cites PG&E WP 3-24 through 3-27 to estimate that PG&E's RRRMA cost request in this proceeding totals $103.9 million for the 2015-2019 period.

incremental, verifiable and reasonable. An advice letter process an inappropriate substitute for such a review. It is not the role of settling parties to decide amongst themselves that PG&E may be relieved of the obligation created by D.15-07-001. As demonstrated by the testimony of ORA and TURN, this outcome is also not supported by the record in this proceeding. Since it is unsupported by the record, and contrary to D.15-07-001, this outcome is also not in the public interest. For these reasons, we conclude that Section 3.1.5.2 of the Settlement Agreement should not be approved. PG&E may file a standalone application for recovery of recorded costs, or may seek recovery in its next GRC application.

4.1.6. Shared Services and IT (Section 3.1.6)

Section 3.1.6 of the Settlement Agreement addresses revenue requirement issues regarding PG&E's Shared Services and IT lines of business. Shared Services and IT activities involve common costs that benefit all of PG&E's lines of business.

The Shared Services portion of PG&E's revenue requirement includes:

- Safety Department
- Transportation Services
- Materials
- Sourcing
- Real Estate
- Environmental Program
- Enterprise Programs

The IT portion of PG&E's revenue requirement includes the following "portfolios" of work:

- The Business Technology Projects Portfolio

- The Foundational Technology Portfolio
- The Cybersecurity Portfolio
- The IT Baseline Operations Portfolio

The Settlement Agreement reduces PG&E's Shared Services and IT forecast expense request of $429.5 million to $422 million, a $7.5 million reduction. In testimony, ORA proposed a reduction of $39 million, while TURN proposed a reduction of $17 million.

The Settlement Agreement reduces PG&E's Shared Services and IT forecast capital request of $499 million to $494 million, a $5 million reduction. In testimony, ORA proposed no reduction, while TURN proposed a reduction of $102 million.

The agreed-upon reductions are summarized below.

4.1.6.1.1. Expense Reductions

- $0.9 million for sourcing (MWC JV);
- $3.3 million for real estate (MWC BI);
- $0.7 million for environmental programs (MWC JE); and
- $2.5 million for the Enterprise Corrective Action Program (CAP) (MWC AB).

4.1.6.1.2. Capital Reduction

- $5.4 million for real estate (MWC 23).

The Settling Parties assert that the settlement for Shared Services reflects a reasonable compromise of the positions taken by the parties as reflected in Chapter 2.E of the JCE.

4.1.6.2. Technical Assistance for Suppliers

In Chapter 6 of Exhibit PG&E-7, PG&E describes Supplier Diversity Initiative, which supports PG&E's mission to include small women-, minority-, service disabled veteran and lesbian, gay, bisexual, and transgender-owned business enterprises in the supply chain.[101] These small and diverse businesses are collectively referred to as diverse business enterprises (DBE). Within its Supplier Diversity Initiative, PG&E forecast $1 million for its "Technical Assistance Program" (TAP) in 2017. PG&E states that TAP offers training and education to DBEs of all sizes, with workshops conducted in partnership with community-based organizations.

NDC stated that "PG&E must commit funds and resources to technical assistance and capacity building programs designed to help minority suppliers better serve PG&E and compete in the service territory. This will allow minorities to overcome racial barriers, and create a better equipped pool of diverse suppliers to serve the utility."[102]

PG&E responded in rebuttal testimony that collaborating with community partners on training, outreach and educational grants is currently an integral part of PG&E's operations and that the Company already supports a broad range of diverse business enterprise technical assistance and capacity building initiatives in collaboration with different community organizations.[103]

Section 3.1.6.2 of the Settlement Agreement provides that PG&E shall invest at least $800,000 annually toward TAPs (MWC JL) that focus on developing small, minority-owned businesses. PG&E will work with NDC and other interested parties to discuss the effectiveness of TAP expenditures, and

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[101] Exhibit PG&E-7, Chapter 5 at 5-1, 5-2 and 5-11.

[102] Exhibit NDC at 15.

[103] Exhibit PG&E-26 at 5-5 and 5-10.

discuss community-based organizations that have experience helping small businesses build their capacity.

Settling Parties assert that settlement of this issue reflects a reasonable compromise of the positions taken by the parties. Settling Parties state that, given the parties' recommendations in this area, this provision is supported by the record and, in light of the various compromises set forth in this Agreement, this provision is reasonable and in the public interest.

4.1.6.3. Discussion of Shared Services and IT

Based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement, we find that the agreed-upon 2017 Shared Services and IT expenses and capital expenditures are reasonable and we conclude that they should be adopted.

4.1.7. Human Resources (Section 3.1.7)

Section 3.1.7 of the Settlement Agreement reduces PG&E's HR expense forecast in two areas, HR department costs, and HR companywide expenses.

First, HR department cost is reduced from $61.4 million to $60.5 million, a $0.9 million reduction.

Second, HR companywide expense is reduced from $809 million to $726 million, an $83 million reduction. ORA proposed a $98 million reduction, and TURN proposed a $131 million reduction. The agreed-upon reductions are listed below:

- $5.2 million for the medical and other benefits programs ($430 million proposed, reduced to $425 million);

- $2.6 million for various non-qualified pension and defined contribution plans;
- $1.1 million for workers' compensation ($43 million proposed, reduced to $41.9 million);
- $2.1 million for Workforce Transition Program ($17 million proposed, reduced to $14.9 million); and
- $72.3 million for the STIP for non-officers ($147 million proposed, reduced to $75 million).

The Settling Parties assert that the Settlement for HR reflects a reasonable compromise of the positions taken by the parties as reflected in Chapter 2.F of the JCE.

4.1.7.1. Discussion of HR Costs

The most noteworthy of the settled outcomes summarized above is the agreement to reduce ratepayer funding for the STIP for non-officers from $147 million to $75 million, a reduction of $72.3 million. In their testimony, ORA and TURN proposed larger reductions, $90 million and $103 million, respectively. This matter was also a prominent topic at the Settlement Workshop because of the interrelationship between the STIP and safety.

In testimony, PG&E explained that its employee compensation is divided into two categories, Foundational Compensation and At-Risk Compensation.[104]

Foundational compensation at PG&E includes an employee's base pay, as well as pension and benefits. This is the portion of an employee's compensation designed to provide a stable income, as well as health, wellness and retirement

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[104] The summary in the following paragraphs is quoted from Exhibit PG&E-43, "Late Filed Exhibit on Executive Compensation and Safety" at 4.

benefits. Foundation pay, by design, is not meant to be at-risk. For executive employees, the foundational piece constitutes about 40 % of their overall compensation. Most of the costs of foundational compensation for all PG&E employees (including executives) are included in PG&E's 2017 GRC revenue requirement.

As defined by PG&E, at-risk compensation is designed to be conditioned on one or more aspects of the employee's and/or the Company's level of performance against set goals. For executive employees, there are two main at-risk components of compensation—the STIP and the Long Term Incentive Plan (LTIP). Together, these at-risk components of compensation constitute about 60 % of compensation for executives. Costs of at-risk compensation for executives are shareholder funded and are not included in PG&E's 2017 GRC revenue requirement.

The Short Term Incentive is PG&E's annual variable incentive pay plan. In addition to its executives, every PG&E supervisor, manager, and director participates in STIP. In its testimony, PG&E describes the STIP as a program with metrics established each calendar year (Plan Year) by the Compensation Committee of the PG&E Corporation Board of Directors. The program provides eligible employees the opportunity to earn annual cash payments based on their individual performance and the Company's achievement relative to specified performance goals measured over the Plan Year.[105] PG&E states that an incentive program like STIP is a typical component of a company's compensation package

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[105] Exhibit PG&E-8 at 3-11.

and is an expected component of the total pay package for professional and management employees.[106]

The differences between the litigation positions of PG&E, ORA and TURN have to do with disagreements over the extent to which the non-executive portion of the STIP should be funded by ratepayers or by PG&E shareholders. PG&E proposed 100% ratepayer funding for the non-executive portion of STIP in 2017. ORA and TURN proposed that shareholders fund certain components of the STIP, arguing that ratepayers do not benefit from certain of the metrics tracked and rewarded by the STIP, such as PG&E's financial performance.

The settled outcome would have the result that PG&E shareholders do fund a portion of the STIP. This outcome is consistent with the Commission's position on the STIP in PG&E's 2014 GRC, where the Commission concluded that offering employee compensation in the form of incentive payments is useful for recruiting and retaining skilled professionals and improving work performance, while noting that ratepayers derive benefits from various elements of the STIP and should bear a reasonable level of costs commensurate with benefits, although PG&E shareholders benefit from STIP as much as or more than do ratepayers.[107] The Commission also concluded that adopting a sharing of STIP costs between ratepayers and shareholders is consistent with prior Commission decisions where ratepayer funding of employee incentive

[106] *Id*. at 3-15.

[107] D.14-08-032, Conclusion of Law 245.

compensation was authorized but where ratepayers did not bear the entire burden of such costs.[108]

Based on filed testimony and comparison of parties' litigation positions with the settled outcome, as well as discussion at the Settlement Workshop, we find that the settled outcome regarding the revenue requirement for PG&E's STIP is reasonable and conclude that it should be adopted. We discuss the non-financial aspects regarding the structure of the STIP later in this decision.

With respect to the non-STIP HR matters addressed in the Settlement Agreement, based on our review of parties' positions as summarized in the JCE, as well as the underlying testimony, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement, we find that those agreed-upon 2017 HR expenses and capital expenditures are reasonable and we conclude that they should be adopted.

4.1.8. A&G Expense (Section 3.1.8)

Section 3.1.8 of the Settlement Agreement reduces PG&E's A&G expense forecast in two areas, A&G department costs, and A&G companywide expenses.

First, A&G department cost is reduced from $186.8 million to $185.1 million, a $1.7 million reduction.

Second, A&G companywide expense is reduced from $144 million to $136 million, a $7.6 million reduction. ORA proposed a $5.5 million reduction, and TURN proposed an $11.8 million reduction.

The agreed-upon reductions are listed below:

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108 *Id.*, Conclusion of Law 246.

4.1.8.1. A&G Department Cost Expense Reductions

- $0.4 million for the Finance organization;
- $0.8 million for Regulatory Affairs;
- $0.5 million for Executive Offices and Corporate Secretary; and
- $0.1 million for Corporate Affairs.

4.1.8.2. A&G Companywide Expense Reductions

- $0.1 million for bank fees;
- $1.2 million for directors and officers liability insurance;
- $3.4 million for general liability insurance;
- $0.5 million for non-nuclear property insurance;
- $2.2 million for nuclear property insurance; and
- $0.3 million for Director fees and expenses.

The Settling Parties assert that the settlement for A&G reflects a reasonable compromise of the positions taken by the parties as reflected in Chapter 2.G of the JCE.

4.1.8.3. Discussion of A&G Issues

Based on our review of parties' positions as summarized in the JCE, as well as the underlying testimony, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement, we find that the agreed-upon 2017 Administration and General expenses are reasonable and we conclude that they should be adopted.

4.1.9. Technical and Accounting Issues (Section 3.1.9)

Section 3.1.9 of the Settlement Agreement provides detail regarding PG&E's Technical and Accounting proposals. The treatment of these issues in the Settlement Agreement is addressed below.

4.1.9.1. Depreciation (Section 3.1.9.1)

The annual depreciation of a capital investment is recognized as an expense item in utility revenue requirements. Depreciation expense represents the return of invested capital, providing a source of funds which, in part, may be used to replace and expand utility capital assets. In this proceeding, the agreed-upon test year revenue requirement increase that results from the Settlement would be higher if not for a reduction of $67 million of PG&E's originally-requested depreciation expense due to agreed-upon changes to PG&E's requested net salvage rate depreciation parameters for certain asset classes. These changes are reflected in Section 3.1.9.1 of the Settlement Agreement. Of the $230.6 million in reductions achieved from PG&E's 2017 proposed revenue requirement to the Settlement, that $67 million represents 29% of the total.

Settling Parties state that PG&E presented a detailed depreciation study for mass asset accounts, proposing updated depreciation parameters (i.e., net salvage rates, average service lives, and mortality curves) in support of its request for depreciation expense.[109] ORA accepted most of PG&E's proposed depreciation parameters, but disagreed with the size of increases in net salvage rates for five accounts based on its interpretation of the principal of gradualism.[110] ORA also proposed slightly longer service lives for two accounts.

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[109] *See,* Exhibit PG&E-10, Chapter 10.

[110] In past GRCs, the Commission has invoked a principle of "gradualism" where there is a recognized need to revise estimated depreciation parameters, but where the revision is allowed to occur incrementally over time rather than all at once. Applying gradualism thus limits the approved increase in depreciation expense that would otherwise be warranted, all else being

Footnote continued on next page

TURN proposed more significant changes to net salvage percentages and to service lives and curves. CUE also proposed significant changes to service lives based on PG&E's replacement activity for poles and gas mains. TURN and A4NR also proposed to lengthen the service life on generation assets.

The Settlement Agreement reduces PG&E's depreciation request by $67 million by modifying the requested net salvage rate for certain asset classes, but otherwise leaves intact PG&E's recommendations for service lives and curves. The 2017 depreciation parameters resulting from the Settlement Agreement are shown in the Settlement Agreement, Appendix C.

Settling Parties assert that the Settlement Agreement is favorable to current customers because the agreed-upon changes in parameters result in an overall lower revenue requirement increase to customers than the adopted changes in PG&E's 2014 GRC, and are, therefore, more gradual than the changes the Commission previously found reasonable in the 2014 GRC. Settling Parties assert that the Settlement Agreement is reasonable because the study was performed by the same experts using the same methods as the study the Commission found generally defensible in the last GRC.

4.1.9.2. 2015 and 2016 Capital Expenditures (Section 3.1.9.2)

The test year revenue requirement increase that results from the Settlement Agreement also reflects adoption of ORA's recommendation for a reduction to

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equal, and mitigates the short-term impact of large changes in depreciation parameters. The Commission has stated that it is also advisable to be cautious in making large changes in estimates of service lives and net salvage for property that will be in service for many decades, as future experience may show the current estimates to be incorrect. *See* D.14-08-032 at 598.

PG&E's 2015 capital expenditure forecast, largely based on 2015 recorded (not forecast) costs, as well as additional reductions in response to TURN's recommendations regarding gas distribution, totaling $186 million. In its rebuttal testimony, PG&E opposed ORA's recommendation as inconsistent with the RCP, which calls for recorded data from 2014 to be the basis for preparing the forecast for the test year.[111]

The agreed-upon test year revenue requirement additionally incorporates reductions to PG&E's 2016 capital expenditure forecast of $31 million, in response to recommendations of ORA and TURN.

Settling Parties assert that the settlement outcome in Section 3.1.9.2 is reasonable as an accommodation to ORA and TURN.

4.1.9.3. Income and Property Taxes (Section 3.1.9.3)

Section 3.1.9.3 of the Settlement Agreement adopts PG&E's forecast of income and property taxes, which was not opposed by any party.

In the course of settlement negotiations TURN raised the issue of tax accounting changes for repairs, an issue which has also arisen in recent GRCs of the other large utilities. This issue had not been raised in testimony. Settling Parties note that PG&E had agreed in the past to hold customers indifferent for Federal income tax purposes for tax accounting changes made prior to the date the Commission was informed of such changes.[112] In the Settlement Agreement,

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[111] Exhibit PG&E-20 at 1-7 to 1-9.

[112] Settling Parties appear to be referring to PG&E Tax Act Memorandum Accounts (Gas and Electric), which track and record on a CPUC-jurisdictional, revenue requirement basis: (a) decreases in revenue requirement resulting from increases in its deferred tax reserve; and (b) other direct changes in revenue requirement resulting from taking advantage of the 2010

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consistent with its prior treatment of customers on these matters, PG&E has agreed to ORA and TURN's proposal for a Tax Repair Memorandum Account to track any future revenue requirement reductions (or increases) that might result from new tax accounting changes. The Settlement Agreement provides for the following:

> PG&E shall create a two-way Tax Repair Memorandum Account (TRMA) to track during the term of this GRC the impact on the California Public Utilities Commission (CPUC) jurisdictional revenue requirement authorized in this proceeding resulting from:
>
> (1) any new income tax accounting method change associated with the Internal Revenue Service (IRS) or California Franchise Tax Board (CFTB) for tax years 2017 through 2019 (and 2020, if a third post-test year is authorized by the Commission for PG&E), and;
>
> (2) any changes in Federal or California tax law, final or temporary regulations or other IRS/CFTB administrative guidance issued for reliance by taxpayers that impacts the determination of repair deductions for tax years 2017-2019 (and 2020, if a third post-test year is authorized by the Commission for PG&E).
>
> The Tax Repair Memorandum Account shall remain open to reflect these changes for tax years 2017 – 2019 (and 2020, if a third post-test year is authorized by the Commission for PG&E) until closed by approval of a Tier 2 advice filing.
>
> Any expansion or extension of bonus depreciation during the term of this GRC shall be addressed through the existing Tax Act Memorandum Account (TAMA) mechanism, the same procedure as was used in PG&E's last GRC.

New Tax Relief Act, the American Taxpayer Relief Act of 2012 and the Tax Increase Prevention Act of 2014.

Settling parties note that similar accounts have been adopted for the other large utilities. We discuss this proposal at the conclusion of this section.

4.1.9.4. Customer Deposits, Rate Base, and Related Issues (Section 3.1.9.4)

4.1.9.4.1. Customer Deposits

In Section 3.1.9.4 of the Settlement Agreement, the Settling Parties agree to adopt ORA and TURN's methodology to use a short-term interest rate of 1.7% for customer deposits. The 1.7% is a compromise between TURN's estimate of 1.4% and ORA's estimate of 2.05%. This results in a reduction of $6.4 million in the forecast revenue requirements. This reduction may be subject to adjustment prospectively, based on the results of the next Cost of Capital (COC) decision.

The Settlement Agreement provides for continuation of the interim revenue requirement adjustment for customer deposits, midway between the ORA and TURN recommended reductions. The Settlement Agreement also provides that, pending the result in the COC decision, this adjustment is subject to revision prospectively as of the date of such decision. Settling Parties assert that these provisions of the Settlement Agreement term are reasonable as they are essentially a continuation of the result in the 2014 GRC.[113]

4.1.9.4.2. Working Cash

PG&E states in testimony that working cash is a capital component of gas distribution, electric distribution and electric generation rate base, and is composed of two elements: (1) working funds required for day-to-day operations; and (2) funds used to pay operating expenses in advance of receiving

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[113] D.14-08-032, at 627-630.

customer payments. PG&E explains that these funds are included in rate base to compensate PG&E's investors for the use of funds they provide.[114]

In its testimony, PG&E requested that the Commission adopt its forecast of working cash, which consisted of $172.3 million for electric distribution, $108.7 million for gas distribution and $208.9 million for electric generation. These working cash totals consisted of both an operational cash requirement and a working cash component resulting from a lead-lag study.

ORA recommended a reduction in purchased power expense, as reflected in the lead-lag study, from $5.018 billion to $4.275 billion (resulting in a $22.1 million reduction in working cash). ORA argued that its reduction to purchased power expense, which was based on the most recent ERRA forecast of test year purchased power expense, better reflects PG&E's reduced future obligations. TURN agreed with ORA's purchased power adjustment. TURN also proposed adjustments to goods and services lag and various operational cash items, including accounts receivables, prepayments, and Diablo Canyon refueling costs. In total, TURN's adjustments reduced PG&E's working cash request by an additional $94.5 million.

Settling Parties agreed to use ORA and TURN's forecast of $4.275 billion for purchased power expense in the lead-lag calculation, and to adopt 26 days for the goods and services lag. This is a compromise between TURN's, ORA's and PG&E's forecast and is equivalent to the figure adopted in PG&E's 2014 GRC.

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114 Exhibit PG&E-10 at 13-1.

Settling Parties state that the adoption of these positions favors lower costs for customers and should be adopted.

4.1.9.4.3. Fuel Oil

Settling Parties agree to adopt PG&E and ORA's forecast of $0 for fuel oil inventory, stating that this settlement follows the treatment of past Commission decisions on fuel inventory and should be approved by the Commission.

4.1.9.5. Other Operating Revenue (Section 3.1.9.5)

Other Operating Revenue (OOR) include items such as rent from electric and gas properties, field collection and reconnection fees, return to maker check charges, timber sale receipts, sales of water for power, transmission wheeling service fees, gross revenues reimbursing PG&E for work incurred at the request of others, and other miscellaneous service revenues.[115] PG&E explains that OOR is revenue that PG&E receives from transactions not directly associated with the distribution, generation, or sale of electric energy or natural gas. Revenues from these transactions are generated through, and supported by, activities whose distribution and generation related costs are included in the proposed distribution and generation revenue requirements in this GRC.

These revenues are estimated separately and subtracted from the revenue requirement because OORs reduce the amounts that need to be collected from customers through rates charged for gas and electric service.

ORA proposed an increase in OOR of $13.2 million by using 2015 recorded data to forecast certain OOR items, rather than 2014 base year data. TURN

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[115] Exhibit PG&E-10 at 17-1.

agreed with ORA's recommendation and proposed an additional increase of $13.5 million based on using a different methodology to forecast a number of OOR items.

In rebuttal, PG&E argued against ORA's selective use of post-base year data and argued that ORA's approach was inconsistent with the RCP, which directs the use of base year data in forecasting test year estimates. PG&E also argued against TURN's assertion of additional OOR on the grounds that TURN was selectively using data where it would increase OOR, but not taking into account circumstances where the data would suggest lower OOR.

The Settling Parties agreed that ORA's OOR recommendation, which increases PG&E's OOR forecast by $12.7 million for 2017, shall be adopted. As shown in Section 3.1.9.5, the settlement amount for the GRC OOR will be $130.7 million in 2017. Settling Parties state that increasing PG&E's test year forecast to the levels recommended by ORA represents a reasonable compromise of the differing recommendations of the parties.

4.1.9.6. Allocation of Common Costs (Section 3.1.9.6)

Section 3.1.9.6 of the Settlement Agreement approves PG&E's proposed allocation of common costs (A&G expenses and common plant) for use in other, non-GRC Commission ratemaking mechanisms. Settling Parties state that this allocation was not opposed, except by MCE,[116] and recommend that it be approved by the Commission.

[116] Exhibit MCE-Errata to Testimony of Marin Clean Energy at 2. Settling Parties state that the resolution of MCE's issues is discussed in Section 3.2.7.2 of the Settlement Agreement. We

Footnote continued on next page

4.1.9.7. Capitalization Rates (Section 3.1.9.7)

Section 3.1.9.7 of the Settlement Agreement adopts PG&E's proposed capitalization methodology. For purposes of calculating the revenue requirements, the 2017 forecast capitalization rates are 34.35% for STIP and 42.43% for Remaining Vacation, Workers' Compensation, and Benefits.

PG&E's proposed capitalization rates are adopted for the term of the 2017 GRC for A&G departments of 12.23% for labor, 13.49% for materials and supplies, and 17.37% for Third Party Claims payments.

Settling Parties state that these provisions were not contested by any party, and recommend that they should be adopted.

4.1.9.8. Results of Operations Model (Section 3.1.9.8)

Section 3.1.9.8 of the Settlement Agreement provides that, unless changed by the terms of this Agreement, the underlying assumptions and methods used in PG&E's Results of Operations model to compute PG&E's revenue requirements, including cost allocations to unbundled cost categories (UCCs), as set forth in Exhibit PG&E-10 are adopted. This provision reflects the fact that PG&E's RO modeling assumptions were generally undisputed.

4.1.9.9. Discussion of Technical and Accounting Issues

4.1.9.9.1. Depreciation

As noted above, the settled outcome regarding depreciation expense represents a sizable portion of the total revenue requirement reduction achieved

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address that section of the Settlement Agreement later in this decision as part of our discussion of non-financial issues.

by the Settling Parties. In deciding whether or not to approve this aspect of the Settlement Agreement, we reiterate concerns we have raised in prior GRC proceedings: we must acknowledge that adopting reduced depreciation cost estimates to achieve a lower revenue requirement for the current test year essentially increases the burden on future ratepayers, who will make up any deferred depreciation costs over time. Our goal is therefore to balance the equities between current and future ratepayers.

Settling Parties assert that the Settlement Agreement is favorable to current customers because the agreed-upon changes in parameters result in an overall lower revenue requirement increase to customers than the changes adopted in PG&E's 2014 GRC, and are, therefore, more gradual than the changes the Commission previously found reasonable in the 2014 GRC. In other words, since the 2014 GRC decision was relatively less gradual, this GRC decision should be relatively more gradual so that the equities afforded current and future ratepayers are in some sense balanced out. We accept Settling Parties' reasoning here, and find that the settled outcome regarding the revenue requirement for depreciation expense is reasonable, and conclude that it should be adopted.

4.1.9.9.2. Tax Repair Memorandum Account

Commission precedent supports a policy of requiring the utilities subject to our jurisdiction to establish memorandum accounts to track the various costs and benefits of newly enacted tax law. In 2011, following passage of the federal Tax Relief Act, the Commission adopted Resolution L-411A in order to "preserve the opportunity for the Commission to decide at a future date whether some of the impacts of the Tax Relief Act, not otherwise reflected in rates, ought to be reflected in future rates, without having to be concerned with issues of retroactive ratemaking."[117] The Tax Relief Act created the likelihood of large and unexpected decreases in tax expense for the utilities which, due to the timing of Commission rate cases, created the possibility that benefits of the tax decrease might not accrue to ratepayers in the same way they would if the tax decrease had been expected. The Commission's solution to this challenge was to direct certain utilities, including PG&E, to establish memorandum accounts in order to allow the Commission to determine at a future date whether rates should be changed, without the impediment of claims of retroactive ratemaking.

Based on that precedent, we agree with Settling Parties that PG&E should create a memorandum account to track differences between forecast and recorded tax expenses. However, we specify here that PG&E should establish a memorandum account that tracks all such differences, not just changes affecting repair deductions as proposed by the Settling Parties. Therefore, consistent with our identical orders in the SDG&E and SoCalGas Test Year 2016 proceeding and the Liberty Utilities Test Year 2016 GRC,[118] PG&E shall establish a two-way tax memorandum account to track any revenue differences resulting from the differences in the income tax expense forecasted in this proceeding, and the tax expenses incurred during the 2017-2019 GRC period. The purpose of this memorandum account is to increase the transparency of PG&E's incurred and forecasted income tax expenses to the Commission, so that the Commission can

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[117] Resolution L-411A at 3.

[118] D.16-12-024, Ordering Paragraph 6.

more closely examine revenue impacts caused by PG&E's implementation of various tax laws, tax policies, tax accounting changes, or tax procedure changes. This will help the Commission review the reasonableness of PG&E's election of various tax options, such as various tax policies, tax procedures, or tax accounting changes. The memorandum account shall have separate line items detailing the differences between tax expenses forecasted and tax expenses incurred, specifically resulting from (1) net revenue changes, (2) mandatory tax law changes, tax accounting changes, tax procedural changes, or tax policy changes, and (3) elective tax law changes, tax accounting changes, tax procedural changes, or tax policy changes. The account shall remain open and the balance in the account shall be reviewed in every subsequent GRC proceeding until a Commission decision closes the account.[119]

As we have required of SCE, SDG&E and SoCalGas, PG&E shall notify the Commission of any tax-related changes, any tax-related accounting changes, or any tax-related procedural changes that materially affect, or may materially affect, revenues. Our reference to "materially affect" means a potential increase or decrease of $3 million or more. The failure to disclose such changes in a timely fashion undermines the integrity of the regulatory process, and may amount to a violation of Rule 1.

Finally, we find that the establishment of a memorandum account is consistent with Resolution L-411A at 13 in which the Commission stated: "we believe that an even handed approach to regulation requires us to consider,

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[119] This provision differs from the proposal in the Settlement Agreement, which would have provided for closure of the account via approval of a Tier 2 advice filing.

when there has been a large and unexpected decrease in expenses between rate cases, whether it is appropriate to establish a memorandum account to allow for a future decrease in rates."

4.1.9.9.3. Other Technical and Accounting Matters

With respect to the additional matters addressed in the Settlement Agreement, based on our review of parties' positions as summarized in the JCE, as well as the underlying testimony, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement, we find that the agreed-upon resolutions of the technical and accounting issues described above are reasonable and we conclude that they should be adopted.

4.1.10. Balancing and Memorandum Accounts (Section 3.1.10)

In opening testimony, PG&E proposed that a variety of existing balancing and memorandum accounts be retained or closed. PG&E did not originally propose the creation of any new accounts. For the most part, PG&E's recommendations were unopposed. However, some parties opposed some of PG&E's proposals to close balancing accounts. For instance, A4NR opposed PG&E's recommendation to close the Diablo Canyon Seismic Studies Balancing Account. Other parties, such as EDF, proposed the adoption of new balancing accounts. Section 3.1.10 of the Settlement Agreement summarizes the various agreements on balancing and memorandum accounts.

4.1.10.1. Accounts to Be Retained

For the five accounts PG&E proposed to retain, no party opposed PG&E's recommendation. Accordingly, the Settlement Agreement retains the following five accounts:

- Major Emergencies Balancing Account;

- Vegetation Management Balancing Account and associated Incremental Inspection and Removal Cost Tracking Account;
- Nuclear Regulatory Rulemaking Balancing Account;
- Hydro Relicensing Balancing Account; and
- Tax Act Memorandum Account.

PG&E also requested closure of two existing accounts that, under the Settlement Agreement, are instead retained in some form.

First, as noted above, A4NR opposed PG&E's closure of the Diablo Canyon Seismic Studies Balancing Account. The Settlement Agreement adopts A4NR's recommendation to continue the use of this account.

Second, as also noted above, ORA and TURN opposed PG&E's proposal that would have resulted in elimination of the Residential Rate Reform Memorandum Account.[120] The Settlement Agreement adopts ORA's proposal to continue the use of this memorandum account.

4.1.10.2. Accounts to be Eliminated

No party opposed PG&E's request to close the following seven accounts and the Settlement Agreement would eliminate these accounts:

- Smart Grid Pilot Deployment Project Balancing Account
- San Francisco Incandescent Streetlight Replacement Memorandum Account
- Photovoltaic Program Memorandum Account
- Energy Data Center Memorandum Account
- Dynamic Pricing Memorandum Account

[120] Exhibit ORA-13 at 24-25; Exhibit TURN-8 at 15.

- SmartMeter™ Opt-Out Balancing Account
- Affiliate Transfer Fee Accounts

PG&E also proposed discontinuing the Gas Leak Survey and Repair Balancing Account, arguing that, consistent with objectives of test year ratemaking, balancing accounts should not recover ongoing costs of operations that can be reasonably forecasted.[121] CFC argued that the account should continue until such time that PG&E determines an annual level of expenditure that would sustain the distribution system in perpetuity.[122] The Settlement Agreement adopts PG&E's position.

Parties also proposed a number of new accounts that were listed in PG&E's rebuttal testimony but the Settlement Agreement does not adopt. CUE proposed balancing accounts for pole replacement and analysis.[123] PG&E did not oppose funding the programs based on traditional ratemaking but noted that a balancing account was not appropriate given the fact that the costs were not volatile or outside PG&E's control.[124] TURN also proposed a balancing account for a surge arrester program.[125] PG&E noted that this account was inappropriate given that the costs were not volatile or outside PG&E's control.[126] The Settlement Agreement does not adopt balancing accounts for these programs.

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121 Exhibit PG&E-3 at 6C-3.

122 Exhibit CFC-7-Leak Management Corrective Maintenance Expenses at 14-15.

123 Exhibit CUE-8-Errata to Prepared Direct Testimony of David Marcus at 35.

124 Exhibit PG&E-31 at 9-3 to 9-4, Table 9-1; Exhibit PG&E-22 V2, Chapter 6C; Exhibit PG&E-24, Chapter 3; Exhibit PG&E-23 V1, Chapters 6 and 8.

125 Exhibit TURN-3 at 17; Exhibit PG&E-31 at 9-4, Table 9-1; Exhibit PG&E-23 V1, Chapter 6.

126 Exhibit PG&E-31 at 9-4, Table 9-1; Exhibit PG&E-23 V1, Chapter 6, at 6-13.

4.1.10.3. Accounts to Be Created

Certain Settling Parties requested that two new accounts be created. Earlier in this decision, we also directed creation of a new balancing account.

First, as discussed earlier in this decision, the Settling Parties agreed that the Settlement Agreement should provide for establishing a new "Tax Repair Memorandum Account" (see Section 3.1.9.3 of the Settlement Agreement). We authorized creation of such an account, albeit in modified form, in Section 4.1.9.9.2 of this decision.

Second, in response to a recommendation from EDF, the Settlement Agreement presents a New Environmental Regulatory Balancing Account for gas distribution.[127] However, this new environmental account for gas distribution is one of the two contested provisions set forth in Article 4 of the Settlement Agreement. We resolve that issue later in this decision.

Third, earlier in this decision, we directed PG&E to establish a Rule 20A balancing account that tracks the annual capital and expense costs for Rule 20A undergrounding projects.

4.1.10.4. Affiliate Transfer Fees (Section 3.1.10.4)

In another proposal related to balancing accounts, in its testimony PG&E proposed a simplification to the accounting procedures for affiliate transfer fees. Pursuant to D.96-11-017, the electric and gas Affiliate Transfer Fees Accounts (ATFA) track and record employee transfer fees paid to PG&E by its holding company and affiliates. Today, on an annual basis through the Annual Electric

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[127] Exhibit EDF-1-Opening Testimony O'Connor at 18-19.

True-up and Annual Gas True-up, the balance in the electric account is transferred to the Distribution Revenues Adjustment Mechanism (DRAM) and returned to customers while the balance in the gas account is transferred to the Core Fixed Cost Account (CFCA) and Noncore Customer Charge Account (NCA) and returned to customers.

PG&E proposes simplifying the return of these transfer fees to customers by eliminating a number of steps in the accounting procedures. Rather than recording these fees in the ATFAs and transferring the balance to the DRAM/CFCA/NCA for return to customers, PG&E proposes to record these fees directly to the DRAM/CFCA/NCA and eliminate the electric and gas ATFAs. A new, separate accounting procedure will be added to the DRAM/CFCA/NCA to ensure these costs are easily identifiable and transparent.

No party opposed this proposal. Section 3.1.10.4 of the Settlement Agreement adopts PG&E's proposal.

4.1.10.5. Discussion of Balancing and Memorandum Accounts

We approve the agreed-upon outcomes summarized above regarding retention and elimination of balancing accounts. PG&E correctly characterizes balancing accounts as being appropriate in circumstances where costs are volatile or outside the utility's control, but not in circumstances where those conditions are not present.

As noted above, we resolved Settling Parties' request to create a tax-related memorandum account earlier in this decision, and later in this decision we resolve the contested question of whether or not PG&E should be authorized to create a New Environmental Regulatory Balancing Account for gas distribution.

Finally, we also direct that PG&E create one additional balancing account, pursuant to our discussion and resolution of Rule 20A undergrounding matters earlier in this decision. We stated above that we expect that the entire annual amount that we authorize PG&E to spend on Rule 20A projects will in fact be spent on those projects, and only for Rule 20A projects. We also stated that in the event that reasons specific to the Rule 20A program prevent full expenditure of these funds in a particular year, we will require PG&E to track the unspent amounts so that they are spent on Rule 20A projects in future years. The record in this proceeding shows that Rule 20A costs can be volatile, and as least to some extent, outside PG&E's control. Therefore, we conclude that it is appropriate to direct PG&E to establish a one-way Rule 20A balancing account that tracks the annual capital and expense costs for Rule 20A undergrounding projects, on a forecast and recorded basis. Overcollected balances shall remain available for future Rule 20A projects. If the account is undercollected at the conclusion of the 2017-2019 GRC cycle, the account shall be examined in PG&E's 2020 GRC proceeding. Depending on the reason or reasons for the undercollection, PG&E shareholders shall be at risk for such balances.

4.1.11. Discussion of Test Year and Post-Test Year Revenue Requirements

A recurrent theme in the comments of PG&E's ratepayers at the PPHs in this proceeding was a simple question: why does the Commission always approve utility requests for higher and higher revenue requirements, year after year? PG&E's ratepayers note that they must oftentimes manage their own spending within strict budgets, and ask why PG&E is not required by this Commission to do the same? We address this question separately for the test year and the post-test years.

4.1.11.1. 2017 Test Year

Our response to these ratepayers is in some ways made easier by the 2017 test year revenue requirement increase proposed in the Settlement Agreement: just $88 million, a 1.1% increase. We believe most of PG&E's ratepayers would find the result reasonable, especially since it is considerably lower than PG&E's original and revised requests. Nevertheless, we remain required to ensure that the components of this result meet the requirements of Rule 12.1(d), namely, that it is reasonable in light of the whole record, consistent with law, and in the public interest. This was the purpose of our item-by-item review in the preceding sections of this decision.

Two additional matters regarding PG&E's 2017 revenue requirement arose during the preparation of today's decision. We address each matter below.

First, on January 11, 2017 PG&E issued a news release announcing "new, streamlined management structures and a series of efficiency measures designed to support the company's ability to continue to modernize and invest in the safety of its electric and gas systems while ensuring that its services remain affordable for customers."[128] According to news reports, the measures

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[128] "PG&E Streamlining Management, Implementing Efficiency Measures to Keep Customer Bills Affordable While Investing in the Future" downloaded at https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20170111_pge_streamlining_management_implementing_efficiency_measures_to_keep_customer_bills_affordable_while_investing_in_the_future.

announced by PG&E are intended to reduce costs by approximately $300 million annually.[129]

As we have discussed in this decision, the Settlement Agreement submitted in August 2016 provided for a total 2017 revenue requirement of $8.004 billion for PG&E's gas distribution, electric distribution and electric generation lines of business, along with supporting lines of business such as Customer Care, Human Resources, Shared Services, Information Technology and overall Administrative and General expenses.[130] We have explained herein that the Commission's primary concern regarding this Settlement Agreement is whether it results in the 2017 GRC revenue requirement that is necessary in order for PG&E to provide safe and reliable service at just and reasonable rates, as required by Pub. Util. Code § 451.[131] In other words, approval of the Settlement Agreement indicates that the Commission is authorizing PG&E to spend $8.004 billion in 2017 for those purposes, because that is the amount supported by the record in this proceeding—no more, but also no less, unless PG&E provides a report to the Commission explaining the reasons for any reduction or redirection of its authorized spending.

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129 "PG&E to Lay Off Employees and Executives as It Tightens Its Belt" http://www.sfgate.com/business/article/PG-E-to-lay-off-390-employees-as-it-tightens-its-10850562.php.

130 Settlement Agreement, Appendix A at 1, line 32.

131 Pub. Util. Code § 451 reads, in pertinent part, "All charges demanded or received by any public utility, or by any two or more public utilities, for any product or commodity furnished or to be furnished or any service rendered or to be rendered shall be just and reasonable … Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities … as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."

With respect to PG&E's January 11th announcement, it is not clear how much of PG&E's intended spending reductions are in budget categories that are funded by its GRC-related revenue requirement. However, assuming for the purpose of this discussion that all of the reductions are in categories that are GRC-funded, PG&E's announcement raises the question of whether PG&E's intention to reduce 2017 spending by $300 million is based on a starting point of $8.004 billion, or some other amount:

- If PG&E intends to spend $300 million less than $8.004 billion after the Commission determines that $8.004 billion is the proper amount pursuant to Pub. Util. Code § 451, that would be contrary to the Commission's direction.
- On the other hand, if PG&E intends to reduce spending by $300 million in order to limit 2017 GRC-related spending to no more than $8.004 billion, that is appropriate.

The timing of PG&E's announcement also creates uncertainty when compared to the timing of PG&E's request in this rate case, because that request has changed over time (such changes are typical during a GRC proceeding). The table below summarizes PG&E's requests.

Revisions to PG&E's Requested Revenue Requirement

		Proposed 2017 Budget	Increase Over Adopted 2016 Revenue Requirement
1	**PG&E Initial Application (September 1, 2015)**	$8.373 billion	$457 million
2	**PG&E Update in Rebuttal Testimony (May 27, 2016)**	$8.235 billion	$319 million
3	**Proposed Settlement (August 3, 2016)**	$8.004 billion	$88 million

It should be noted that the 2017 budget proposed in the Settlement Agreement reflects a reduction of $369 million from the amount PG&E initially requested in this proceeding ($8.373 billion minus $8.004 billion) and a reduction of $231 million from the updated amount PG&E requested as of May 27, 2016 ($8.235 billion minus $8.004 billion). However, neither reduction appears to be entirely "expenses," as shown in the table below.[132] Without more information, it is not possible for the Commission to know the extent to which either reduction overlaps with PG&E's newly announced $300 million reductions.

Summary of PG&E's 2017 GRC Settlement Agreement
($ millions)

	Description	Original (A)	Update (B)	Settlement (C)	Settlement minus Original (C)-(A)	Settlement minus Update (C)-(B)
1	Operation and Maintenance	1,833	1,825	1,794	(39)	(31)
2	Customer Services	367	361	334	(33)	(27)
3	Administrative & General	978	974	912	(66)	(62)
4	Less: Revenue Credits (OORs & Wheeling)	(140)	(140)	(152)	(12)	(12)
5	FF&U, Other Adjs, Taxes Other than Income	185	184	170	(15)	(14)
6	Return, Taxes, Depreciation, and Amortization	5,150	5,030	4,946	(204)	(84)
7	Total Reductions	8,373	8,234	8,004	(369)	(230)

Examined differently, the table below provides PG&E's summary of the reductions made in the Settlement Agreement as compared to PG&E's May 2016 updated 2017 request. A number of these line items do not appear to be expenses, so the Commission cannot determine the relationship between these reductions and the $300 million reduction announced by PG&E on January 11, 2017.

[132] Exhibit PG&E-38, "Summary of PG&E's 2017 GRC Settlement Agreement," slide 8.

Categorization of Reductions in PG&E's 2017 GRC Settlement Agreement
($ millions)

	Item	Reduction	"Expense"?
1	GRC expense reductions	$75 million	YES
2	Changes in depreciation rates	$67 million	Deferred for later collection in rates
3	Short-term Incentive Program and other companywide expense reductions	$50 million	Partial
4	Capital-related reductions and income taxes	$17 million	NO
5	Other operating revenue	$12 million	NO
6	Customer deposits, franchise fees and uncollectibles	$9 million	NO
7	**Total Reduction (with rounding)**	**$231 million**	

Finally, PG&E's announcement also specified that PG&E plans to reduce its number of company officers in 2017 by 15%, or eight positions. Testimony in this proceeding indicates that the base pay of officers and other executives at PG&E, as well as their pensions and benefits and part of the STIP, is included in PG&E's 2017 GRC revenue requirement.[133] This raises the question of whether PG&E's revenue requirement should be reduced, now, to reflect the elimination of eight officer positions. The Commission should not allow PG&E to collect this no-longer-needed funding from customers, only to spend it for some other unspecified purpose.

[133] Exhibit PG&E-43 at 4.

The record in this proceeding is closed; the proceeding was considered submitted for Commission as of October 31, 2016, when a final late-filed exhibit was received. We would have preferred that PG&E brought this matter to our attention within this proceeding, instead of first announcing it in a press release, but PG&E did not take that course. Our challenge is to protect PG&E's ratepayers from excess bill increases without overly delaying implementation of PG&E's 2017 GRC revenue requirement. As noted above, we have no record in this proceeding to assist us. One possible response by the Commission could be to reduce the $8.004 revenue requirement agreed upon in the Settlement Agreement by $300 million; in other words, we could create a "rebuttable presumption" that PG&E intended to implement the entire $300 million reduction after receiving Commission authorization to collect $8.004 billion in rates. In that instance, the entire $300 million would be collected from ratepayers, PG&E would reduce 2017 spending by $300 million, and the entire $300 million would be used by PG&E solely to augment its authorized rate of return. If this is not the case, it is up to PG&E to demonstrate why it is not. The other parties to the Settlement Agreement, and other parties to this proceeding, should also be provided an opportunity to inform the Commission on this matter.

Our solution to the bind in which PG&E has placed us is to authorize the 2017 revenue requirement that we have determined in this decision to be proper, but require PG&E to submit positive proof that PG&E is not collecting in rates any funds rendered unnecessary by the $300 million in spending reductions that it announced on January 11, 2017. PG&E shall submit this proof as part of its advice letter filing that will be necessary to implement the rate changes authorized by today's decision. PG&E should include a detailed analysis that provides the following information:

1. A mathematical demonstration, with reference to specific line items in PG&E's GRC testimony and/or workpapers in the record of this proceeding, that accounts for the $300 million in 2017 cost reductions announced by PG&E on January 11, 2017. The demonstration should show whether, after accounting for $300 million in reductions, PG&E is still planning to spend $8.004 billion in 2017 on a forecast basis, or some other amount. Copies of the pages cited in the referenced testimony and/or workpapers shall be included as an attachment to the analysis.
2. Separate verification and demonstration, by reference to testimony or workpapers in the record of this proceeding, that the announced reductions in executive positions are accounted for in the GRC forecast for executive compensation that is part of PG&E's forecast $8.004 billion of 2017 GRC-related spending. If the announced reductions are in fact already funded as part of the $8.004 billion forecast, PG&E should provide a revised forecast that removes those costs for 2017. Copies of the pages cited in the referenced testimony and/or workpapers shall be included as an attachment to the analysis.

In the interest of streamlining the Commission's review of this important matter, we stress the necessity for PG&E to provide thorough, dispositive responses to these questions. If the Energy Division rejects PG&E's advice letter because PG&E's "positive proof" is insufficient, the Commission may require PG&E to take remedial action.

The second matter that arose during the preparation of today's decision concerns PG&E's criminal conviction in United States of America v. Pacific Gas and Electric Company.[134]

On August 9, 2016, a federal jury found PG&E guilty on five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act and one count of obstructing a federal agency proceeding. On January 26, 2017, the Court issued a judgment of conviction.[135] The Court sentenced PG&E to a 5-year corporate probation period, oversight by a third-party monitor, a fine of $3 million to be paid to the Federal government, certain advertising requirements, and community service.

In the judgment, the Court specified that "any fines and special assessment payment is not to be passed off to the ratepayers."[136] In a separately entered order concerning the third-party monitor, the Court directed that "PG&E shall pay reasonable compensation and expenses of the Monitor, and any persons hired by the Monitor pursuant to his/her authority hereunder. The Monitor, and any persons hired by the monitor, shall be compensated in accordance with their hourly rates or a reasonable fee determined by the Monitor based on applicable market rates"; however, the Court did not specify whether this compensation

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[134] United States of America v. Pacific Gas and Electric Company, United States District Court, Northern District Of California, San Francisco Division, Case No. CR 14-00175 TEH.

[135] United States of America v. Pacific Gas and Electric Company, United States District Court, Northern District Of California, San Francisco Division, Case No. CR 14-00175 TEH, Judgment in a Criminal Case, January 31, 2017.

[136] Judgment, at 3 of 18.

should not be paid by PG&E's ratepayers, as the Court did specify with respect to the fine imposed on PG&E.

On January 26, 2017 PG&E filed a Form 8-K with the U.S. Securities and Exchange Commission and stated "at December 31, 2016, PG&E Corporation and the Utility's Consolidated Balance Sheets include a $3 million accrual in connection with this matter. The Utility <u>could</u> incur material costs, not recoverable through rates, in the event of non-compliance with the terms of probation <u>and in connection with the monitorship</u> (including but not limited to monitor's compensation or costs resulting from recommendations of the monitor)." [emphasis added.]

The Commission should determine whether or not PG&E intends to seek recovery in rates for the costs that it will incur in connection with the monitorship imposed by the court. Therefore, PG&E shall include in its comments on this proposed decision a statement that explains its proposed ratemaking treatment for the costs that it will incur in connection with the monitorship imposed by the court.

4.1.11.2. 2018-2019 Post-Test Years

Another noteworthy aspect of the Settlement Agreement is that the agreed-upon increases for the post-test years are considerably higher than the agreed-upon $88 million Test Year increase, and only slightly lower than the amounts originally requested by PG&E.

As ORA noted in its testimony, utilities are not automatically entitled to post-test year revenue increases. We include ORA's succinct history of the

Commission's Post-Test Year ratemaking here to provide additional context for our discussion:[137]

> The GRC proceeding is used to periodically review and set reasonable rates for utilities for a specific test year. For the period between GRC proceedings, the Commission has, in some cases, granted attrition-type increases and, in other cases, has not provided such increases. In the past, the Commission has stated:
>
> The attrition mechanism is not an entitlement. Nor is it a method of insulating the company from the economic pressures which all businesses experience…Neither the Constitution nor case law has ever required automatic rate increases between general rate case applications.
>
> Before 1982, a utility's base revenue requirement was generally adjusted only during GRC proceedings. In the period between GRC proceedings, base rates would not change, but the utilities received additional income from customer growth. Post-Test Year, or attrition, rate adjustments were implemented in the early 1980's primarily because of the unprecedented high inflation and lower rates of customer growth and sales experienced by utilities in the late 1970's and early 1980's.
>
> Since the mid-1980's, inflation has generally declined to more modest historical levels. The utilities have also had various forms of revenue balancing account protection from sales fluctuation. Additionally, utility fuel-related costs that had high volatility, and over which utilities have limited control, were removed from base rates and are now recovered through separate mechanisms with balancing accounts.

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137 Exhibit ORA-21 at 4-5. ORA cites its quote from a prior Commission decision as D.93-12-043, 52 CPUC2d 471, 492.

Given the history recounted by ORA, in today's era of low inflation and numerous utility balancing accounts, we would not have been surprised had one or more intervenors recommended that PG&E receive no post-test year increases. Nevertheless, in this proceeding PG&E did request post-test year increases, and neither ORA nor any other party submitted testimony recommending that the Commission deny PG&E's requests entirely. We attribute this to an evolution in parties' approach to the purpose of Post-Test Year revenue requirement increases, as we discuss further below.

It is not immediately evident what was "settled" with respect to 2018 and 2019, if a settlement is defined as a compromise agreement between two disputed amounts. The agreed-upon post-test year revenue requirements are also described as "fixed dollar amounts".[138] Although PG&E included "bottom up" forecasts for 2018 and 2019 in its testimony, intervenors point out that the entire premise of a three-year GRC cycle is that the Test Year revenue requirement will be the focus of the utility showing and of intervenor testimony, because resource constraints prevent intervenors from subjecting every year of a utility's three-year forecast to the same level of detailed analysis that they devote to the test year forecasts. Thus, in this proceeding, ORA and TURN testimony regarding PG&E's post-test year revenue requirement relies on various escalators and other estimation methods so that intervenors do not have to review PG&E's bottom up forecasts for those years. This approach resulted in

[138] As shown in Appendix B to the Settlement Agreement, the 2018 increase shall be $250 million for electric distribution, $110 million for gas distribution, and $84 million for electric generation. The 2019 increase shall be $195 million for electric distribution, $96 million for gas distribution, and $70 million for electric generation.

testimony indicating that (1) PG&E should be provided with increases in its annual Post-Test Year expense budgets, based on reasonable expense escalation factors and, (2) PG&E should also be authorized to budget for "new" capital spending in 2018 and 2019, beyond what was authorized for the 2017 test year, because intervenors agree that PG&E's infrastructure should be replaced or expanded by amounts above PG&E's depreciation expense for those years.[139]

We believe that PG&E's ratepayers would not expect that PG&E's operating expenses and capital spending are subject to close Commission scrutiny in just one year out of every three, with PG&E spending in the other two years entirely according to management discretion. That has never been the intention of this Commission, and in the past two PG&E proceedings the Commission has imposed additional reporting requirements on PG&E by means of the spending accountability reports adopted in D.11-05-018 and continued by D.14-08-032. In these reports, all spending during the GRC period must be reconciled to budgeted amounts, and deviations from those budgets must be explained and justified. Those existing reporting requirements are further strengthened in the Settlement Agreement, as we discuss later in this decision.

In order to ensure better transparency for the Commission's review and decision regarding the settled-upon revenue requirements, the Settlement Workshop and several volumes of late-filed testimony prepared by PG&E

[139] PG&E explains its position that its plant additions in excess of depreciation is the primary driver of the need for attrition revenue requirement increases in Exhbit PG&E-11 at page 1-7 through 1-8.

provided a deeper discussion and illustration of the components of the 2017, 2018 and 2019 revenue requirements.

Regarding the post-test year agreed-upon amounts, the central questions about the post-test years revolved around the likely uses of the agreed-upon lump sum funding, and whether those uses should be approved by the Commission pursuant to Rule 12.1(d). In response, PG&E cited the need for "management discretion" and the difficulty of accurately budgeting, at this time, for the "out years" beyond 2017.

The additional record provided by the Settlement Workshop presentations and transcript, as well as the late-filed exhibits, provided visibility into these revenue requirements that was not completely available from the pre-Settlement record. That record did include PG&E's bottom up forecasts for 2018 and 2019, albeit only in disaggregated form throughout PG&E's testimony and workpapers. For these reasons, PG&E was required to submit late filed exhibits on "Test-year and Post Test-year Revenue Requirement" (Exhibit PG&E-41) and "Calculation of Imputed Regulatory Values for the Post Test-Years" (Exhibit PG&E-46).

In preparing its "imputed regulatory values" to support the Settlement Agreement, PG&E first separated the agreed-upon revenue requirements for 2018 and 2019 into expense and capital:

	2018	2019
Expense-related	$86	$83
Capital-related	$358	$278
GRC Total	**$444**	**$361**

Next, these annual totals were separated into PG&E's three functional areas: gas distribution, electric distribution, and electric generation, with those sub-totals matching the allocations established in Appendix B of the Settlement Agreement. Finally, each subtotal was allocated to expense or capital-related revenue requirements using an "imputation" method. The results are shown below:

Line No.		2018	2019
1	Gas Distribution		
2	Expense	($41)	($17)
3	Capital-Related	$151	$113
4	Subtotal Gas Distribution	$110	$96
5	Electric Distribution		
6	Expense	$68	$56
7	Capital-Related	$182	$139
8	Subtotal Electric Distribution	$250	$195
9	Electric Generation		
10	Expense	$58	$44
11	Capital-Related	$26	$26
12	Subtotal Electric Generation	$84	$70
13	GRC Total		
14	Expense	$86	$83
15	Capital-Related	$358	$278
16	**GRC Total**	**$444**	**$361**

In hindsight, we note that in Exhibit PG&E-46 PG&E did not provide actual budgets for 2018 and 2019; rather, as agreed to by the ALJ at PG&E's suggestion, it provided what it describes as "imputed regulatory values" that are derived by various calculation methodologies.[140] According to PG&E, those

[140] Exhibit PG&E-46 at 1-5.

budgets have not yet been prepared. Unfortunately, we find that PG&E's method of imputing values does not provide a sufficiently clear picture of what we can expect PG&E to spend in those years, so it is of only partial value to us in evaluating the merits of the agreed-upon Post-Test Year increases. Thus, in order to evaluate the merits of those amounts, we are left to compare the near- "black box" Settlement Agreement for 2018 and 2019 with PG&E's bottom up forecasts for those years, provided in PG&E's original showing.

Our interest here is in verifying that PG&E went to the effort of preparing those forecasts when it developed its GRC application, not in holding PG&E to those exact budgets in 2018 and 2019. On the contrary, we adopt reporting requirements elsewhere in this decision that ensure that PG&E's evolving spending plans for 2018 and 2019 will be the subject of an ongoing dialog between the utility and this Commission and its staff, because we believe that this is what PG&E's customers expect of us. Thus, here we simply provide one example of PG&E's bottom up forecasts to demonstrate that PG&E has, in fact, provided detailed forecasts of its spending in 2018 and 2019. These budgets are available for the Commission and the parties in this proceeding to examine if they wish to do so.

The example below is taken from PG&E's September 1, 2015 testimony and workpapers regarding electric distribution capital expenses.

1. PG&E forecast increases in its electric distribution revenue requirements of $164 million, $276 million, and $188 million for 2017, 2018 and 2019, respectively.[141]

[141] PG&E Application at 2-3.

2. Of those amounts, the underlying electric distribution capital budgets equaled $1.819 billion, $1.817 billion, and $1.884 billion, respectively.[142]

3. Within those capital budgets, one "program areas" is "Customer Connection, Demand Growth and Franchise Obligation" with annual 2017-2019 budgets of $813 million, $848 million, and $878 million.[143] Thus, growth from 2017 to 2018 equaled $35 million, and growth from 2018 to 2019 equaled $30 million.[144]

4. Within that program area, one of the specific line items is "Electric Distribution Substation Capacity", identified by PG&E as Major Work Category (MWC) 46. The 2017-2019 forecast revenue requirements for MWC 46 are $85 million, $98 million, and $100 million, respectively.[145]

5. Within MWC 46, the individual line item amounts that sum to these annual revenue requirements are provided on PG&E's workpaper WP 13-13:

    a. Normal Capacity Def. (Excludes New Business Related)

    b. Circuits with Large Numbers of Customers

    c. Substation Transformer Emergency Capacity

    d. Emergent Work Program New Business Related

    e. Unidentified Emergent Work

    f. Escalation - MWC 46

    g. 46B – Cornerstone

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142 Exhibit PG&E-4, WP 1A-5.

143 Exhibit PG&E-4, WP 1A-5.

144 Exhibit PG&E-4, WP 1A-7 and WP 1A-8.

145 Exhibit PG&E-4, WP 1A-9.

   h. 46V - SmartGrid VVO (Volt/VAR Optimization)
   i. 46W - DER Integration Capacity
   j. Escalation - MWC 46 (VVO and DER Integration Capacity)

6. Choosing one line item from the list above, item (h), the 2017-2019 forecasts for "SmartGrid VVO (Volt/VAR Optimization)" are $2.175 million, $8.569 million, and $8.106 million, respectively. PG&E provides a workpaper showing those values, with footnotes describing "assumptions and details."[146]

Our purpose in itemizing one example of PG&E's support for its electric distribution capital spending forecast for 2017, 2018 and 2019 is to illustrate that PG&E itemizes the values that make up a forecast totaling $1.8 billion, all the way down to the level of just several millions of dollars. Although this level of detail is provided in PG&E's testimony and workpapers, PG&E and the other Settling Parties ask us to approve revenue requirements based on only their close scrutiny and negotiation over 2017 budgets, without the same detailed review by intervenors of PG&E's 2018 and 2019 forecasts. We are comfortable with the former, but not entirely comfortable with the latter. However, based on our own examination of PG&E's "bottom up" forecasts for 2018 and 2019, we find the agreed-upon post-test year revenue requirements in the Settlement Agreement to

[146] Exhibit PG&E-4, WP 13-38.

be reasonable and conclude that we should adopt the lump sum agreed-upon increases for those years.[147]

Later in this decision, we also approve provisions of the Settlement Agreement that will further strengthen our existing budget accountability reporting provisions and enable us to further improve the transparency around PG&E's forecast and recorded spending in those post-test years.

4.2. Non-Financial Provisions of the Settlement (Section 3.2)

Section 3.2 of the Settlement Agreement presents and resolves numerous non-revenue requirement-specific issues. Settling Parties assert that settlement of the issues set forth in Section 3.2 reflects a reasonable compromise of the positions taken by the parties, many of which are reflected in Chapter 2 of the JCE. Furthermore, given the various parties' recommendations in this area, Settling Parties suggest that these provisions are supported by the record and, in light of the various compromises set forth in this Agreement, these provisions are reasonable and in the public interest.

This Section of the Settlement Agreement is organized according to PG&E's lines of business, so we review the agreed-upon outcomes in that order as well.

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[147] We note that on February 7, 2017 a number of parties, including PG&E, filed a Joint Petition for Modification of D.12-12-034 and D.13-03-015, in the Commission's Cost of Capital proceeding. In the event that the Commission approves a cost of capital for PG&E in that proceeding that differs from the value in effect today, unless otherwise directed by Commission decision PG&E must incorporate its new cost of capital in the advice filing it makes to implement the 2018 and 2019 post-test year revenue requirements that we adopt today.

4.2.1. Gas Distribution (Section 3.2.1)

4.2.1.1. Gas Leak Management (Section 3.2.1.1)

PG&E states that its simple goal is to find and fix natural gas leaks on its natural gas distribution system as quickly as possible.[148] Chapter 6C of Exhibit PG&E-3 provides PG&E's initial 2017 forecast associated with its Leak Management programs, including Leak Survey, Leak Repair, pipe replacement due to emergencies, and replacement of leaking service lines. PG&E asserts that its requested revenue requirement would enable PG&E to find and fix leaks on its distribution system more quickly.[149]

Earlier in this decision we approved the agreed-upon reduction of $2.5 million for leak management activities as part of a total $18 million reduction to PG&E's total forecast 2017 gas distribution revenue requirement. Settling Parties also agreed to a number on non-financial changes to the structure of PG&E's gas leak management program, which we discuss here.

In its testimony, PG&E forecast performing leak surveys on a four-year cycle. ORA and TURN recommended that the Commission fund a five-year leak survey cycle. EDF and CUE recommended that the Commission fund and require PG&E to perform a three-year leak survey. CUE also recommended that PG&E be required and funded to perform an annual leak survey of Aldyl-A pipe, and EDF recommended additional monitoring of certain vintage pipe. EDF also recommended that the Commission authorize sufficient funds for PG&E to

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[148] Exhibit PG&E-3, Chapter 6C at 6C-7.

[149] *Id*. at 6C-1.

implement the emissions reduction measures currently under consideration in R.15-01-008 related to SB 1371.[150]

Settling Parties assert that Section 3.2.1.1 of the Settlement Agreement adopts a reasonable compromise of these litigation positions. First, it recognizes that the settled-upon revenue requirement is sufficient for PG&E to perform leak surveys on a four-year cycle, and provides that PG&E will commence a four-year cycle starting in 2017. Second, to increase transparency and facilitate emissions reductions, it also requires PG&E to do the following:

1. Collect leak survey and leak find rate data by Maintenance Activity Type differentiated by leak grade;
2. Perform analysis on the likelihood of Grade 3 leaks becoming more hazardous over time;
3. Provide information on open leaks on a publicly accessible web site;
4. Keep the number of open above-ground Grade 3 leaks at a minimum;
5. Reduce the number of open below-ground Grade 3 leaks, as authorized funding allows; and
6. Continue to work collaboratively with EDF and CUE to evaluate technologies that may be implemented for stationary leak monitoring at certain facilities.

[150] SB 1371 (Statutes 2014, Chapter 525) requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities. On January 15, 2015 the Commission opened R.15-01-008 to carry out the intent of SB 1371 ("Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leakage Consistent With Senate Bill 1371").

4.2.1.2. Idle Gas Stubs (Section 3.2.1.2)

In its testimony, PG&E explains that gas service "stubs" are created in two ways: (1) the stub was installed as part of an anticipated new business development that was never completed; or (2) the service was cut off at a point on the service line, not at the main, and was never reconnected. "Idle services" are defined as services that no longer provide gas to customers. PG&E states that the primary risk with stubs or idle services is exposure to dig-ins or external forces. For these reasons, PG&E maintains a "Stubs Program" that supports the removal of gas service stubs that do not have a future use, and gas services that are idle and are required to be cut off.[151]

Section 3.2.1.2 of the Settlement Agreement adopts PG&E's proposed policy concerning the removal of idle gas stubs. Settling Parties state that no party opposed PG&E's proposed policy change regarding the removal of idle gas stubs. Under the new policy, a newly created stub would be assessed for reuse at the time the cut-off is requested. If the stub is determined to be unsuitable for reuse, the entire service would be cut-off at the connection to the distribution main. Settling Parties state that the new policy will result in creation of fewer new stubs and limit the re-use of existing stubs, and that the new policy will improve efficiency and safety by, among other things, reducing the risk of dig-ins.

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[151] Exhibit PG&E-3, Chapter 4 at 4-25 to 4-26.

4.2.1.3. Gas Distribution Pipeline Replacement Program (Section 3.2.1.3)

In Chapter 4 of Exhibit PG&E-3, PG&E explains that it established its Gas Distribution Pipeline Replacement Program (GPRP) in 1985 and that the scope of the program focuses on replacement of cast iron and pre-1940 steel pipe. This program has enabled PG&E to systematically deactivate all cast iron (over 830 miles of pipe) over the past 30 years.[152]

Section 3.2.1.3 of the Settlement Agreement focuses on the reporting requirements around the GPRP, and within that topic, PG&E's Cross Bore Program. PG&E explains that a cross bore is "the inadvertent placement of a gas main or service through a sewer line. Cross bores occur during trenchless construction resulting in the gas pipe being installed through a waste water or storm drain system. Cross bores pose a risk as they can result in a gas leak into the sewer system if damaged during mechanical sewer cleaning operations."[153] PG&E states that cross bores are an issue of increasing concern for gas utility operators nation-wide and are identified as a high risk to public and employee safety.[154]

In response to PG&E's forecasts for the Cross Bore Program, ORA recommended that PG&E be directed to submit annual reports to the Commission which track forecast as compared to actual cross bore work, and to explain any variances. In its rebuttal testimony, PG&E opposed ORA's

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[152] *Id.* at 4-22.

[153] *Id.* at 4-15.

[154] *Ibid.*

recommendation on the grounds that PG&E provides sufficiently detailed information to the Commission through its semi-annual Gas Distribution Pipeline Safety and Budget Compliance reports.

Section 3.2.1.3 of the Settlement Agreement adopts ORA's proposal, such that PG&E shall report on its Cross Bore Program within its GPRP Program annual report. PG&E will track forecast and actual values for number of inspections, number of repairs, and expenses, and explain variances between forecast and actual.

4.2.1.4. Gas Distribution Pipeline Safety Reports (Section 3.2.1.4)

In its decision on PG&E's 2011 GRC, the Commission determined that due to the Commission's responsibilities and concerns regarding gas pipeline safety, additional reporting requirements related to gas distribution pipelines should be imposed on PG&E. The Commission required PG&E to submit semi-annual Gas Distribution Pipeline Safety Reports (GDPSR) to the Directors of the Commission's Consumer Protection and Safety Division (now Safety and Enforcement Division) and Energy Division.[155]

According to Settling Parties, in response to requests made by Settling Parties during settlement negotiations, PG&E agreed to various enhancements to the GDPSR required by D.11-05-018. The additional enhancements are described in Section 3.2.1.4 of the Settlement Agreement. In the enhanced reports, PG&E shall report on units of work authorized and performed at the MAT level, as

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155 D.11-05-018, Conclusion of Law 6, Ordering Paragraph 44. The requirements of the reports are detailed in Attachment 5 to D.11-05-018.

applicable. PG&E shall also provide an explanation of the reasons for not performing work specified in a GRC decision.

Section 3.2.1.4 also provides that the frequency of these reports should be changed from semiannual reports to annual reports. Nonetheless, this Section also explicitly provides that the Commission may retain the current semiannual reporting frequency. Settling Parties state that this provision is provided so as to allow the Commission to retain the current reporting frequency without modifying the Settlement Agreement and triggering the Settling Parties' rights under Rule 12.4(c).

4.2.1.5. Discussion of Gas Distribution Non-Financial Items

Based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement, we find that the agreed-upon changes to PG&E's practices and reporting requirements regarding its Gas Distribution LOB are reasonable and we conclude that they should be adopted.

4.2.2. Electric Distribution (Section 3.2.2)

4.2.2.1. Reliability Reporting (Section 3.2.2.1)

In response to PG&E's Reliability Program forecast, CFC recommended that PG&E provide data showing that PG&E was narrowing the reliability gap between worst-performing divisions.[156] In rebuttal, PG&E noted that many

[156] Exhibit CFC-2--Electric Distribution Reliability Upgrades at 7.

factors contributing to reliability are outside of PG&E's control.[157] No other party submitted testimony on this issue.

Section 3.2.2.1 of the Settlement Agreement provides that PG&E will report in its next GRC the ratio of the averaged Customer Average Interruption Duration Index statistics for the five worst performing divisions against the average for the five best performing divisions.

Separately, no party opposed PG&E's proposal to consolidate reliability reports, which will result in administrative efficiency.[158] Section 3.2.2.1 of the Settlement Agreement therefore also adopts PG&E's proposal to consolidate reliability reports.[159]

4.2.2.2. Annual Reporting (Section 3.2.2.2)

In several sections of the financial provisions of the Settlement Agreement, Settling Parties agreed to various modifications to PG&E's forecasts of asset replacements, across various asset categories. In addition, Settling Parties agreed to reporting requirements relating to some of these assets. Section 3.2.2.2 of the Settlement Agreement requires PG&E to report annually on work conducted on certain poles, circuit breakers, cable, overhead conductor, switches, FLISR installations and fuses. This reporting will be provided as part of the modified Spending Accountability Reports agreed to in Section 3.2.8.3 of the Settlement Agreement.

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[157] Exhibit PG&E-23 V1 at 9-22 to 9-23.

[158] Exhibit PG&E-4 at 9-31.

[159] As PG&E noted in its rebuttal testimony (Exhibit PG&E-23 V1 at 9-23), after PG&E included this proposal in its opening testimony, the Commission approved the consolidation of these reports in D.16-01-008.

4.2.2.3. Surge Arrester Progress Report (Section 3.2.2.3)

In testimony, PG&E explains that the Surge Arrestor Grounding program is a new maintenance program for which PG&E seeks funding in this GRC:[160]

> Surge arrestors, also known as lightning arrestors, lessen the risk of PG&E equipment failure and consequent customer property damage due to overvoltage events such as lightning strikes. Surge arrestors are connected to earth via a ground wire and ground rods.
>
> Between 1974 and 2008, when surge arrestors were installed in the same location as distribution transformers, PG&E often used a shared ground wire and ground rods to ground both the surge arrestors and the transformers. PG&E has determined that this "common ground" poses a safety risk and does not comply with current regulatory guidance. Under the Surge Arrestor Grounding program, PG&E will install separate ground wires and ground rods for the surge arrestors in these "common ground" locations.

In its testimony, TURN recommended a one-way balancing account in response to PG&E's forecast for its surge arrester program, to address TURN's concerns regarding PG&E's unit forecast.[161] In rebuttal, PG&E opposed TURN's proposed balancing account but stated it was willing to include information in an annual report to address TURN's concerns.[162] ORA recommended no reductions to the program, but did recommend reporting requirements that

[160] Exhibit PG&E-4, Chapter 6 at 6-35.

[161] Exhibit TURN-3 at 17.

[162] Exhibit PG&E-23, V1 at 6-19.

PG&E agreed were reasonable.[163] No other party presented recommendations regarding the surge arrester program.

Section 3.2.2.3 of the Settlement Agreement adopts ORA's and TURN's recommendations that PG&E report annually on the progress of work in the Surge Arrester Grounding Program. This reporting will be provided as part of the modified Spending Accountability Reports agreed to in Section 3.2.8.3 of the Settlement Agreement, and will include the provision of the following information:

1. The units completed in the Surge Arrester Grounding program in the previous year;
2. The total amount of customer spend in the Surge Arrester Grounding program in the previous year; and
3. A count of locations mistakenly identified in PG&E's location survey.

4.2.2.4. Pole Loading (Section 3.2.2.4)

In response to PG&E's pole replacement forecast, CUE recommended that PG&E initiate a pole loading analysis program.[164] In rebuttal, PG&E agreed that such a program would be reasonable.[165] Section 3.2.2.4 of the Settlement Agreement provides that PG&E shall develop, on an accelerated basis, a program to identify overloaded poles that do not meet current loading standards. Furthermore, PG&E shall prioritize replacing overloaded poles in high-risk areas, starting with wildfire areas.

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163 Exhibit ORA-9 at 26.

164 Exhibit CUE-1 at 35.

165 Exhibit PG&E-23, V1 at 8-2.

4.2.2.5. Overhead Conductor Study (Section 3.2.2.5)

In response to PG&E's Reliability Program forecasts, CUE recommended that PG&E perform an overhead conductor study to learn its true distribution of service life, the near-term replacement rate and long-term steady-state replacement rate.[166] In rebuttal, PG&E objected to such a study as unnecessary on the grounds that PG&E had completed infrared inspections on 50 % of the total overhead system and because PG&E's implementation of its System Tool for Asset Risk would provide pertinent information in this area.[167] No other party submitted testimony on this issue.

Section 3.2.2.5 of the Settlement Agreement requires PG&E to perform a study on its overhead conductor and to use this study to inform PG&E's next GRC application.

4.2.2.6. Facilities Charge (Section 3.2.2.6)

No party opposed PG&E's proposal to continue the facilities charge methodology for the light-emitting diode Streetlight Conversion Program approved in the 2014 GRC decision, and to review whether the current facilities charge needs to be adjusted as part of Phase 2 of this GRC. Section 3.2.2.6 of the Settlement Agreement adopts PG&E's proposal to continue the facilities charge.

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166 Exhibit CUE-8-Errata to Prepared Testimony of David Marcus at 26.

167 Exhibit PG&E-23, V1 at 9-20.

4.2.2.7. Line Extension Reporting Requirements (Section 3.2.2.7)

In its testimony, PG&E proposed that the annual line extension report required under PG&E's 2003 GRC Decision be discontinued on the grounds that production of the report is burdensome and PG&E receives very limited feedback or questions in response.[168] TURN recommended that a portion of the report be submitted with workpapers for the base year in future GRCs.

Section 3.2.2.7 of the Settlement Agreement allows PG&E to discontinue the production of the annual Line Extension Reporting report mandated in PG&E's 2003 GRC. Instead, PG&E shall include in future GRCs certain information that was historically provided in the earlier report. Specifically, PG&E shall in future GRCs include in its workpapers for the GRC base year the line extension data and information in rows 1-14 of Attachment A of the earlier report, as well as the material included in Attachment B of the earlier report.

4.2.2.8. Rule 20A Work Credit Allocation (Section 3.2.2.8)

Section 3.2.2.8 of the Settlement Agreement adopts PG&E's proposal that the Commission continue the annual Rule 20A work credit allocation amount of $41.3 million through the term of the 2017 GRC, in order to continue to reduce the number of accumulated allocations.

We addressed Section 3.2.2.8 of the Settlement Agreement earlier in this decision, as part of our resolution of budgetary issues regarding PG&E's Rule 20A program.

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[168] Exhibit PG&E-4, Chapter 17 at 17-37.

4.2.2.9. Discussion of Electric Distribution Non-financial Items

With one exception regarding PG&E's Rule 20A program, discussed earlier in this decision, based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement, we find that the agreed-upon changes to PG&E's practices and reporting requirements regarding its Electric Distribution LOB are reasonable and we conclude that they should be adopted.

4.2.3. Energy Supply (Section 3.2.3)

4.2.3.1. Diablo Canyon Power Plant (Section 3.2.3.1)

A4NR and TURN raised a number of issues in their testimony related to license renewal of Diablo Canyon that have been addressed by PG&E's June 21, 2016 announcement that it has entered into a Joint Proposal under which it would seek Commission approval to retire Diablo Canyon at the end of its current Nuclear Regulatory Commission (NRC) operating licenses in 2024 (Unit 1) and 2025 (Unit 2) and replace Diablo Canyon's energy with a portfolio of energy efficiency and greenhouse gas-free energy resources. While the Joint Proposal requires Commission approval and will be filed in a separate application at the Commission, PG&E's decision under the Joint Proposal not to seek license renewal for Diablo Canyon resolves a number of issues raised by TURN and A4NR as set forth in Section 3.2.3.1 of the Settlement Agreement.

First, A4NR recommended that the depreciation schedule for Diablo Canyon, which currently assumes that the plant will cease operations when its NRC operating license expires, should be extended assuming that Diablo

Canyon will operate into 2044. In Section 3.2.3.1.1 of the Settlement Agreement, A4NR withdraws its proposed revision to the depreciation schedule based on the assumption that the Joint Proposal will be approved by the Commission and Diablo Canyon will be retired consistent with the depreciation schedule proposed by PG&E in the GRC. A4NR reserves all rights if the Joint Proposal is rejected and PG&E elects to proceed with license renewal.

A second issue in contention was the treatment of the Unit 2 main generator stator project, a capital project in PG&E's 2017 GRC with a forecasted in-service date in 2019. A4NR and TURN both recommended that the forecasted costs for this capital project should not be pre-approved for the primary reason that the project may not be needed if PG&E does not proceed with license renewal. Both TURN and A4NR recommended that if PG&E decides to pursue the project, it should be subject to prudence review in the next GRC. In the Settlement Agreement, PG&E stipulates to the withdrawal of its request for pre-approval of the Unit 2 generator stator replacement project.[169] Should PG&E proceed with the project, PG&E has agreed that the decision to proceed with the project and associated project costs will be subject to review as part of PG&E's next GRC application and that the parties reserve all rights to contest PG&E's decision to proceed with the project.[170]

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[169] The project's costs remain in PG&E's capital spending forecast but since the project's in-service date is forecast to be in 2019, the project has no impact on the revenue requirement that would be approved in the Settlement Agreement.

[170] Settlement Agreement, Section 3.2.3.1.2.

Third, A4NR proposed that the costs of PG&E's Independent Spent Fuel Storage Installation expansion project should be removed from rate base to address A4NR's allegation that PG&E has failed to adequately address California Energy Commission (CEC) recommendations on options for expediting the transfer of spent nuclear fuel assemblies to dry cask storage. In the Settlement Agreement, A4NR stipulates to the withdrawal of this recommendation, provided that PG&E conducts a study for expedited transfer of spent fuel assemblies as part of its Diablo Canyon site-specific decommissioning study, as called for in the Joint Proposal. A4NR reserves the right to contest recovery of costs related to spent fuel handling and storage if PG&E fails to conduct the studies called for in the Joint Proposal and coordinate with the CEC.

Fourth, both TURN and A4NR recommended that PG&E be required to submit information annually to the Commission related to PG&E's decision-making on license renewal. TURN proposed that PG&E provide a cost-effectiveness showing in the next GRC and A4NR proposed that PG&E file annual advice letters addressing the status of license renewal and providing certain analysis. Since PG&E has decided in the Joint Proposal not to proceed with license renewal, TURN and A4NR agreed no longer to pursue these requests. However, in the Settlement Agreement, PG&E has agreed to submit Tier 1 advice letters notifying the Commission of any material changes to the condition of Diablo Canyon that may affect the retirement date. In addition, PG&E will on an annual basis update its GRC forecast of planned capital improvements, projects and additions for Diablo Canyon as part of its proposal for implementation of the Joint Proposal.

Fifth, A4NR has agreed to withdraw its proposal that the ratemaking for Diablo Canyon should be modified to a performance-based methodology.

4.2.3.2. Department of Energy Refund Credit (Section 3.2.3.2)

In Chapter 3 of Exhibit PG&E-5, PG&E explains that in September 2012, PG&E entered into a settlement agreement with the U.S. Department of Energy (DOE) to resolve litigation surrounding DOE's failure to perform under spent fuel disposal agreements for Diablo Canyon Power Plant (DCPP) and Humboldt Bay Power Plant (HBPP). In the 2014 GRC proceeding, PG&E reached a joint proposal with TURN and Marin Energy Authority (now Marin Clean Energy) for crediting the proceeds of the DOE litigation settlement to generation rates (for reimbursement of spent fuel related storage costs for DCPP) and to nuclear decommissioning rates (for reimbursement of spent fuel related storage costs for HBPP). PG&E proposes to use the same mechanism in the 2017-2019 GRC period, whereby 72% of the proceeds will be allocated to the Utility Generation Balancing Account, to the benefit of ratepayers; the remaining 28% will be credited to the Nuclear Decommissioning Adjustment Mechanism, which is a separate surcharge on customer bills.

No party opposed PG&E's proposal to continue the mechanism to credit the DOE refunds to the generation revenue requirement. Section 3.2.3.2 of the Settlement Agreement adopts PG&E's proposal.

4.2.3.3. Levelization of Costs (Section 3.2.3.3)

In its opening testimony, PG&E made two proposal regarding "levelization" of cost recovery related to large and "lumpy" expenses that would otherwise have relatively significant one-time impacts on customer rates.

First, PG&E noted that in 2019, Diablo Canyon will have two refueling outages instead of the typical one per year. In order to smooth out the impacts to customers, PG&E proposes to spread the costs of the second refueling outage over the three-year GRC period, such that one third of the costs would be recovered in 2017, 2018 and 2019. This is the same treatment of the second refueling outage that was adopted in the 2014 GRC.[171]

Second, PG&E also proposes to levelize the costs associated with the major Long-Term Service Agreements outages at its Gateway and Colusa generating stations. PG&E explains that these major outages also occur every few years (based on run rates and stops/starts) and result in "lumpy" costs. PG&E proposes to smooth out the costs by amortizing them over the 2017-2019 period.[172]

No party opposed PG&E's proposal to levelize the costs of the second refueling outage at Diablo Canyon and the Long Term Service Agreements at Colusa and Gateway Generating Stations. Section 3.2.3.3 of the Settlement Agreement adopts PG&E's proposal.

This section also adopts PG&E's proposal to true up in its next GRC any accelerated milestone payments due to the need to call on Colusa and Gateway Generating Stations more frequently. Settling Parties explain that this need arises from the increasingly complex challenge of balancing the system to address intermittent renewable resources. No party opposed PG&E's proposal.

4.2.3.4. Photovoltaic Program Issues (Section 3.2.3.4)

No party opposed PG&E's proposal that the ongoing revenue requirement associated with PG&E's Photovoltaic (PV) Program assets should be included in

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171 Exhibit PG&E-5, Chapter 8 at 8-10.

172 *Ibid*; Exhibit PG&E-5, Chapter 5 at 5-41.

the generation revenue requirement for the term of this rate case and the capital cost savings relating to the PV Program should continue to be credited to the Utility Generation Balancing Account. Section 3.2.3.4 of the Settlement Agreement adopts PG&E's proposal.

4.2.3.5. Discussion of Electric Generation Non-financial Items

We find that the agreed-upon changes to PG&E's practices regarding its Electric Generation LOB are reasonable and we conclude that they should be adopted. Our findings and conclusions are based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement.

4.2.4. Customer Care (Section 3.2.4)

4.2.4.1. Community Choice Aggregator Services and Fees (Section 3.2.4.1)

In D.13-04-020, the Commission approved a settlement agreement regarding Direct Access (DA) and Community Choice Aggregator (CCA) service fees. The settlement included agreement that PG&E would propose new DA and CCA service fees in Phase 2 of its 2017 GRC.[173] As noted above, in this Phase 1 GRC application, PG&E forecast costs for enhanced customer billing and Contact

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[173] D.13-04-020, "Decision Approving Settlement Agreement Regarding Direct Access and Community Choice Aggregation Service Fees and Approving Disposition of the Direct Access Discretionary Cost/Revenue Memorandum Account," Ordering Paragraph 4.

Center support to accommodate increasing third-party billing based on the growth of CCA programs.[174]

Section 3.2.4.1 of the Settlement Agreement provides that in recognition of the connection between possible GRC Phase 1 investments and the services provided, and fees charged to Community Choice Aggregators, MCE and PG&E will meet at least six months prior to the filing of PG&E's next GRC Phase 1 to discuss possible investments and their connection to CCA services and fees.

4.2.4.2. Future Consultation on Customer Retention (Section 3.2.4.2)

As addressed earlier in this decision, Section 3.1.5 of the Settlement Agreement provides for a revenue requirement reduction of $807,000 associated with customer retention activities in MWC FK, and that during the term of the 2017 GRC, PG&E will record those customer retention costs below-the-line.

In a related provision, Section 3.2.4.2 of the Settlement Agreement provides that at least six months prior to filing the next GRC, PG&E shall contact the Merced, Modesto and South San Joaquin Irrigation Districts, as well as MCE, in order to inform these entities whether PG&E intends to seek ratepayer funding for such customer retention activities in the case.

4.2.4.3. Customer Service Offices (Section 3.2.4.3)

PG&E proposed closure of up to 26 of its customer service offices in this GRC. ORA, TURN and CUE opposed the proposal. Section 3.2.4.3 of the Settlement Agreement provides that PG&E's request is withdrawn without

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[174] Exhibit (PG&E-6), at 1-3, lines 9-11.

prejudice. The Section also provides that, no earlier than July 1, 2018, PG&E may file an application seeking to close any of its customer service offices. Prior to filing any such application, PG&E shall engage with the IBEW 1245 to discuss impacted employees.

4.2.4.4. Telephone Service Level (Section 3.2.4.4)

PG&E proposed that the Commission reduce PG&E's Telephone Service Level from 80/20 (answering 80 % of calls within 20 seconds) to 76/60 based on evidence that due to the increase in self-service options, the Service Level Mandate is less critical than it was when established approximately 20 years ago. In testimony, PG&E states that the proposed new mandate is consistent with the standard that applies to the Sempra Utilities.[175]

No party opposes the proposal. PG&E estimated that if adopted, the proposed reduction to the Service Level Mandate would result in a $2 million annual cost savings.[176] While TURN did not oppose PG&E's proposal to modify telephone service levels, it argued that a $2.4 million reduction to PG&E's forecast would be appropriate, as opposed to the $2 million reduction PG&E had forecast.[177] As discussed above, Section 3.1.5 of the Settlement Agreement provides for an overall reduction of $3.8 million to Call Center Operations expense for 2017. This reduction anticipates the cost savings attributable to the

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175 Exhibit PG&E-6, Chapter 4 at 4-15.

176 *Ibid.*

177 Exhibit TURN-8 at 22-23.

Commission's adoption of PG&E's proposal here to reduce its Service Level Mandate.

Section 3.2.4.4 of the Settlement Agreement adopts PG&E's proposal.

4.2.4.5. Small Business Utility Advocates Memorandum of Understanding (Section 3.2.4.5)

PG&E and SBUA state that they have worked collaboratively since the 2014 GRC to identify opportunities to better serve small business customers within the GRC framework. Prior to PG&E filing this application, SBUA and PG&E entered into an MOU regarding activities to better support the needs of PG&E's small business customers, and jointly propose its adoption in this proceeding with one modification as described below. PG&E and SBUA state that this MOU builds on the successes of the 2014 MOU between the parties and reflects their continued commitment to improving service for small business customers.

Specifically, the MOU calls for PG&E to dedicate $8.08 million annually in the areas of outreach, creation of a new PG&E internal small business organization, creation of webpage and technology resources, economic development, tracking systems for small businesses, and contracting opportunities. Procedurally, the MOU provides for ongoing semi-annual meetings to discuss settlement implementation.

On September 1, 2015, PG&E and SBUA jointly submitted this MOU as part of Exhibit PG&E-6, Chapter 2, Attachment A. SBUA advocated in the proceeding to adopt the MOU's specific provisions and recommended sufficient funding be allocated to support improvements for small businesses.

No party has opposed the MOU. However, as described in Section 3.2.4.5 of the Settlement Agreement, PG&E and SBUA jointly propose that a provision of the MOU be revised in order to note PG&E's agreement to fully fund the work described under the MOU notwithstanding the $4 million reduction for Customer Account Services in MWC IV, as provided for in Section 3.1.5 of the Settlement Agreement.

The proposed modification would read as follows:

2.1 Spending Target

> The Parties agree that PG&E will direct the equivalent of $8.08 million annually, or a total of $24.2 million for the years 2017-2019 (or a total of $32.32 million for the years 2017-2020), from its Customer and Community Services, Energy Solutions & Service budget to provide outreach and support for PG&E's Small Business customers through its SMB programs. The Parties agree that PG&E will direct that funding toward Small Business outreach as follows:

No party has opposed the MOU or the proposed modification. Section 3.2.4.5 of the Settlement Agreement provides that this MOU is adopted.

4.2.4.6. Center for Accessible Technology Memorandum of Understanding (Section 3.2.4.6)

PG&E and CforAT have also worked collaboratively over the last several GRCs to address accessibility issues within the GRC framework and to continue to improve service for PG&E's disabled customers. Prior to PG&E filing this application, CforAT and PG&E entered into a MOU regarding activities to improve accessibility and jointly proposed its adoption in this proceeding. On September 1, 2015, CforAT and PG&E jointly submitted this MOU as part of Exhibit PG&E-6, Chapter 5, Attachment A.

The MOU continues PG&E's and CforAT's commitment to continue working to improve upon a number of accessibility issues including: (1) PG&E's continued staffing of a Disability Access Coordinator to coordinate accessibility activities; (2) website accessibility (continued implementation of WCAG 2.0 standards, training, testing); (3) communication access issues (customer disability database, tracking preferred communications, large print and alternative communication methods); and (4) access to PG&E's local offices and neighborhood payment centers, around construction sites and pole locations. It also sets forth procedural requirements including an annual reporting process.

No party has opposed the MOU. Section 3.2.4.6 of the Settlement Agreement provides that this MOU is adopted.

4.2.4.7. Accuracy Testing of Meters (Section 3.2.4.7)

Pursuant to the Commission's General Order (GO) 58-A, PG&E is permitted to use statistical techniques to manage the accuracy of small and medium size gas meters by removing those gas meters where performance falls below prescribed standards. In testimony, PG&E provided evidence that its Scheduled Meter Change (SMC) program effectively identifies meters for removal and that the cost of continuing to test these meters once removed exceeds the billing adjustments that result from those tests,[178] and concludes that it is therefore more cost effective to eliminate in-testing of meters removed through the SMC program.

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178 Exhibit PG&E-6, Chapter 7 at 7-17.

No party opposed PG&E's proposal. It is adopted in Section 3.2.4.7 of the Settlement Agreement.

4.2.4.8. Reporting for Safety Net and Quality Assurance Programs (Section 3.2.4.8)

In Chapter 9 of Exhibit PG&E-6, PG&E proposed to reduce the reporting frequency for two reporting requirements previously mandated by the Commission.

The first reporting requirement concerns PG&E's "Safety Net Program," which was created in recognition of the inconvenience caused by extended power outages that occur during some storm events. Residential electric customers who experience a service interruption for a total of 48 hours or longer during a severe storm may receive a check for their inconvenience. Currently, reports regarding PG&E's performance under the program are filed quarterly pursuant to D.04-05-055.[179] In testimony, PG&E observes that these storm conditions rarely occur outside of the winter season, which concludes in the first quarter. For that reason, PG&E proposes to report annually, at the end of the second quarter.

The second reporting requirement concerns PG&E's Quality Assurance Programs report, which provides information on PG&E's Service Guarantee performance. PG&E reports on activities such as service disruption response time and number of complaints resolved within 10 working days. Currently,

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[179] D.04-05-055, Ordering Paragraph 1, Appendix B.

these reports are required to be filed quarterly.[180] PG&E proposes to reduce administrative burden by filing annually, rather than quarterly.

No party opposes these proposals. They are adopted in Section 3.2.4.8 of the Settlement Agreement.

4.2.4.9. Customer Service and Outreach (Section 3.2.4.9)

In testimony, NDC offered a number of comments about PG&E's marketing, education and outreach activities.[181] As discussed earlier in this decision, Section 3.1.5.6 of the Settlement Agreement includes a provision that PG&E will direct portions of its education and outreach funding to serving low-income and minority communities. Here, Section 3.2.4.9.1 of the Settlement Agreement further provides that PG&E will continue to invite low-income and community-of-color advocates to participate on a Customer Advisory Panel to provide ongoing guidance relating to PG&E's overall outreach efforts. Meetings of the Customer Advisory Panel will occur in person at least twice a year and will be attended by a representative of PG&E's executive leadership.
Section 3.2.4.9.2 of the Settlement Agreement provides that PG&E will provide testimony in its next GRC on its efforts to engage with community-based organizations on outreach activities.

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[180] *Ibid.*

[181] Exhibit NDC at 10.

4.2.4.10. Economic Circumstances (Section 3.2.4.10)

In testimony, NDC comments that it is important to consider the impact that rate increases will have upon low-income communities, which are predominantly made up of minority groups.[182] NDC also states, "[i]t is essential that proposed rate increases also be based in significant part on the economic health and well-being of the 70% of PG&E's customers who live from paycheck-to-paycheck."[183] As discussed earlier in this decision, prior to filing its GRC application, PG&E met with various low-income minority groups to discuss the impact of the economic recovery on low-income minority organizations.

Section 3.2.4.10 of the Settlement Agreement provides that PG&E will continue to meet annually with low-income minority organizations, and other interested parties, to discuss the economic circumstances in PG&E's service areas. As part of this meeting, the parties will review economic metrics including unemployment rates, median wages, and changes in cost of living levels in California. In particular, the discussion will include the possible impact of economic circumstances on future rate changes requested by PG&E.

4.2.4.11. Discussion of Customer Care Non-financial Items

We find that the agreed-upon changes to PG&E's Customer Care-related practices and reporting requirements are reasonable and we conclude that they should be adopted. Our findings and conclusions are based on our review of

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[182] *Id.* at 4.

[183] *Id.* at 5.

parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement.

4.2.5. Shared Services and IT (Section 3.2.5)

4.2.5.1. Supplier Diversity (Section 3.2.5.1)

4.2.5.1.1. Aspirational Goal and Future GRC Testimony

In testimony, NDC recommended that PG&E's Supplier Diversity goals must continue to rise, from 40 % to 50 %.[184] In rebuttal testimony, PG&E disagreed with NDC's recommendation, noting that utilities that spend 40 % with diverse business enterprises are considered national leaders in supplier diversity.[185] PG&E also noted that its 2015 performance of 44 % and $2.5 billion in certified diverse business enterprise spend, which is the fourth consecutive year the company has exceeded the $2 billion mark, places the utility not only in the top quartile, but as a national leader in supplier diversity.[186]

Section 3.2.5.1.1 of the Settlement Agreement provides that PG&E will report in the next GRC on its aspirational goal of 42 % supplier contracts with diverse business enterprises in 2017 and provide a new aspirational goal for the test year of the next GRC.

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[184] Exhibit NDC at 15.

[185] Exhibit PG&E-26 at 5-9.

[186] Exhibit PG&E-26 at 5-9.

4.2.5.1.2. Hiring of Minority-Owned Businesses

In testimony, NDC states that they "strongly support supplier diversity contracts that maximize the number of jobs in California and assists companies that serve and hire from their local communities. To best achieve a compromise, we would urge that the large Tier 1 companies be required to hold, with PG&E present, at least two meetings a year with potential contractors from the minority community."[187]

Section 3.2.5.1.2 of the Settlement Agreement provides that PG&E shall continue its efforts to hire minority-owned businesses for auditing, legal and other professional services and skilled labor needs, including meeting with key diverse business enterprise organizations attending the Commission's annual GO 156 *en banc* proceedings, no later than 60 days after the *en banc* hearing, to discuss cooperative methods for achieving GO 156 goals and addressing other issues raised by the CPUC.

4.2.5.1.3. Public Reports Relating to Diverse and Small Businesses

In testimony, NDC recommends that, PG&E "provide a breakdown both of supplier diversity and employment diversity for the largest Asian American subethnic groups such as Filipino American, Vietnamese American, Indian American, Chinese American, Japanese American, and Korean American."[188] In rebuttal testimony, PG&E disagreed with NDC's recommendation, noting among other things that this additional information will not be useful to

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187 Exhibit NDC at 14.

188 Exhibit NDC at 16.

determine labor markets or evaluate PG&E's hiring against a labor market and that demographic data for subethnic groups does not exist for labor markets.[189]

Section 3.2.5.1.3 of the Settlement Agreement acknowledges that PG&E reports publicly on various issues relating to diverse and small businesses and provides that PG&E will make its public reports on this topic available to NDC on an annual basis.

4.2.5.2. Discussion of Shared Services/Supplier Diversity Non-financial Items

We find that the agreed-upon changes to PG&E's Supplier Diversity-related practices and reporting requirements are reasonable and we conclude that they should be adopted. Our findings and conclusions are based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement.

4.2.6. Human Resources (Section 3.2.6)

4.2.6.1. Employment Diversity (Section 3.2.6.1)

4.2.6.1.1. Aspirational Goals

In its testimony, NDC recommends that PG&E set aspirational diversity goals for different employment categories.[190] PG&E responded in rebuttal testimony that it has already established good-faith aspirational diversity hiring

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[189] Exhibit PG&E-27 at 2-10.

[190] Exhibit NDC at 15. Settling Parties state that PG&E addresses NDC's recommendations regarding Suppler Diversity in Exhibit PG&E-26 at 5-9.

goals in support of PG&E's goal that employees at all levels reflect the diversity of the communities it serves.[191]

Section 3.2.6.1.1 of the Settlement Agreement provides that PG&E will continue to establish and further develop good-faith aspirational diversity hiring goals in support of PG&E's goal that PG&E's employees at all levels reflect the diversity of the communities PG&E serves. Diversity hiring goals will be established, measured, and reported in alignment with the factors used by the U.S. Department of Labor Office of Federal Contract Compliance Program and demographics available for the U.S. Census Bureau.

4.2.6.1.2. Pipelines for Diverse Candidates

In its testimony, NDC commented on the importance of employment diversity noting that a more diverse workforce will encourage and support contracting with more diverse suppliers.[192]

Section 3.2.6.1.2 of the Settlement Agreement provides that PG&E shall continue to provide and support activities that build both near-term and future pipelines of diverse candidates throughout its service territory.

4.2.6.1.3. Future GRC Testimony

Section 3.2.6.1.3 of the Settlement Agreement provides that PG&E shall provide testimony in its next GRC on its efforts to promote diversity hiring at all levels and promote the development of near-term and future pipelines of diverse

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[191] Exhibit PG&E-27 at 2-9.

[192] Exhibit NDC at 15.

candidates. This testimony will include a comparison of PG&E's actual hiring for the 2017 base year against the aspirational goals referenced above.

4.2.6.2. Compensation (Section 3.2.6.2)

In its testimony, NDC offered a number of comments with respect to PG&E's executive compensation.[193] Among those, NDC noted that while PG&E's current incentive structure appears to emphasize safety, including safety metrics totaling 50 % of the STIP, NDC was concerned that no individual safety metric outweighs the single financial performance metric.[194]

In its rebuttal testimony, PG&E disagreed with NDCs recommendations. Among other things, PG&E noted PG&E has increased the weight of its total safety metric from 10 % to 50 % in the last four years. According to PG&E, the fact that it is comprised of more than one metric has no bearing on the fact that safety metrics are the single biggest focus of the Company's STIP Program.[195]

Section 3.2.6.2 of the Settlement Agreement addresses NDC and PG&E's comments on executive compensation. This section provides that PG&E's executive leadership and NDC may discuss safety metrics related to executive compensation and related issues during annual meetings between NDC and PG&E. It also provides that PG&E will continue during the term of the 2017 GRC to have shareholders fund the executives' STIP and all of the LTIP.

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193 Exhibit NDC at 6-9.

194 *Id*. at 7.

195 Exhibit PG&E-27 at 3-28.

4.2.6.3. Discussion of Human Resources, Non-financial Items

With the clarifications we provide below, we find that the agreed-upon changes to PG&E's Human Resources-related practices and reporting requirements are reasonable and we conclude that they should be adopted. Our findings and conclusions are based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement.

Regarding Compensation (Section 3.2.6.2 of the Settlement Agreement), as noted earlier in this decision, the December 1, 2015 Scoping Memo determined that this proceeding would consider whether PG&E's proposed risk management, safety culture, governance and policies, and investments will result in the safe and reliable operation of its facilities and services. The Scoping Memo also stated that this proceeding will document and review how PG&E finances safety efforts, particularly how the Commission evaluates compensation of PG&E's executive leadership around questions of safety. Thus, we commend NDC in particular for raising these issues in testimony and pursuing resolution of their concerns through the settlement process.

We reviewed and approved the overall financial settlement regarding the non-executive STIP revenue requirement earlier in this decision. Here, we focus on NDC's concerns regarding the role of safety metrics in the incentive structure that underlies the STIP. The proceeding record that existed prior to the filing date of the Settlement Agreement was later supplemented by the transcript of the Settlement Workshop, by PG&E's presentations at that workshop (Exhibit

PG&E-39), and by Exhibit PG&E-43 ("Late-filed Exhibit on Executive Compensation and Safety").

One of the leading indicators of a safety culture is whether the governance of a company utilizes any compensation, benefits, or incentives to promote safety and hold employees accountable for the company's safety record. As a matter of law, the Commission and the gas utilities are charged with creating a "culture of safety that will minimize accidents, explosions, fires, and dangerous conditions…."[196] As a matter of policy, the Commission promotes safety cultures at all utilities, not just the gas utilities singled out in statute. Among other things, the Commission is committed to "[holding] companies (and their extended contractors) accountable for safety of their facilities and practices," "[providing] clear guidance on expectations for safety management and outcomes," and "[promoting] a culture of safety vigilance by CPUC staff, and in the industries we regulate."[197]

We determined in the recent Sempra GRC that it is appropriate to review how the executives and the non-represented employees at the utilities under our jurisdiction are compensated under variable compensation.[198] We explained that we seek to prevent the adoption of incentives that may promote or induce bad corporate culture regarding safety, and that utilities should not be allowed to incent employee performance that leads to, aids, or causes unsafe incidents.[199]

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[196] Pub. Util. Code § 961.

[197] Safety Policy Statement of the California Public Utilities Commission, adopted July 10, 2014.

[198] D.16-06-054 at 147.

[199] *Id.* at 150.

We emphasized that the Commission preserves its right to ensure that the utilities' governance and management properly promote safety via incentive compensation and that the Commission will, in future GRCs and other proceedings, scrutinize utility awards of any compensation relative to the outcome of investigations into safety incidents.[200]

Regarding the metrics that underlie PG&E's STIP, discussion at the Settlement Workshop addressed NDC's concern that no individual safety metric in the STIP outweighs the single financial performance metric. PG&E provided additional explanatory detail in Exhibit PG&E-43, prepared and filed by PG&E after the workshop.

The weighting of the metrics in PG&E's 2015 STIP are provided below.[201]

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[200] *Id.* at 151.

[201] Exhibit PG&E-43 at AtchD-4 and AtchD-5.

PG&E 2015 STIP Measures

1. Safety (Share of Total = 50%)	
a. Public Safety	
i. Nuclear Operations	
ii. Diablo Canyon Power Plant Reliability and Safety Indicator Units 1 & 2	8%
iii. Electric Operations	
iv. Transmission & Distribution Wires Down	5%
v. 911 Emergency Response	5%
vi. Gas Operations	
vii. Gas In-Line Inspection and Upgrade Index	6%
viii. Gas Dig-ins Reduction	5%
ix. Gas Emergency Response	5%
b. Employee Safety	
i. Lost Workday (LWD) Case Rate	8%
ii. Serious Preventable Motor Vehicle Incident (SPMVI) Rate	8%
2. **Customer (Share of Total = 25%)**	
a. Customer Satisfaction Score	15%
b. System Average Interruption Duration Index	10%
3. **Financial (Share of Total = 25%)**	
a. Earnings from Operations ($M)	25%
TOTAL	**100%**

Reviewing the record as a whole, we find that PG&E has provided considerable detail on the metrics in the STIP, explaining how they are developed and evaluated, and how safety affects the STIP. No party proposed modifications to these metrics in their testimony.

For these reasons, we do not believe we should disturb PG&E's STIP metrics in this decision. It is our intention that the record in future GRCs will be better-developed by the utility and intervenors so that it is not necessary to direct the preparation of additional exhibits late in the proceeding, as was the case here.

That said, in the end we did assemble an in-depth record that allowed review of the safety and compensation matters first identified in the September 1, 2015 Scoping Memo, and we thank PG&E and intervenors for their efforts in that regard.

We will require PG&E to provide additional information as part of its next GRC application in order to help the Commission and the parties to gain a better understanding, at the outset of the proceeding, of whether and how safety policies, practices and performance are considered in the total compensation that is paid to non-represented employees and executives,. This information shall also include information about the governance and level of engagement by PG&E's Board in influencing the variable compensation programs of PG&E.[202]

In its next GRC application PG&E is directed to provide testimony regarding the compensation-related actions taken during the 2017-2019 GRC cycle, supported by relevant workpapers, data, company documents, and reports containing the following information:

1. Describe what Board committees (for example, compensation committee, safety committee, or other committees) at PG&E Corporation, and at PG&E, are responsible for determining the guidelines for establishing any compensation, bonuses, severances, and benefits.
2. Describe what direction PG&E Corporation provides to PG&E in formulating their compensation, bonuses, severances, and benefits.

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202 We adopted the same reporting requirements in our recent decision on the Sempra utilities' GRC. *See,* D.16-06-054 at 155-156.

3. Describe the qualifications of the Board members at PG&E Corporation and at PG&E who are responsible for determining the guidelines for establishing compensation, bonuses, severances, and benefits, and what committees they sit on.
4. Describe the coordination, if any, between the different committees that are responsible for developing the guidelines for establishing compensation, bonuses, severances, and benefits, and the frequency that these committees meet.
5. Describe the performance metrics and the measures used to set compensation, bonuses, severances, and benefits for non-represented employees and executives, and how these are used to determine them.
6. If applicable, describe how the compensation structure: creates long term and sustainable value for the utility; incentivizes employees; makes executives and managers personally accountable for safety and operational risks; creates a safer working environment and utility system; results in a demonstrated improvement of the utility's processes, policies, and performance; discourages below standard performance, or actions that are contrary to the interests of the utility and the utility's customers; holds employees, managers, and executives accountable for failure to comply with management's guidance, policies and instructions, and for below standard performance.
7. Describe how engaged and effective PG&E Corporation's Board is on operations, performance metrics, and safety-related incidents, including: how often PG&E Corporation's Board requests reports and/or presentations from PG&E regarding safety incidents, the effectiveness of risk management plans, and the effectiveness of operational processes; what PG&E Corporation's Board did or directed in response to these reports and/or presentations; and whether and how frequently PG&E Corporation's Board followed-up or sought updates on the reports, presentations, and the Board's actions and directions.
8. Describe how risk management information is used by PG&E Corporation and PG&E, as follows: how PG&E shares this information with its employees; describe the type of training or

> education that employees receive about management of risks; describe what processes are in place, if any, that allow the employees in the field to provide feedback on the management of risks, and the reporting of unsafe practices or unsafe incidents.

During the Test Year 2017 GRC cycle, the assigned Commissioner's office may request the staff of SED or the Energy Division to issue data requests to PG&E to provide further information regarding the operations and policies of the utilities, and the interrelationship with PG&E Corporation. All of the above information will provide the Commission with a better understanding of how risks are assessed and managed, and how safety and risks are considered in the awarding of any compensation, bonus, severance, or benefit.

4.2.7. A&G Expenses (Section 3.2.7)

4.2.7.1. Allocation of Legal Costs (Section 3.2.7.1)

In testimony, MCE asserted that the allocation of legal costs to the generation UCC does not appropriately capture the time spent on PPAs. MCE therefore proposed to add $645,000 to the A&G expenses otherwise allocated to the electric generation UCC.

In rebuttal testimony, PG&E disagreed. Among other things, PG&E asserted that PG&E's allocation of A&G costs is a reasonable allocation of common costs, appropriately reflects cost causation, and should be adopted by the Commission. PG&E states that for several rate case terms, and consistent with the cost allocation methodology followed by FERC, PG&E has allocated common costs—including corporate services departments' expenses (which include A&G costs) and common and general plant—to the UCCs based on the ratio of recorded O&M labor by UCC to the total company O&M labor. PG&E noted that for the Law Department, it has allocated $12.5 million, or 24.67%, to the generation UCC, the same allocation based on functional O&M labor that applies equally to every corporate services department's costs.[203]

Section 3.2.7.1 of the Settlement Agreement provides that PG&E's allocation of 24.67% of Law Department costs to generation rates will be adopted for the 2017 GRC, without further adjustment. It also provides that PG&E will prepare a study in order to assess whether the 24.67% allocation to generation activities is reasonable for PG&E's next GRC. PG&E will share a draft of the study results with MCE for comment and, should PG&E choose not to incorporate the final study results in its next GRC forecast, PG&E shall provide affirmative testimony explaining why.

4.2.7.2. Allocation of A&G Expenses Related to Public Purpose Programs (Section 3.2.7.2)

In testimony, MCE proposed that the O&M labor associated with the energy efficiency/Public Purpose Programs (PPP) be transferred to generation labor for purposes of the allocation of A&G expense and common plant. In rebuttal testimony, PG&E disagreed on the basis that (1) PPP costs are recovered through distribution rates; (2) PPP charges are by statute a non-bypassable charge for electric and gas customers; and (3) the Commission has determined that CCA customers can fully participate in these activities, both through PG&E's programs and programs operated by the CCA but funded from PG&E's PPP charges.

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[203] Exhibit (PG&E-29), at 19-3, line 2 to 19-4, line 5.

Section 3.2.7.2 of the Settlement Agreement provides that PG&E will prepare a workpaper that demonstrates where the final decision allocates the adopted A&G related overhead costs associated with energy efficiency programs.

4.2.7.3. Auditing (Section 3.2.7.3)

NDC supports supplier diversity contracts that maximize the number of jobs in California and assists companies that serve and hire from their local communities.[204]

Section 3.2.7.3 of the Settlement Agreement addresses these comments as they relate to PG&E's auditing function. Specifically, the section provides that PG&E will (i) hire independent and reputable outside accounting firms to conduct auditing work and (ii) support such firms in subcontracting with minority-owned and other diverse auditing firms. It also provides that PG&E will encourage their main outside accounting firm to subcontract a significant portion of auditing work to minority-owned subcontractors consistent with PG&E's dedication to supplier diversity. PG&E will also provide testimony in its next GRC filing on its efforts to contract with independent and reputable firms for auditing work and to support subcontracting with minority-owned and other diverse auditing firms.

4.2.7.4. Discussion of A&G Non-financial Items

We find that the agreed-upon changes to PG&E's A&G-related practices and reporting requirements are reasonable and we conclude that they should be

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[204] Exhibit NDC at 13.

adopted. Our findings and conclusions are based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement.

4.2.8. Reporting Obligations and Other Matters (Section 3.2.8)

In most GRC proceedings, the Commission typically reviews and reconsiders reporting requirements regarding a variety of utility activities, and frequently imposes new obligations. Section 3.2.8 of the Settlement Agreement reviews a number of such requirements and adopts a number of changes.

4.2.8.1. Overarching Principles (Section 3.2.8.1)

CUE identified a number of areas where it recommended that PG&E perform additional activities in order to move to a steady state level of work, and to perform more work than PG&E proposed where the benefit greatly outweighs the costs.[205] In many instances, PG&E responded that the additional activities were not yet justified by PG&E's operational or risk analyses.[206]

To address this disagreement, Section 3.2.8.1 of the Settlement Agreement articulates overarching principles regarding PG&E's steady state replacement rates and Reliability Program investments that will be reflected in PG&E's upcoming RAMP submittal. In summary, those principles provide for the following:

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205 Exhibit CUE-8-Errata to Prepared Testimony of David Marcus at i-iii.

206 Exhibit PG&E-23 V1 at 12-10.

1. PG&E should strive for reasonable rates of steady state replacement, consistent with risk-informed decision making, for crucial operating equipment necessary to provide safe and reliable service.
2. For the Reliability Program investments in the Electric LOB, PG&E should strive to install equipment necessary or useful to providing reliable service consistent with a holistic and measured approach to system reliability solutions.

4.2.8.2. Safe and Reliable Service (Section 3.2.8.2)

Section 3.2.8.2 of the Settlement Agreement addresses a request from parties during settlement negotiations for a statement from PG&E regarding whether this Agreement will enable PG&E to provide safe and reliable service. This Section provides the following statement from PG&E that it expects the Settlement Agreement to enable PG&E to comply with its obligations under Public Utilities Code Section 451:

> PG&E agrees that this Agreement should enable PG&E to comply with its obligations under Public Utilities Code Section 451 to "furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment and facilities…as are necessary to promote the safety, health, comfort and convenience of its patrons, employees, and the public."

4.2.8.3. Annual Spending Accountability Reports (Section 3.2.8.3)

An oft-recurring theme in GRCs at the Commission involves disputes between utility applicants and intervenors regarding the extent to which a utility may exercise management discretion to reprioritize Commission-authorized GRC spending, after it has been granted authority to spend specific designated amounts. As explained below, it has been our intention in recent PG&E GRC proceedings to move away from a hindsight-based exercise where intervenors attempt to show that a utility has improperly spent budgeted amounts, to a more transparent process where the utility proactively reports and justifies such deviations in its GRC spending.

We explained the underlying dynamic in our decision on PG&E's 2011 test year GRC application:[207]

> It is generally recognized that when a utility files a GRC, expenditure estimates are based on plans and preliminary budgets developed at least two years in advance of when they will actually be incurred. When the utility finalizes its budget just prior to the year when costs will be incurred or adjusts the budget during the year, new programs or projects may come up, others may be cancelled, and there may be reprioritization. This process is expected and is necessary for the utility to manage its operations in a safe and reliable manner.

However, we also cautioned that "the fact that this flexibility is available to the utility does not mean that everything the utility ends up doing is necessary or reasonable" and we noted that the Commission has disallowed costs of activities that were requested and included in prior GRC authorizations, only to be deferred, and re-requested in another GRC.[208] In light of these concerns, the Commission imposed several new requirements on PG&E in D.11-05-018 as further steps to ensure that any reprioritization processes are reasonable and result in the best use of ratepayer funds.

First, the Commission sought information to help it better understand the ongoing effects of reprioritizations and deferrals during a GRC cycle. To do this,

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[207] D.11-02-018 at 27.

[208] *Id.* at 28.

the Commission ordered PG&E to provide its authorized budget for each of the three GRC years, in March of the relevant spending year, followed by a report on actual recorded amounts for that year, with explanations of significant deviations.[209] The reports cover expense and capital expenditures for PG&E's electric distribution, electric generation, and gas distribution lines of business. The Commission directed the Energy Division to report to the Commission if it observed any spending patterns that are of concern with respect to the provision of safe and reliable service.[210] The Commission extended this reporting requirement in D.14-08-032, its decision on PG&E's 2014 test year GRC.[211]

Second, in D.11-05-018 the Commission also directed PG&E to include in its next GRC full descriptions of any reprioritizations and deferrals of costs explicitly identified in the settlement agreement adopted in that decision:[212]

> PG&E should fully explain its reprioritization process, justify deferrals of specific activities and projects, and justify the implemented higher reprioritized activities and projects that were not identified in this GRC. For activities and projects that were deferred and are now being re-requested, PG&E should fully explain why they are needed now when they were able to be deferred before.

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209 *Id.*, Ordering Paragraph 42.

210 *Ibid.*

211 D.14-08-032 at 12: "PG&E will use the proposed reporting procedures it has used throughout this GRC cycle to account for its spending by MWC, comparing authorized amounts to budgeted and spent amounts, and explaining significant differences."

212 D.11-02-018 at 31.

Finally, the Commission cautioned PG&E that it "will be critical in its evaluation of previously requested activities or projects that were deferred and re-requested keeping in mind that the utility has the obligation to maintain its operations and its plant in the condition to provide efficient, safe and reliable service, even if that condition requires more expenditures than the Commission has authorized."[213]

Settling Parties address these reporting requirements in the Settlement Agreement stating that during the settlement process they agreed that PG&E should continue to provide annual reports regarding budgeted and actual spending. Section 3.2.8.3 of the Settlement Agreement requires PG&E to provide "Spending Accountability Reports" patterned on the report of the same name described in D.14-12-025 and the Budget Reports previously required by D.11-05-018, Ordering Paragraph 42.

As its title implies, the Risk Spending Accountability Report ordered in D.14-12-025 compares the utility's GRC projected spending for approved risk mitigation projects to the actual spending on those projects, and explains any discrepancies between the two. Pursuant to D.14-12-045, it consists of a project-by-project comparison of authorized vs. actual spending, accompanied by the utility's narrative explanation of any significant differences between the two.[214]

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[213] *Ibid.*

[214] D.14-12-025 at 44. This report should be distinguished from a second report ordered by D.14-12-025, the "Risk Mitigation Accountability Report". That report is not addressed in the Settlement Agreement.

According to Settling Parties, as described in Section 3.2.8.3 of the Settlement Agreement, the new agreed-upon Spending Accountability Reports will compare authorized expense and capital to actual spending for all electric distribution, electric generation and gas distribution work. For safety and reliability work, these reports will also compare units of work authorized with units of work performed. PG&E will provide an explanation of any significant deviations between authorized and actual spending and between authorized and actual units of work.

PG&E will file these reports annually by March 31 of the year following the period covered by the report. The reports shall be served on the Directors of SED and Energy Division and the service list for the most recent GRC. The reports shall continue until discontinued by order of the Commission. Settling Parties propose that these Spending Accountability Reports shall replace the Budget Reports required by D.11-05-018 and D.14-08-032.

4.2.8.4. Principles for Deferred Work (Section 3.2.8.4)

In its testimony, TURN raised a broad concern regarding what it described as PG&E's practice of delaying or deferring work based on "reprioritization." TURN alleged that "PG&E's request in this case includes several forecasted amounts that are significantly higher than they otherwise would be to make up for work that was deferred during the period prior to the test year."[215] As one example, Settling Parties note that TURN recommended various capital disallowances for previously funded safety-related work that was not performed

[215] Exhibit TURN-1 at 14.

by PG&E in the 2014-2016 period concerning Aldyl-A Mains, High Pressure Regulators, Valves and Reliability Main Replacement on the grounds that deferring such work was contrary to principles set forth in D.11-05-018 and D.14-08-032.[216]

In rebuttal testimony, PG&E opposed such disallowances, explaining that the primary driver for decreased investment in these areas was increased investments in other areas following a risk-informed reprioritization.[217]

In Section 3.2.8.4 of the Settlement Agreement Settling Parties resolve this matter by expressing their agreement with a number of "principles," which they note were reflected in the Commission's decision on PG&E's 2014 GRC application. The listed principles appears to have been assembled from the Commission's discussion of several items in several places in that decision, including PG&E's pole replacement revenue requirement request (Section 4.7) and PG&E's financial health (Section 11.6). Settling Parties also rephrased some of that discussion. The principles listed in the Settlement Agreement are repeated below:[218]

1. Where funds are originally collected from ratepayers based on representations that the work is necessary to provide safe and reliable service and, yet, PG&E does not perform all of the designated work, the fact that PG&E must pay for a higher priority activity or program does not nullify or extinguish its responsibilities to fund forecasted and authorized work unless

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216 *Id.* at 14-24; Exhibit TURN-2, at 26.

217 Exhibit PG&E-22 V1 at 1-6 to 1-15.

218 Settlement Agreement, Section 3.2.8.4.

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 ability to provide safe and reliable service while affording a reasonable opportunity to earn its rate of return and thereby attract capital to fund its infrastructure needs. Adopted revenue requirements and the disposition of disputed ratemaking issues should be consistent with the goal of supporting PG&E's ability to provide safe and reliable service while maintaining its financial health and ability to raise capital.

Also in Section 3.2.8.4, PG&E agrees that, in the next GRC and its next Gas Transmission and Storage rate case, PG&E will need to take additional steps in order to seek ratepayer funding for work that was previously authorized and funded when all of the following are true:

a. The work was requested and authorized based on representations that it was needed to provide safe and reliable service;

b. PG&E did not perform all of the authorized and funded work, as measured by authorized (explicit or imputed) units of work; and

c. PG&E continues to represent that the curtailed work is necessary to provide safe and reliable service.

Specifically, for any work that meets these conditions, PG&E's direct showing in support of the reasonableness of its forecast in the rate case shall provide at a minimum, a demonstration of how the specific funding request is consistent with the principles above, and may include a showing of (i) why the authorized work was not performed in the time forecasted, (ii) how the authorized funding was used, if at all, for other purposes and (iii) whether such other purposes related to the provision of safe and reliable service.[219]

To the extent that authorized funding for safety-related work was used for other purposes, PG&E's showing in support of its forecast for additional funding for the curtailed work shall include a demonstration of the reasonableness of the alternative work for the purpose of evaluating the appropriateness of the new funding request. However, nothing in this provision is intended to modify PG&E's obligation, consistent with cost of service ratemaking, to demonstrate the reasonableness of recorded capital spending, whether or not done as a replacement for previously authorized and funded safety-related work.[220]

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[219] *Ibid.*

[220] *Ibid.*

4.2.8.5. Executive Level Engagement with Diverse Communities (Section 3.2.8.5)

In NDC's testimony, NDC commented on the importance of having access to PG&E's executive management as part of the GRC process and recommended that NDC should have an opportunity to meet at least once a year with PG&E's Chief Executive Officer (CEO).[221]

Section 3.2.8.5 of the Settlement Agreement provides that one annual meeting will be held between NDC leadership and PG&E to discuss issues related to the Settlement Agreement. The section provides that PG&E's executive leadership shall participate in the annual meetings: one or more of PG&E's Presidents shall attend each annual meeting, along with those senior officers relevant to the agenda. In addition, the CEO of PG&E Corporation shall attend one of the annual meetings during the term of the 2017 rate case.

4.2.8.6. Safety (Section 3.2.8.6)

During the settlement process, Settling Parties acknowledged the importance of PG&E's continued efforts to improve its safety culture. Specifically, Section 3.2.8.6 of the Settlement Agreement provides for the following:

- Officers and Directors who lead PG&E's safety culture shall continue to participate and further engage in annual trainings in support of safety culture improvement
- PG&E shall provide focused safety leadership training – which includes instruction on the importance of receiving input on safety issues from field personnel - to those managers and

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[221] Exhibit (NDC), at. 5, line 20 to 6, line 10.

supervisors whose employees have the highest exposures and hazards.

- PG&E leadership shall continue to and actively solicit employee feedback on safety issues through field safety meetings, grassroots safety teams and its new Enterprise Corrective Action Program.
- PG&E shall continue to include safety training in all new leader orientation programs.

4.2.8.7. Enterprise Corrective Action Program (Section 3.2.8.7)

In testimony, PG&E defines a "corrective action program" (CAP) as a series of processes that enable a business to systematically identify issues, determine appropriate corrective actions, facilitate the implementation of those corrective actions, and determine whether the implemented corrective actions sufficiently address the identified issue.[222] At this time, two lines of business within PG&E have implemented CAP: Nuclear Operations and Gas Operations.

In this GRC, PG&E proposes to establish a companywide "Enterprise Corrective Action Program," designed to standardize and formalize the process by which safety and operational issues are identified, categorized, tracked and resolved through corrective actions.[223] In its testimony, ORA recommended certain expense reductions to the program, which are now reflected in the agreed-upon reduction set forth in Section 3.1.6.1 of the Settlement Agreement.

Section 3.2.8.7 of the Settlement Agreement imposes deadlines on the roll-out of the program. Parties agree that by December 2017, PG&E will

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[222] Exhibit PG&E-7 at 8A-3.

[223] *Id.* at 8A-1.

implement its CAP to the electric LOB. By December 2018, PG&E will implement the CAP in all its businesses.

4.2.8.8. Risk Management and Integrated Planning Process (Section 3.2.8.8)

PG&E presented testimony about its risk management and integrated planning process, including testimony describing PG&E as "the industry leader" in these areas.[224] TURN submitted testimony describing PG&E's process as "opaque" and recommending various improvements, including an explicit prioritization of PG&E's proposed programs and projects.[225] In rebuttal, PG&E stated that TURN's more general recommendations belonged in the Commission's Safety Model Assessment Proceeding, but also acknowledged certain areas that could benefit from improvement.[226]

Section 3.2.8.8 of the Settlement Agreement requires that PG&E categorize its proposed risk mitigation programs and projects as either mandatory or discretionary. For the discretionary items, PG&E will be required to rank the items within a LOB by quintile (i.e., the programs and projects would need to be prioritized as within the top 20%, next 20%, etc.) or by a numeric ranking if such data is reasonably available. For work categorized as mandatory, PG&E will need to include information explaining such a categorization.

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[224] Exhibit PG&E-2, Chapters 3, 4 and 5, including Chapter 5, Attachment A, at 2.

[225] Exhibit TURN-1 at 2-14.

[226] Exhibit PG&E-21, Chapters 3 and 4.

PG&E also presented testimony regarding its risk methodology and prioritization.[227] CAUSE submitted testimony regarding safety and identification and mitigation of hazards, recommending that PG&E engage in an ongoing examination of its safety practices to achieve continuous improvement.[228]

Section 3.2.8.8 requires PG&E to attempt to improve its ability to identify specific actions or specific locations that require remediation on an urgent basis, and to attempt to develop measurements to evaluate and compare the cost-effectiveness of specific initiatives to mitigate risk.

4.2.8.9. Disclosure of Safety Metrics (Section 3.2.8.9)

PG&E presented testimony regarding its measurement and benchmarking of performance in relation to various safety metrics.[229] During the settlement process, CAUSE and other Settling Parties agreed that PG&E should disclose its performance under various safety metrics. Specifically, Section 3.2.8.9 requires that PG&E shall provide to Settling Parties on request monthly data, if available, for each LOB showing the following safety metrics:

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[227] Exhibit PG&E-2, Chapters 3, 4 and 5.

[228] Exhibit CAUSE-1 at 1-11.

[229] Exhibit PG&E-2, Chapter 2, at 2-3.

1. Incidents of wires down
2. 911 Emergency Response
3. Dig-in reductions
4. Gas emergency response
5. Diablo Canyon Safety and Reliability Indicators
6. Hydro public safety index
7. Lost work day case rate
8. OSHA recordable rate (injuries per 200,000 production hours)
9. Near-hits reported
10. Preventable motor vehicle accidents
11. Serious preventable motor vehicle accidents
12. Contractor lost work days
13. Contractor days away
14. Contractor OSHA recordable rate
15. Number of fires requiring engine response attributed to PG&E operations, and
16. Employee fatalities and life-altering injuries attributed to PG&E operations.

4.2.8.10. Safety Standards and Benchmarking (Section 3.2.8.10)

CAUSE presented testimony proposing that the Commission rely on international standards to supervise the development of management systems that will require utilities to develop, maintain and document compliance with regulatory mandates.[230] In rebuttal testimony, PG&E stated that it follows many

[230] Exhibit CAUSE-1 at 5.

recognized standards, but that PG&E must balance the cost of certification against its benefits.[231]

Section 3.2.8.10 requires that where possible, PG&E will consider using voluntary consensus standards when developing management systems or processes to improve safety, security, cybersecurity, facility inspections, and asset management. In its next GRC, PG&E shall disclose management system standards and other safety standards that it uses, and, until such time, PG&E shall provide various information to Settling Parties.

4.2.8.11. Discussion of Reporting Obligations

With the clarifications and follow-up activities provided below, we find that the agreed-upon changes to PG&E's reporting-related practices and reporting requirements are reasonable and we conclude that they should be adopted. Our findings and conclusions are based on our review of parties' positions as summarized in the JCE, as well as the underlying written testimony and workpapers, plus discussion at the Settlement Workshop and testimony at the evidentiary hearing, and comparing that to what the Settling Parties have agreed to in the Joint Motion and Agreement. We commend Settling Parties for their agreements regarding improvements to PG&E's current reporting obligations.

With respect to Section 3.2.8.3 of the Settlement Agreement, "Annual Spending Accountability Reports," we clarify that in approving this provision of the Settlement Agreement, we are not changing the requirement of D.11-05-018

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[231] Exhibit PG&E-21, Chapter 2, at 2-1 to 2-2.

that PG&E shall provide annual budgeted amounts, by MWC, for each year by January 31 of that year. In approving Section 3.2.8.3, our intent is to combine two reporting requirements into one, to avoid redundancy and improve efficiency. Our instruction in D.11-05-018 to the Energy Division still holds as well: Energy Division shall report to the Commission if it observes any spending patterns that are of concern with respect to the provision of safe and reliable service.

Finally, with respect to several of the agreed-upon measures, we note several instances where PG&E agrees to provide data or updates to other Settling Parties (e.g., Section 3.2.8.9, Disclosure of Safety Metrics and Section 3.2.8.10, Safety Standards and Benchmarking). It is not clear to us why this information would not be provided directly to the Commission and its staff, with additional provisions made for availability to other interested parties. To provide clarity, we direct that the Commission's SED meet and confer with PG&E and other interested parties following the issuance of this decision so that SED may ensure that PG&E's ongoing reporting activities, as reflected throughout the Settlement Agreement, are implemented in a manner that best suits SED's purposes. That discussion should include all reporting requirements in the Settlement Agreement, not just the provisions of Section 3.2.8.

4.3. Contested Issues (Article 4)

Article 4 of the Settlement Agreement sets forth the two contested issues over which the Settling Parties were unable to reach consensus. The Settlement Motion states that the parties contesting these issues contend that evidentiary hearings on these issues are not necessary even though allowed for under Commission Rule 12.2. Rather, the parties suggested that these issues can be resolved through information to be provided in opening and reply comments on the Settlement Agreement.

We address each contested issue below.

4.3.1. Third Post-Test Year (Section 4.1 of the Settlement Agreement)

The parties were unable to gain consensus on whether the term of this GRC should be three or four years. PG&E and ORA recommend that the term of this GRC be four years: the 2017 test year and three post-test years, 2018-2020. TURN, A4NR, CAUSE and CFC recommend that the term this GRC remain at three years - the 2017 test year and two post-test years, 2018-2019.

We find that it would be premature to resolve this matter in this decision. In D.16-06-005, we denied a petition to modify D.14-12-025 to change the GRC cycle from three years to four years. After our review of that petition, we concluded that it is premature to revisit the need for a four-year rate cycle because, at that time, the S-MAP applications had not yet been resolved, and the first RAMP had not yet been filed. Since that time, the first phase of the S-MAP proceeding has concluded,[232] but the first RAMP is only just getting underway.[233]

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[232] D.16-08-018 directs utilities to "test drive" a multi-attribute approach toward more uniform and quantitative methods of risk management. It also adopts the Commission's Safety and Enforcement Division guidance for RAMP proceedings – with modifications – and requires RAMP filings include ten major components together with calculations of risk reduction and ranking of mitigations based on risk reduction per dollar spent. Phase Two of the proceeding has begun and is intended, in part, to implement a multi-attribute approach, develop comparable risk scores across utilities, and revisit RAMP filings and requirements.

[233] *See,* Investigation (I.) 16-10-015 and (I.) 16-10-016, *Orders Instituting Investigation Into the November 2016 Submission of San Diego Gas & Electric Company's and Southern California Gas Company's Risk Assessment and Mitigation Phases*. Under the procedures adopted in D.14-12-025 and D.16-08-018, SDG&E and SoCalGas are required to file their RAMP submissions in these

Footnote continued on next page

Furthermore, in D.16-06-005 the Commission also directed its Energy Division to conduct a workshop to explore options, including moving toward a longer GRC cycle, to facilitate the timely completion of GRC and related proceedings, and to provide a report following the workshop. The workshop took place on January 11, 2017 but the post-workshop report has not yet been completed and made available. Based on these considerations and the pendency of the Energy Division workshop report, we should not prejudge the outcome of that workshop process by changing the term of this GRC to four years. Therefore, PG&E should submit its next GRC application according to the existing schedule adopted by the Commission in D.14-12-025.

4.3.2. Gas Leak Management (Section 4.2 of the Settlement Agreement)

The parties were unable to reach consensus on whether PG&E should be authorized in this GRC decision to establish a new balancing account to record costs to comply with gas leak management requirements that may emerge from Commission Rulemaking R.15-01-008.

CUE, EDF and PG&E recommend that such a balancing account be established in this proceeding. TURN, CAUSE and CFC oppose the recommendation.

Investigations, followed by the Commission's SED review for consistency and compliance with the S-MAP. Parties to the Investigations will be given an opportunity to comment on SDG&E's and SoCalGas' RAMP submissions as well as SED's report. The RAMP filing and comment process will then form the basis of SDG&E's and SoCalGas' assessment of their safety risks in their next respective GRC filings, currently scheduled for September, 2017.

In Section 4.2 of the Settlement Agreement, CUE, EDF and PG&E agree to support Commission approval of following provisions (ORA opposes Section 4.2.1 and has proposed a four-year cycle in R.15-01-008):

4.2.1 PG&E agrees to support adoption of a minimum 3-year leak survey cycle in R.15-01-008.

4.2.2 CUE, EDF and PG&E agree that, to enable PG&E to implement new regulatory requirements upon their adoption in Phase 1 of R.15-01-008, a New Environmental Regulatory Balancing Account (NERBA) should be adopted. PG&E shall be authorized to track and record to the NERBA incremental Gas Distribution Emission Reduction Costs associated with new regulatory requirements pertaining to gas distribution leak management activities, adopted in Phase 1 of R.15-01-008, until the Commission makes a decision regarding costs in Phase 2.

4.2.3 PG&E will file a Tier 1 Advice Letter after the Commission's issuance of a final decision in the 2017 GRC to establish the NERBA.

4.2.4 PG&E is authorized to recover the costs recorded to the NERBA annually by including them in PG&E's Annual Gas True-up advice letter filing. ORA may audit such account.

In considering these proposals, we take notice of the record in R.15-01-008, especially procedural developments in that proceeding subsequent to the filing of the August 3, 2016 Settlement Motion in the instant proceeding. On November 21, 2016 the assigned ALJ in R.15-01-008 issued a ruling that, among other things, sought comments from parties on the scoping memo question of whether a two-way balancing account ("New Environmental Regulations Balancing Accounts" or "NERBA") should be established for interim cost recovery in that proceeding. Parties filed comments responsive that question on December 9, 2016 and reply comments on December 22, 2016.

We conclude that we should not decide this question in this GRC decision because it is now actively pending in R.15-01-008. The proposal to adopt the new balancing account is denied without prejudice.

4.4. General Provisions (Article 5)

Article 5 includes many general provisions common to these types of settlements. Indeed, many of these provisions can be found in the settlement of PG&E's 2011 GRC, approved by the Commission in D.11-05-018.

4.5. Conclusion Regarding the Settlement Agreement

Except for the specific provisions identified above and listed below, we conclude that the Settlement Agreement attached to the Settlement Motion is reasonable and in the public interest. Except as noted, the Settlement Agreement is also consistent with the law, and will provide the necessary funds to allow PG&E to operate its electric distribution system, gas distribution system, and its electric generation assets safely and reliably at reasonable rates. Therefore, the Settlement Motion to adopt the Settlement Agreement is granted, with the exceptions noted, and the Settlement Agreement, excluding those exceptions, should be adopted.

As discussed above, after our review of each provision of the Settlement Agreement, we determine that the following sections are either unreasonable in light of the whole record, inconsistent with law, and not in the public interest:

a. Section 3.1.3 (Electric Distribution) PG&E shall establish a Rule 20A balancing account that tracks the annual capital and expense costs for Rule 20A undergrounding projects, on a forecast and recorded basis. In addition, PG&E, the City of Hayward, and Commission staff are directed to determine a joint estimate of the scope and funding required for an audit of PG&E's Rule 20A program.

b. Section 3.1.5.2 of the Settlement Agreement is not adopted. PG&E shall file a standalone application for recovery of recorded costs in its Residential Rates Reform Memorandum Account, or shall seek recovery in its next GRC application.

c. Section 3.1.9.3 of the Settlement Agreement is not adopted. Instead, as described in Ordering Paragraph 10 below, PG&E shall file an advice letter to establish a two-way tax memorandum account.

Rule 12.4 provides that upon rejection of a settlement, the Commission may take various steps, including the following:

(a) Hold hearings on the underlying issues, in which case the parties to the settlement may either withdraw it or offer it as joint testimony,

(b) Allow the parties time to renegotiate the settlement,

(c) Propose alternative terms to the parties to the settlement which are acceptable to the Commission and allow the parties reasonable time within which to elect to accept such terms or to request other relief.

We do not believe that holding hearings on the provisions that we have not adopted would be fruitful or productive, especially since we already addressed Rule 20A matters during evidentiary hearings. We also do not wish to provide parties additional time to renegotiate the settlement, because the three items that we have found unacceptable are not matters that we might find acceptable under different terms. Therefore, pursuant to Rule 12.4(c) the settling parties shall have 15 days from today's date to file with the Docket Office, and serve, a "Notice To Accept PG&E's Adopted Test Year 2016 Revenue Requirement," or to file a "Motion Requesting Other Relief." The filing made pursuant to Rule 12.4(c) shall only address the two provisions of the Settlement

Agreement that are not adopted in this decision, not any other aspect of the Settlement Agreement. In the event a "Motion Requesting Other Relief" is filed this proceeding shall remain open until a decision or ruling resolves the motion.

5. SmartMeter Update

This final section of our decision addresses a compliance item regarding PG&E's SmartMeter Upgrade program. This matter is not related to the Settlement Agreement. We briefly recount the relevant procedural history below before turning to our discussion of that item.

The Commission authorized PG&E to deploy an advanced metering infrastructure (AMI) project in D.06-07-027. That decision addressed PG&E's 2005 "Application for Authority to Increase Revenue Requirements to Recover the Costs to Deploy an Advanced Metering Infrastructure," A.05-06-028. PG&E's AMI project was intended to automate PG&E's gas and electric metering and communications network (5.1 million electric meters and 4.2 million gas meters) and consisted of investment in new metering and communications infrastructure as well as related computer systems and software. The underlying premise of PG&E's AMI project was that most of PG&E's existing meter inventory would be retrofitted with "communications modules" and redeployed in the field.

In 2007, PG&E brought a new request to the Commission, its SmartMeter Upgrade (SMU) program.[234] PG&E sought authority to make significant additional investments in its original AMI project in order to upgrade the existing electric meters to solid state meters (i.e., to entirely replace the older

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[234] A.07-12-009, "Application of Pacific Gas and Electric Company for Authority to Increase Revenue Requirements to Recover the Costs to Upgrade its SmartMeter™ Program."

meters with new meters), and to install related technology that, according to PG&E, would "create a foundation for building an infrastructure that will enable and empower new ways of looking at energy use."[235]

In general, the Commission reviewed the contemporaneously filed AMI and "smart meter" applications of each utility under its jurisdiction by comparing the projected costs of these investments to their projected benefits, requiring that an overall net benefit be shown before authorizing the utilities to proceed with these capital-intensive projects. With respect to PG&E's 2007 SMU application, the Commission (consistent with the views of PG&E and the other parties in the proceeding) applied an "incremental" analysis to its evaluation of PG&E's request, meaning that the Commission did not consider whether the total project benefits (i.e., AMI plus SMU) exceeded total project costs. The Commission based its decision only on the incremental costs and benefits of the SMU program alone.

In its decision on PG&E's application, the Commission found that the incremental benefits of the SMU project did exceed the incremental costs, and authorized PG&E to proceed with its proposed investments. In reaching its decision, the Commission reviewed PG&E's forecasted incremental costs and benefits, as well as the arguments of other parties in favor of alternative

[235] D.09-03-026 at 5. To summarize briefly, in A.07-12-009 PG&E proposed to significantly upgrade certain elements of its SmartMeter Program technology: incorporating an integrated load limiting connect/disconnect switch into all advanced electric meters; incorporating a HAN gateway device into advanced electric meters to support in-home network applications; and upgrading PG&E's electric meters to solid-state meters to support this functionality and to facilitate upgrades.

forecasts. Ultimately, the Commission adopted its own estimates and relied on those to approve PG&E's request.[236]

With respect to SMU project costs, the Commission found the total incremental costs of the SMU to be $749 million on PVRR basis.[237] The bulk of these costs, 85%, consisted of deployment costs (e.g., the meter devices themselves). Other significant costs consisted of ongoing O&M costs and "technology assessment" to provide for things such as feasible system upgrades, customer technology upgrades, and technical standards development. The Commission also included a "risk-based allowance" in the project costs, totaling $50 million, approximately 6.7% of the total project costs.[238]

With respect to SMU project benefits, the Commission found the total incremental benefits of the SMU to be $779 million.[239] These benefits fell into two broad categories: operational benefits (21% of the total) and energy

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[236] PG&E's AMI and SMU are multi-year investment projects. As such, they are evaluated on a "present value revenue requirement" (PVRR) basis. The PVRR of a project is defined as the total annual revenue, discounted to present dollars at the time of the calculation, that is necessary to cover costs and expenses of the project over that multi-year period (15 years for AMI and 20 years for SMU).

[237] D.09-03-026 at 152, Table 3. The calculations in the remainder of this paragraph are derived from that table.

[238] In its 2006 Decision approving PG&E's AMI investment, the Commission approved PG&E's request for a risk-based allowance for that project as well, totaling $128 million. The Commission explained the allowance as follows: "if one part of the project exceeds budget then there is a process for project managers to 'draw-down' or authorize the use of the contingency to complete the project. In effect, by approving the proposed budget, the Commission explicitly allows PG&E the discretion to spend $128.8 million to address delays, overruns or other unforeseen contingencies as a part of the reasonable costs of the project." D.06-07-027 at 12.

[239] *Id*. at 153, Table 4. The calculations in the remainder of this paragraph are derived from that table.

conservation/demand response benefits (79% of the total). The operational benefits consisted primarily of avoided field visits due to the remote connect/disconnect switches that would be built into the new meters, and related cash flow and bad debt improvements. The energy conservation/demand response benefits consisted of (1) electric conservation facilitated by HAN devices that would rely on information provided by the new SmartMeters ($269 million, or 34% of total benefits); (2) air conditioning cycling facilitated by HAN devices ($83 million, or 11% of total benefits); and, (3) the benefits expected from creation of a new "peak time rebate" (PTR) program ($263 million, or 34% of total benefits).

It is the PTR program that presents the compliance matter that we address in today's decision. PTR is a rate design that offers incentives to ratepayers to reduce their usage during high-demand hours that are designated by their utility as "peak day pricing" events. Each customer's energy reduction during each event is measured against a customer specific reference level that is calculated for each customer, for each event. Customers then receive a bill credit for each kilowatt-hour of reduced usage that they achieve during the event period. For PG&E, the PTR program would be made possible by the upgraded meter technology to be deployed as part of the SMU. As shown above, the Commission's decision to approve the SMU rested on an assumed total benefit where customer savings from the PTR program would provide one-third of the total benefits of the upgrade. Therefore, as part of its SMU decision the Commission ordered PG&E to present a proposal to implement a PTR program in its November 2009 rate design window filing.[240] PG&E complied by filing A.10-02-028 in February, 2010.[241]

We will not recount the long procedural history of A.10-02-028 here.[242] The proceeding concluded when the Commission issued D.15-07-008, which dismissed A.10-02-028 without prejudice in response to a joint motion filed by PG&E and ORA. The Commission's action had the effect of relieving PG&E of its prior commitment to deploy a PTR program. However, in granting this relief, the Commission noted that the absence of a PTR program and its forecast benefits raised the question of whether the SMU program that it had approved in D.09-03-026 remained cost-effective.[243] Therefore, in D.15-07-008 the Commission also ordered PG&E to prepare an updated analysis of the cost-effectiveness of its SMU project without the previously-anticipated benefits of the PTR program, and to submit this analysis as part of its evidentiary showing in its 2017 GRC.[244] The Commission explained the basis for this order by noting its responsibility to ensure that PG&E's SmartMeter program is cost-effective and stating that

[240] D.09-03-026, Ordering Paragraph 9.

[241] Application of Pacific Gas and Electric Company for Approval of its 2010 Rate Design Window Proposal for 2-Part Peak Time Rebate and Recovery of Incremental Expenditures Required for Implementation.

[242] That procedural history is provided in D.15-07-008.

[243] D.15-07-008 at 16.

[244] *Id.*, Ordering Paragraph 5. The Commission specified a particular format for the required updated analysis: "PG&E shall prepare this analysis by updating Table 3 and Table 4 from D.09-03-026, adding line items as necessary…"

PG&E's ratepayers must be assured that the SMU was a worthwhile investment of ratepayer funds.[245]

As directed in D.15-07-008, PG&E served an exhibit in the instant proceeding on December 1, 2015 entitled "SmartMeter Cost Effectiveness Update in Compliance with Ordering Paragraph 5 of California Public Utilities Commission Decision No. 15-07-008" (Exhibit PG&E-16).

The analysis provided in Exhibit PG&E-16 was examined in the evidentiary hearings conducted on September 1, 2016. During the testimony of PG&E's witness it became apparent that PG&E had not complied with the direction of Ordering Paragraph 5 of D.15-07-008 because PG&E had not prepared its analysis by updating the incremental SMU costs and benefits presented in Table 3 and Table 4 from D.09-03-026, as directed by the Commission. Instead, PG&E provided a "total project" update of costs by providing the total recorded costs of AMI and SMU together — the approach that the Commission explicitly declined to follow, at PG&E's behest, in D.09-03-026. PG&E did provide an update of the incremental SMU benefits, removing the now-foregone benefits of PTR and replacing them with (1) forecast benefits associated with future deployment of residential and small/medium commercial customer time-of-use rates, and (2) projected incremental benefits associated with new federal and state tax rules that had not been known or forecasted in PG&E's original SMU application. Nevertheless, the information provided by PG&E in Exhibit PG&E-16 made it impossible for the Commission

[245] *Id.* at 17.

to determine whether the SMU project remained cost-effective without the benefits of the PTR program because PG&E failed to provide an update of the incremental SMU costs.

PG&E's explanation for its failure to provide the information required by D.15-07-008 was not convincing. PG&E explained that its recorded costs did not distinguish between the original AMI costs and the SMU project costs,[246] that it was difficult to segregate these costs once the SMU was underway,[247] and that they interpreted the plain language of D.15-07-008 differently.[248] The first two reasons do not excuse PG&E's failure to comply with D.15-07-008, which we note was not ambiguous in either its phrasing or its explanation for requiring PG&E to update its <u>incremental</u> SMU analysis.

At the conclusion of hearings, PG&E committed to providing an additional late-filed exhibit with calculations of the incremental SMU costs that would be in compliance with D.15-07-008. On October 17, 2016 PG&E served Exhibit PG&E-45, "Late Filed Exhibit on SmartMeter Upgrade Cost Effectiveness Update." PG&E states that Exhibit PG&E-45 provides the following information:

- An incremental analysis of Table 3 on page 152 of Decision D.09-03-026, estimating the portion of incurred costs associated with each element of the adopted incremental cost forecast.
- An annual break-out of the $202.3 million reduction in the PVRR for the total costs of the SmartMeter Program

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246 Exhibit PG&E-16 at 5.

247 RT at 996-999.

248 *Id.* at 999-1005.

referenced on Table 1-1 of Exhibit PG&E-16, to attribute those reductions, on an annual basis, to the net of (1) "incremental costs with timing delay" (which PG&E does not define); (2) reduced PTR program costs; and (3) impact of tax profiles, which PG&E explains is mostly due to accelerated tax depreciation provisions ("bonus" depreciation) extended by Congress over the SmartMeter Program deployment period.

- Recalculation of the time-of-use benefits in Exhibit PG&E-16, using current price forecasts through 2030.
- An update of the tax benefit calculations in Exhibit PG&E-16, after determining if the then-contemplated federal and state tax rules were formally adopted.

At first glance, the revised analysis provided by PG&E in Exhibit PG&E-45 is encouraging: PG&E now estimates incremental SMU project costs of just $661 million (Exhibit PG&E-45, Table 45-2), compared to incremental benefits of $786 million (Exhibit PG&E-16, Table 1-2).

Unfortunately, just as it did in preparing Exhibit PG&E-16, PG&E has again selectively updated certain values in its cost-benefit analysis in a manner that appears intended to preserve a cost-effective outcome for the SMU program by providing updated information when it favors that outcome, while failing to update information that could, presumably, tip the calculation into the negative.

It is not problematic for PG&E to provide newly forecast benefits for its anticipated implementation of TOU rates for residential and small/medium commercial customers: these programs were indeed not anticipated in their present form at the time the Commission issued D.09-03-026. The same is true of the projected additional tax benefits, and the extended bonus depreciation tax policies now reflected in PG&E's reduced cost estimates. However, PG&E has still not updated its originally estimated benefits for "energy conservation with HAN devices" or for air conditioning (A/C) cycling, and this appears to be a significant oversight on PG&E's part. Again, in D.15-07-008 the Commission directed PG&E to "prepare this analysis by updating Table 3 and Table 4 from D.09-03-026, adding line items as necessary…." PG&E did in fact add line items to Table 4 for newly identified benefits related to "energy conservation and demand response," but did not update the HAN-related conservation benefit or the A/C cycling benefit. PG&E cannot selectively decide what to update, and what not to update in response to the Commission's directive. To be clear, the underlying premise of the SMU was that it would "create a foundation for building an infrastructure that will enable and empower new ways of looking at energy use"; in addition to the PTR program, PG&E represented in A.07-12-009 that the SMU would enable expanded HAN-related benefits and A/C cycling. Based on the partially updated analysis that PG&E has presented in this proceeding, we cannot determine whether PG&E actually offered the latter two functionalities to its customers or, if so, whether they were offered and adopted on the scale and pace that PG&E used as the basis for estimating those forecast benefits.

First, at the time the Commission approved the SMU in D.09-03-026 PG&E intended to include an active "Home Area Network" radio in the new SmartMeters, in order to enable two-way communications directly into a customer's home, giving customers near real-time access to their energy usage data.[249] As noted above, in approving PG&E's SMU application, the Commission

[249] D.09-03-029 at 9. "PG&E envisions this technology will enable it to send time and price indicators to the customer's meter, giving the customer the opportunity to participate in demand response, time of use (TOU), and other energy management initiatives."

adopted an adjusted estimate of the incremental benefits from energy conservation with HAN devices equal to $269 million. The methodology that PG&E used to estimate these benefits is summarized in D.09-03-026. PG&E estimated conservation benefits starting in 2012 using the following assumptions:

- A technology adoption curve adapted from historic cell phone annual adoption rates;
- Technology adoption rates begin at 2% in 2012, top out at 30% in 2024, and remain flat until 2030;
- An average of 6.5% energy conservation for both electricity and natural gas annually for a customer with an in-home display device;
- Average usage per customer is based on PG&E's share of the CEC's 2008-2018 demand forecast;
- Energy forecasts for 2019 through 2030 are extrapolated from the average annual growth rate in the 2008-2018 forecast; and
- PG&E's share of the CEC demand forecast is estimated based on PG&E's 2006 FERC Forms 1 (electric) and 2 (natural gas) sales as a percent of the CEC's area recorded 2006 sales.

We are concerned that, once it received approval for its SMU investment, PG&E chose not to implement the HAN deployment in a manner consistent with the assumptions listed above (we note that in D.09-03-026 the Commission declined to attribute any benefits to natural gas conservation). For example, in 2013, the Commission approved PG&E's revised SmartMeter Home Area Network Implementation Plan, filed by PG&E in Advice Letter 3959-E-A in compliance with D.11-07-056.[250] PG&E was required to revise its original plan

[250] D.11-07-056, "Decision Adopting Rules to Protect the Privacy and Security of the Electricity Usage Data of the Customers of Pacific Gas and Electric Company, Southern California Edison

Footnote continued on next page

after the Commission found that none of the plans originally filed by the utilities were in compliance with D.11-07-056.[251] In its revised Implementation Plan, PG&E proposed a three-phase implementation schedule based on increasing levels of customer activation requests. Our review of Exhibits PG&E-16 and PG&E-45 in this proceeding indicates that PG&E did not update those SMU benefit calculations adopted by the Commission in A.07-12-009 to reflect the realities of the subsequent implementation plan that it filed in R.08-12-009. Nor did PG&E update the underlying assumptions regarding customer usage, conservation estimates, or, importantly, the avoided cost of energy or capacity (PG&E did update the same energy costs where they were used in its newly-provided TOU benefits calculation because it was specifically directed to do so at the conclusion of hearings; that update lowered the estimated benefits because the updated avoided energy costs were considerably lower than the costs reflected in the 2009 benefits calculations). Thus, we are left to consider incremental TOU benefits based on current price forecasts, but incremental HAN-related benefits using price forecasts from 2009 or even earlier. This yields inconsistent results that have little value to us.

Company, and San Diego Gas & Electric Company" in R.08-12-009, "Order Instituting Rulemaking to Consider Smart Grid Technologies Pursuant to Federal Legislation and on the Commission's own Motion to Actively Guide Policy in California's Development of a Smart Grid System."

[251] Commission Resolution E-4527, Finding 8: "In Ordering Paragraph 11 of D.11-07-056, the CPUC reiterated its requirements to have the Utilities demonstrate tangible progress toward its HAN-related objectives by requiring the Utilities to submit detailed plans for, among other elements, 1) actually initiating the HAN deployment, 2) making HAN functionality and benefits generally accessible to customers on a consistent, statewide basis, and 3) enabling a third party market to allow customers to utilize HAN devices of their choice."

The record in this proceeding shed no light on PG&E's reasoning regarding its decision to leave the estimated HAN-related benefits unchanged when it prepared Exhibit PG&E-16, even as it provided other, newly identified, benefit estimates. Our concern here is whether PG&E intentionally omitted information that would reduce its benefits estimates, and this is reinforced by our observation that PG&E has now twice failed to provide an accurate answer to the question we posed in D.15-07-008: whether the SMU program remained cost-effective.

PG&E's reluctance to comply with that D.15-07-008 only heightens our interest in obtaining an accurate answer to this question. However, we make an important distinction here. In D.09-03-026, we rejected recommendations to hold PG&E accountable for the benefits that it estimated in its application (as subsequently modified by the Commission), denying a request by TURN to penalize PG&E if it failed to achieve forecasted demand response benefits from both the original PG&E AMI decision and the SMU decision. Similarly, in our decision in SCE's AMI proceeding, we stated that "it is not reasonable to penalize SCE for failing to meet the forecasts made in the business case."[252]

We are not acting inconsistently with those decisions here. Rather, in A.10-02-028 we were faced with a request by PG&E that it be relieved from the obligation to take action that would deliver promised SMU benefits: PG&E was essentially altering the terms of the original SMU bargain, in its favor, because it had been authorized to proceed with a significant investment that would reduce

[252] D.08-09-039 at 53.

its operating costs, only to subsequently request cancellation of a program that was forecast to provide considerable benefits to ratepayers that would help the investment pay for itself. We are concerned that the situation with the HAN deployment is similar: once PG&E received authority to proceed with the SMU project investments, it did not to deliver on its commitment to enable the HAN-enabled energy conservation benefits. Together, the PTR benefit and the HAN-related benefits assumed by the Commission in D.09-03-026 totaled $615 million, almost 80% of the total forecast SMU benefits. Just as with PTR, when PG&E changes the terms of the bargain, we have a responsibility to ensure that PG&E's SmartMeter program is cost-effective and to assure PG&E's ratepayers that the SMU was a worthwhile investment of ratepayer funds.

For these reasons, we find that PG&E has not yet complied with Ordering Paragraph 5 of D.15-07-008. PG&E has not provided a <u>fully</u> updated analysis of the cost-effectiveness of its SMU project without the previously-expected benefits of a PTR program, because it did not prepare an analysis by <u>fully</u> updating Table 3 and Table 4 from Decision 09-03-026. This proceeding shall remain open so that PG&E can complete this compliance item. By "fully update" we mean that PG&E should provide revised values for every line item in the original tables, with full support in workpapers for each revised value. If a line item is added to either table, PG&E shall provide full workpapers for that as well. As part of the analysis, PG&E shall provide a narrative document that explains and justifies the revisions to each line item, or the reason for leaving a line item unchanged, or the reason for adding a line item. PG&E shall serve the updated analysis on the service list in this proceeding no later than 60 days after today's date. The assigned Commissioner and assigned ALJ shall determine further procedural steps upon receipt of PG&E's updated analysis.

6. Comments on Alternate Proposed Decision

The alternate proposed decision (APD) of the assigned Commissioner Picker 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. Comments were filed on April 24, 2017 by Settling Parties and CAUSE (Settling Parties state that CAUSE did not join their comments). No reply comments were filed.

Comments on the APD addressed the Rule 20A provisions in the APD, the RRRMA provisions in the APD, and the tax memorandum account described in the APD. These matters are addressed below.

In addition, this section addresses certain aspects of the comments on the PD of the assigned ALJ where the language in the APD is identical to that of the PD. Comments on the PD were filed on March 20, 2017 by PG&E, TURN, ORA, CFC, A4NR, Settling Parties (A4NR and CAUSE were parties to the Settlement Agreement, but did not join in these comments), PG&E and ORA (jointly) and EDF, CUE and PG&E (jointly). CAUSE filed opening comments one day late on March 20, 2017; the late filing was authorized by the assigned ALJ. The City of Hayward filed opening comments 8 days late; the late filing was authorized by the assigned ALJ. Reply comments were filed on March 27, 2017 by PG&E, TURN, CFC, A4NR and CAUSE.

A number of comments and reply comments on the PD addressed (1) the Commission's standard for review of settlements, (2) Rule 20A, (3) the RRRMA, (4) the tax memorandum account, (5) proposals for a third test year, and (6) the NERBA. These matters are addressed below. PG&E also made a number of requests related to the implementation of the Commission's decision, and some parties offered specific comments that fall outside the matters listed above. Each of these specific items is also addressed below.

Pursuant to Rule 14.3 (b), comments shall include a subject index listing the recommended changes to the proposed or alternate decision, a table of authorities and an appendix setting forth proposed findings of fact and conclusions of law.

Pursuant to Rule 14.3 (c), comments shall focus on factual, legal or technical errors in the proposed decision and in citing such errors shall make specific references to the record or applicable law. Comments which fail to do so will be accorded no weight. Comments proposing specific changes to the proposed or alternate decision shall include supporting findings of fact and conclusions of law.

Pursuant to Rule 14.3 (d), replies to comments shall be limited to identifying misrepresentations of law, fact or condition of the record contained in the comments of other parties. Replies shall not exceed five pages in length.

6.1. The Commission's Standard for Review of Settlements

Comments and reply comments regarding the manner in which the PD reviewed the Settlement Agreement were filed by Settling Parties, A4NR, CAUSE and PG&E. Because the APD reaches the same result as the PD, using identical language, we address those comments here.

Settling Parties address the Commission's standard for evaluating settlements, and the PD's application of that standard to the proposed settlement. Settling Parties assert that the PD's modifications to the Settlement Agreement are contrary to precedent and should be rejected.

A4NR states that the PD creates undue procedural and substantive ambiguities by misapplying the Commission's standard of review for comprehensive settlements in GRCs and thereby commits legal error. PG&E addresses A4NR's arguments in reply comments.

CAUSE states that the Commission should clarify the standards that it will use to evaluate settlements, especially those reached prior to a full evidentiary hearing, to articulate more clearly when modifications are appropriate.

As explained below, the comments and reply comments on the Commission's standard for review of settlements offer no compelling reasons to change the APD.

6.1.1. Settling Parties

Settling Parties describe their understanding of Commission precedent as "The Commission approves settlement agreements based on whether the settlement agreement is just and reasonable as a whole, not based on its individual terms." They support their statement by citing previous Commission statements, and assert that there is widespread precedent for this approach:[253]

> In assessing settlements we consider individual settlement provisions but, in light of strong public policy favoring settlements, we do not base our conclusion on whether any single provision is the optimal result. Rather, we determine whether the settlement as a whole produces a just and reasonable outcome.

Based on their understanding of previous Commission decisions, Settling Parties assert that the PD strays from this precedent. Settling Parties quote the

[253] Settling Parties cite D.10-04-033 at 9. Emphasis added by Settling Parties.

PD's description of its approach to reviewing the Settlement Agreement and state "it is not clear from the face of this discussion whether the PD intends to prescribe a new standard for evaluating settlements":[254]

> [W]e review the Settlement Agreement in the order in which it was presented. For each section, we provide Settling Parties' description of the issue, and address that issue. If we agree with the resolution, we state that the outcome is reasonable and should be adopted. In the event we disagree, or determine that additional discussion and clarification of a provision is needed, we provide that as necessary.

Settling Parties are mistaken if they interpret this text from the PD and the APD as prescribing a new standard for evaluating settlements. The Commission applied the approach described in the PD and the APD as recently as the Sempra GRC proceeding, which it addressed in D.16-06-054. That decision evaluated proposed settlements that resolved most of the issues in the GRC applications of SDG&E and SoCalGas. The Commission's decision includes a section entitled "Analysis Approach", wherein the Commission states:[255]

> In the sections which follow, we first provide an overview of how we have analyzed the revenue requirement requests of SDG&E and SoCalGas, and interim safety and accounting reports. This is then followed by an analysis of SDG&E's GRC application and the related settlements and other issues affecting SDG&E. This is then followed by an analysis of SoCalGas' GRC applications and the related settlements and other issues affecting SoCalGas.

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254 Settling Parties cite the PD at 34.

255 D.16-06-054 at 35.

The Commission goes on to explain its method:[256]

> To arrive at the overall revenue requirement, each of the pertinent line items on the summary of earnings table is discussed in the context of the testimony and the settlements on those topics.

The Commission further explains,[257]

> In each section, we describe the background of the particular costs that are being addressed. This is followed by a summary of the parties' positions, the applicable portions of the settlement agreements, and then a discussion of the costs and other issues.

Our approach to our analysis of the Settlement Agreement in this proceeding is no different than the approach we described in D.16-06-054. In that proceeding, as in this proceeding, PG&E, ORA, TURN, CforAT, CUE and EDF were parties, and all but PG&E and CforAT were signatories to the two settlement agreements reviewed by the Commission using the method described above. None of these parties took issue with the Commission's methodological approach to reviewing the settlement agreements in A.14-11-003 and A.14-11-004.

More importantly, Settling Parties have misinterpreted the precedent that they cite. The correct interpretation of the cited decisions is that the Commission does not reject an entire settlement in the event that it finds that specific components of that settlement fail to meet the standard required by Rule 12.1(d). Rather, as provided for in Rule 12.4, the Commission exercises the options

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[256] *Ibid.*

[257] *Id.* at 36.

available to it, to either hold hearings on the underlying issues, allow parties time to renegotiate the settlement, or propose alternative terms to the parties which are acceptable to the Commission. In fact, the Commission took this very approach in D.16-06-054, rejecting specific sections of the settlements in that proceeding, and providing settling parties the option of filing of a "Notice to Accept" the outcome adopted by the Commission, or filing a "Motion Requesting Other Relief."[258] The PD and the APD here took an identical approach.

The Settling Parties state that they "do not intend to suggest that the PD was wrong to carefully evaluate the individual substantive provisions of the Settlement Agreement", but then object that the careful evaluation undertaken in the PD concludes that four individual substantive provisions should not be approved. Without citation to the PD, Settling Parties assert that "in three substantive areas – Rule 20A, RRRMA costs, and taxes – the PD appears to seek an 'optimal' result in these individual areas instead of evaluating the provisions in light of the settlement as a whole."

The PD does not find the rejected provisions to be less than "optimal" nor does it reject those provisions on that basis. Rather, these provisions are rejected because they are found, individually, to be either not reasonable in light of the whole record, not consistent with law, or not in the public interest, and thus contrary to Rule 12.1(d). It is simply illogical for Settling Parties to suggest to the Commission that it should carefully evaluate the individual substantive

[258] D.16-06-054, Ordering Paragraphs 14 and 15.

provisions of the Settlement Agreement, but if it finds specific items to be either not reasonable in light of the whole record, not consistent with law, or not in the public interest, it should approve them anyway because the Settlement Agreement as a whole is acceptable to the Commission. By that standard, the Commission should never reject any specific aspect of a Settlement, no matter how egregious, if the remainder of the Settlement was acceptable to the Commission. Such an approach would reduce the Commission to a bystander in its own proceedings.

6.1.2. A4NR

A4NR states that the PD creates undue procedural and substantive ambiguities by misapplying the Commission's standard of review for comprehensive settlements in GRCs and thereby commits legal error.

A4NR "submits that the Commission's rules and prior precedents describing the standard of review to be applied to settlements weigh in favor of approving the Settlement Agreement in its entirety and without the revised provisions proffered in the Proposed Decision" even if the provisions in the PD are "superior" to those in the Settlement Agreement, and would bring the Settlement Agreement "into greater conformity with the record, the law and/or the public interest."[259] Like the Settling Parties, A4NR also misinterprets the Commission's standard of review, and thereby fails to establish that the PD commits legal error.

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259 A4NR Opening Comments at 3.

As explained above, the PD and the APD did not reject the individual provisions in the Settlement Agreement because they were "inferior" to the PD: each provision was rejected because it did not meet the test required by Rule 12.1(d). The PD and the APD did not apply a "superior/inferior" test, or an "optimality" test. Rather, the PD and the APD applied the plain language of Rule 12.1(d) to these particular provisions of the Settlement Agreement, and on that basis alone, found each of them to be in violation of that standard.

A4NR relies on a misreading of the Rule 12.1(d) standard to suggest that "in complex, multi-faceted proceedings such as GRCs, where comprehensive settlements have addressed myriad issues, many of which do not bear direct relationships to one another, the Commission has applied this standard of review as to 'the whole of a settlement' rather than to the individual provisions of a settlement," A4NR compounds this misreading by quoting earlier Commission decisions out of context. For example, A4NR cites D.07-03-044 in PG&E's test year 2007 GRC, where the Commission approved a settlement that was contested by a number of parties. There, the Commission reviewed "the Settlement's resolution of every contested issue, with careful consideration given to each issue raised by" the contesting parties, stating "[t]he purpose of our issue-by-issue review is not to second guess the Settlement outcome for every individual issue, but to assess whether the Settlement as a whole is reasonable in light of the entire record, consistent with applicable law, and in the public interest." After reviewing <u>each issue</u>, especially the contested issues, the Commission found that the <u>specific settled outcome for that issue</u> was "reasonable in light of the record, consistent with applicable law, and in the public interest." A4NR would surely agree that the Commission would not have made the effort to review each and every contested issue unless it was open to the arguments of the contesting parties. The PD and the APD here take the same approach to the Settlement Agreement in this proceeding, reviewing each and every issue to determine whether the settled outcome is "reasonable in light of the record, consistent with applicable law, and in the public interest." The only difference from D.07-03-044 is that for several discrete issues, the PD and the APD could not reach that conclusion. A4NR has not demonstrated legal error.

A4NR also finds procedural ambiguity in the PD's statement that "this proceeding shall remain open until a decision or ruling" resolves any motion requesting relief that is filed, should that occur instead of a Notice to Accept PG&E's Adopted Test Year 2016 Revenue Requirement. The APD has been clarified to indicate that such a motion may only address the items in the Settlement Agreement that were rejected by the APD. The remainder of the APD is not subject to reconsideration.[260]

6.1.3. CAUSE

In comments on the PD, CAUSE agrees with the other settling parties that the Commission should not evaluate reasonableness issue by issue. However, CAUSE also argues that the Commission should modify any single provision that, as proposed, contravenes the public interest, "ideally doing so with any adjustments necessary to preserve the fundamental bargain that the parties

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[260] PG&E, in its March 29, 2017 Reply Comments, objects to this suggestion by A4NR. As we explained above, we agree with the PD's rejection of four specific items in the Settlement Agreement, its ultimate resolution of each item, and its procedural approach to allowing parties to either assent to that resolution, or seek other relief regarding those four items. The PD approved the remainder of the Settlement Agreement, and we will not entertain motions that seek to disturb that outcome.

sought."[261] We have explained above why we disagree with CAUSE's first point. CAUSE also supports modification of single provisions, as the PD and the APD have done, but in a manner that preserves the "fundamental bargain" of the settlement. Given that Rule 12.6 protects the confidentiality of settlement negotiations, and the attendant reluctance of settling parties to divulge any details that underlie the "fundamental bargain" in settlements, we find CAUSE's suggestion in this regard impractical and inconsistent with our Rules.

6.2. Comments on Rule 20A Issues in the APD

Comments on the APD regarding Rule 20A were filed by Settling Parties and CAUSE. Settling Parties agree that the APD's resolution of the Rule 20A issue is reasonable in light of the record, consistent with law and in the public interest. CAUSE includes extensive comments on Rule 20A matters that rely on material outside the evidentiary record in this proceeding. As noted above, Rule 14.3 (c), requires that comments shall focus on factual, legal or technical errors in the proposed decision and in citing such errors shall make specific references to the record or applicable law. Comments which fail to do so will be accorded no weight. Much of CAUSE's comments fail to make specific references to the record, and for this reason we accord them no weight.

6.3. Residential Rate Reform Memorandum Account

In their comments on the APD, Settling Parties propose a revised version of Section 3.1.5.2 of the August 3, 2016 Settlement Agreement in order to address the "considerations" raised in the APD and PD (both the PD and the APD

[261] CAUSE Opening Comments at 5.

rejected Section 3.1.5.2 of the Settlement Agreement). Under the revised approach, the costs will be reviewed via an application or through the existing rulemaking on residential rate reform in a manner subject to the same procedural considerations of a new application. The revised approach also provides that review by the Commission will only take place after the costs are incurred. For these reasons, Settling Parties assert that the revised Section 3.1.5.2 of the Settlement Agreement is reasonable in light of the record, consistent with law and in the public interest.

We have reviewed the revised Section 3.1.5.2 of the Settlement Agreement and find that it addresses the concerns identified in the PD and the APD. Therefore, it should be adopted. The APD has been revised accordingly.

6.4. Tax Reform Memorandum Account

In comments on the PD, PG&E recommends that the Settlement Agreement's original terms concerning the tax memorandum account should be adopted, instead of the version adopted in the PD. The APD adopts the same version as the PD, using identical language. As explained below, we have considered each of PG&E's arguments, and conclude that no changes to the APD are warranted with respect to the tax memorandum account.

PG&E's two arguments are interrelated, so we address them together. First, PG&E argues that Commission precedent argues against, not for, the APD's new memorandum account. Second, PG&E argues that the APD's proposed memorandum account is not an established precedent and is not a sufficient basis to reject the Settlement Agreement. PG&E cites a 1984 Commission decision in Order Instituting Investigation (OII) 24 and suggests that the Commission should rely on that decision for precedent, not the two decisions cited in the APD which the Commission issued just 5 months ago (D.16-12-024) and 11 months ago (D.16-06-054).[262]

PG&E's arguments rely on an incomplete reading of D.84-05-036 to oppose an outcome that is not, in fact, part of the APD. The Commission begins D.84-05-036 with an explanation that "[i]n the order that instituted this investigation we stated "the determination of reasonable allowable ratemaking expenses for federal and state income taxes is a matter of continuing concern to this Commission in its effort to establish reasonable utility rates."[263] The Commission then addresses a number of specific questions with respect to taxes and appropriate ratemaking policies. PG&E cites D.84-05-036 and asserts that "[t]he Commission acknowledged that differences between estimated and recorded tax deductions and correspondingly estimated and recorded tax expense will occur in the ratemaking process and concluded that a true-up mechanism for taxes is not good policy." While the Commission does decline to "require utilities to submit adjustments reflecting reductions in taxes," it qualifies this result by stating "[w]e agree that changes in tax laws may be taken into account in ratemaking." The APD does not adopt any sort of "true-up mechanism"—rather, it adopts a mechanism that will provide the Commission with the information that it needs so that "changes in tax laws may be taken into account in ratemaking." PG&E appears concerned that the APD adopts what

[262] *See*, D.84-05-036. OII 24 was an "Investigation On The Commission's Own Motion Into The Method To Be Utilized By The Commission To Establish The Proper Level Of Income Tax Expense For Ratemaking Purposes Of Public Utilities And Other Regulated Entities."

[263] 15 CPUC2d 42.

PG&E terms an "actual taxes" standard, stating "[i]n light of the widely recognized problems inherent in an actual taxes standard, it would be expected that a change in policy be preceded by a well-articulated explanation; however, the APD makes no reference to OII 24, let alone an attempt to rationalize the APD's outcome against the instruction in OII 24."[264] Again, the APD makes no such change in policy.

PG&E goes on to argue that the tax memorandum account established by the Commission in D.16-06-054 and D.16-12-024 is "not strong precedent," having "not been properly tested." PG&E further asserts that there is no evidence in the record that PG&E's tax circumstances are similar to those other utilities cited by the APD and that absent such evidence, "it cannot be fairly said that the same measures imposed on those utilities should apply here."[265] We disagree that the APD is "imposing measures" on PG&E, as if requiring PG&E to establish the specified memorandum account is a form of punishment. It is not, nor was it intended to "punish" the Sempra utilities or Liberty. Rather, as clearly stated in D.16-06-054 and D.16-12-024, a tax memorandum account will simply "increase the transparency of the utilities' incurred and forecasted income tax expenses to the Commission" and "provide the Commission with information to review in order to evaluate the reasonableness of various tax options."[266] PG&E should not object to the Commission seeking such information, rather than

[264] PG&E Comments at 10.

[265] *Ibid.*

[266] D.16-12-024, Finding of Fact 15.

leaving it to parties to raise such issues once every three years in GRC proceedings.

Finally, in its third argument against the APD, PG&E asserts that the APD's proposed memorandum account needs to be reconciled with the policies described in OII 24. PG&E provides several examples of specific tax treatment and suggests that the language describing the adopted memorandum account would benefit from clarification: "This is not intended to be an all-inclusive list, but rather to illustrate, as the Commission recognized in OII 24, that an evaluation of 'actual taxes' can be confusing and potentially misleading." PG&E's detailed questions are good examples of our reasons for seeking more transparency and information with regard to the complexities of utility tax policy, and we remain confident that the memorandum account adopted in the PD, D.16-06-054 and D.16-12-024 is the best means of accomplishing our goal. We leave the APD unchanged with respect to the adopted tax memorandum account.[267]

Settling Parties also addressed the tax memorandum account in their comments on the APD. Settling Parties, "without necessarily agreeing on the merits of PG&E's concerns," recommend deletion of the provision in the APD requiring that the memorandum account have a separate line item detailing the differences between tax expenses forecasted and tax expenses incurred, specifically resulting from "net revenue changes." With no explanation, Settling Parties state that they "have concluded that the removal of item (1) concerning

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[267] We have clarified the language in the PD to indicate that the adopted memorandum account is "identical" to the account adopted in D.16-06-054 and D.16-12-024, rather than "similar."

'net revenue changes' would reasonably address PG&E's concerns while still achieving the Commission's stated objectives."[268] Settling Parties further state their belief, again with no explanation, that "this approach is reasonable in light of the record, consistent with law and in the public interest."[269]

Because Settling Parties offer no substantive basis for changing the APD's treatment of the tax memorandum account, we leave the APD unchanged.

6.5. Contested Items

6.5.1. Third Test Year

The APD reaches the same result as the PD, using identical language, regarding proposals for a third test year, so comments on the PD are considered here. ORA and PG&E (jointly) recommend that the PD should be revised to state that, if the Commission adopts a four-year cycle prior to PG&E filing its next GRC application, then (i) the amount for the third post-test year recommended by ORA and PG&E in this matter should be adopted and (ii) PG&E would be required to file its next GRC for a 2021 test year.

In reply comments, TURN opposes this modification, noting that PG&E can seek appropriate procedural relief in the future, in the event that the Commission adopts a four-year GRC cycle. TURN also supports A4NR's reply comments, where A4NR states that the evidentiary record does not supporting findings of fact that ORA's proposed 2020 annual revenue requirement is just and reasonable.

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[268] April 24, 2017 Opening Comments of Settling Parties on the APD of Commissioner Picker at 6.

[269] *Ibid.*

We decline to modify the APD as recommended by ORA and PG&E. TURN's procedural arguments are correct, and A4NR is correct that we have no evidentiary support to adopt the changes requested by ORA and PG&E.

6.5.2. New Environmental Regulatory Balancing Account

The APD reaches the same result as the PD, using identical language, regarding proposals for a 6.5.2. New Environmental Regulatory Balancing Account, so comments on the PD are considered here. CUE, PG&E and EDF (jointly) recommend that the PD should be revised to approve the New Environmental Regulatory Balancing Account proposed in Section 4.2 of the Settlement Agreement, arguing that it remains uncertain whether the Gas Leak OIR will address cost recovery because a ruling on the matter is still pending. This is insufficient reason to address this matter here, and we leave the APD unchanged.

6.6. Other Changes to the PD Proposed by PG&E

In addition to its proposed revisions to the PD regarding the Settlement Agreement, PG&E proposes several other modifications related to how it will implement the Commission's decision. Because these proposals are applicable to the APD as well, we consider them here.

First, PG&E requests that the PD be revised in order to accommodate a delay in implementation of the rate change in order to stabilize rates for customers. Instead of implementing tariff changes within 30 days of the effective date of the decision, as directed by the PD, PG&E seeks flexibility in implementing the GRC rate changes for "rate smoothing purposes." PG&E reports that the net revenue requirement changes from this GRC decision are now expected to result in a decrease of more than $100 million, for reasons having to do with "electric revenue requirement and related rate changes that occurred on January 1, 2017, that were originally expected to go into effect with the implementation of 2017 GRC rates, as well as the need to true up various balancing and memorandum accounts."[270] PG&E also notes anticipated future rate increases associated with other filings pending at the Commission for which decisions are expected later this year or no later than January 1, 2018 and suggests smoothing customer rates by avoiding lowering rates now only to increase them later. PG&E suggests using the expected decrease noted above to offset the anticipated future rate increases. PG&E states that this would be consistent with past practice in working with the Energy Division, where PG&E has undertaken efforts to manage the timing of revenue changes and subsequent rate changes. We have made this change to the APD.

Second, PG&E requests that the Commission adopt its suggested ratemaking treatment for costs associated with the Federal monitor imposed as part of its criminal case sentencing. As directed by the PD, PG&E included in its comments "a statement that explains its proposed ratemaking treatment for the costs that it will incur in connection with the monitorship" imposed by the United States District Court, Northern District of California, San Francisco Division, in the recent criminal matter. PG&E states that its shareholders will cover the direct costs of the monitorship:[271]

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[270] PG&E Comments at 12.

[271] *Id.* at 13.

> This shall include all amounts paid to the monitor or persons hired by the monitor pursuant to the monitor's authority. These costs shall include fees, transportation, meals and incidental expenses.
>
> PG&E's shareholders will also cover the expenses of the group being formed at PG&E that will be dedicated to assist with the work of the monitor and address the monitor's needs. At present, PG&E expects to dedicate a team of three full time employees for this purpose. This group will report to PG&E's Senior Vice President and Chief Ethics and Compliance Officer. PG&E shareholders would also cover the costs of any incremental resources hired elsewhere at PG&E that would be dedicated to assisting with the work of the monitor or addressing the monitor's needs.
>
> PG&E will record the above-described expenses to FERC account 426.5 (below the line expenses). Thus, these expenses will not be considered when forecasting expenses in future rate cases.

PG&E does note that "the activities of the monitor will likely impact, to varying degrees, the work of scores of employees across the organization.… PG&E does not expect the work of those impacted by the activities of the monitor in the course of their regular jobs… to be covered by shareholders."

Finally, PG&E notes that "it is also possible that the monitor may recommend operational changes or improvements that affect future costs. PG&E expects that such costs would be evaluated as would other similar costs in future ratemaking proceedings."

We decline PG&E's request that we "adopt" its suggested ratemaking treatment for these costs. Our purpose in seeking this information was to clarify and document PG&E's intentions in this matter, and we appreciate PG&E's response. We will review PG&E's actions in subsequent proceedings.

Third and finally, PG&E proposes to submit its comparison of 2017 budget and imputed regulatory values within 60 days of today's decision. This is a reasonable deadline and we approve it.

6.7. Other Changes to the PD Proposed by Other Parties

6.7.1. TURN

TURN recommends modification of the PD in three areas. Because these proposals are applicable to identical language in the APD, we consider them here.

First, TURN recommends that the PD should be modified to remove "confusing and inappropriate dicta" regarding post-test year ratemaking (PTYR). The PD's discussion of the PTYR expressed some concern with the lack of record and went on to approve the PTYR aspects of the settlement based on the Commission's own review of that record, including PG&E's own Post-Test Year forecasts.

According to TURN,[272]

- The PD risks creating confusion about whether the Commission intends to fundamentally alter the way it approaches PTYR, an outcome that would be unfair to the parties in this proceeding.
- The PD also errs in relying on PG&E's unexamined Post-Test Year capital spending forecasts to assess the merits of the Settlement Agreement PTYR adjustments.

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[272] TURN Opening Comments at 5.

- The PD overreaches in apparently reaching the merits of PTYR methodologies, an issue not addressed by the Settlement Agreement.

Each of TURN's assertions is incorrect. We address them here at some length.

As a threshold matter, we note that TURN raises issues with the PD that it cannot substantiate. TURN's characterization of the PD's discussion of PTYR is rife with qualifiers such as "apparently," "seems to," "insinuating," "appears to suggest," "seems to blur," "as suggested by," "unfair and inappropriate to suggest," "apparently embracing," "gives the appearance of," "apparent reliance on," "the appearance of prejudging," and "can be read as." The alterations to the PD suggested by TURN based on its speculative analysis are inappropriate. We make no substantive changes to the PD in response to TURN's unsupported allegations, but we do take this opportunity to explain the PD's analysis of the PTYR.

With respect to TURN's first recommendation, we note that nowhere in the PD does the Commission state an intention to "fundamentally alter the way it approaches PTYR." Contrary to TURN's somewhat surprising assertion that "[n]othing in the Scoping Memo can be fairly read as an indicator that the Commission intended to change its longstanding and recently-affirmed approach to establishing PTY revenue requirements"[273] the assigned Commissioner indicated in the Scoping Memo that the scope of this proceeding included whether "the proposed attrition adjustments for 2018 and 2019 for the

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[273] *Id.* at 7.

electric and gas distribution and electric generation functions should be approved." The Commission need not specify its method of analysis beforehand, in the scoping memo or elsewhere. Rather, it relies on the record of the proceeding, as that record unfolds, to inform its analysis. It then makes its decision based on that record, as the PD has done here. This analysis is required by law.[274] The PD explained why it found the record developed by parties inadequate, and the PD explained the further steps taken to reach a decision on the PTYR settled-upon amounts. Those steps were consistent with the precedent cited by TURN, which all describe prior Commissions confronting the challenge of how to best evaluate and approve GRC revenue requirements for attrition years. The approach taken in the PD and the APD is entirely consistent with that precedent. It relied in part on budget-based information to evaluate and approve PTYR amounts that ORA developed using an escalation-based methodology.

With respect to TURN's second recommendation, TURN is incorrect in its assertion that "the PD also errs in relying on PG&E's unexamined PTY capital spending forecasts to assess the merits of the Settlement Agreement PTYR adjustments." TURN objects that "the PD looks to PG&E's forecasts, despite acknowledging that they have generally not been reviewed by intervenors." In fact, as the PD explains, the PD examines PG&E's forecasts because these forecasts were not reviewed by the intervenors. As the PD explained at the outset of its discussion of the Test Year and Post-Test Year revenue requirements, the Commission is obligated to explain to PG&E's ratepayers why it is approving

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[274] Pub. Util. Code § 1701.1(e)(8): "The commission shall render its decisions based on the law and on the evidence in the record."

PG&E's revenue requirements: not just for the test year, but for all three years of the GRC period.[275] If the intervenors have not examined all three years, whatever their reasons for not doing so might be, it is left for the Commission to conduct the examination that is required by statute and the Commission's rules. The PD did not approve "unexamined" PTYR forecasts: those forecasts were examined by Commission staff because the intervenors did not conduct this examination. This approach is not inconsistent with D.14-08-032, as TURN asserts. The 2014 Commission took one approach, consistent with precedent, while the PD takes a different approach, also consistent with precedent. It relied <u>in part</u> on budget-based information to approve PTYR amounts that ORA developed using an escalation-based methodology.

With respect to TURN's third recommendation, TURN is also incorrect in its (qualified) assertion that the PD overreaches in "apparently" reaching the merits of PTYR methodologies, an issue not addressed by the Settlement Agreement:

> <u>Last but not least</u>, the PD errs under the circumstances here in apparently embracing one PTYR methodology – a budget-based forecast methodology – over the various other methodologies previously relied on by the Commission [footnote omitted]. The issue of PTYR methodology, as opposed to revenue requirements, was not settled in this case, as explained above, and its resolution is unnecessary for the Commission to approve the Settlement Agreement [footnote omitted].[276]

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[275] PD at 124.

[276] TURN Comments at 9, emphasis in original.

The PD did not reach the merits of PTYR methodologies, nor can TURN cite such a statement in the PD, instead resorting to the qualifier "apparently." TURN again sees a result in the PD that does not exist. More importantly, while TURN is correct with reference to the PTYR methodology that "its resolution is unnecessary for the Commission to approve the Settlement Agreement," as explained above the Commission nevertheless cannot approve the Settlement Agreement without examining its recommendations regarding the PTYR, and in this proceeding that examination did require evaluating the results of PG&E's budget-based forecast methodology as well as the various other methodologies previously relied on by the Commission, and relied on here by intervenors such as TURN and ORA. As TURN surely knows, the actions of previous Commissions are not binding on the present Commission, and if this Commission finds it necessary to examine budget-based forecasts in order to reach a finding on the reasonableness of a Settlement Agreement to which TURN is a signatory, it will do so, and TURN has no real basis for objecting to the means found necessary by the Commission to reach its decision. The logic of TURN's argument is that because intervenors do not have the resources to examine the PTYR in great detail, the Commission should not do so either. For the reasons explained above, we disagree, and we have not modified the APD as requested by TURN.

TURN's second broad recommendation for modification of the PD concerns the discussion in the PD regarding deferred safety spending. TURN suggests deleting this discussion in order to avoid unintended and unnecessary controversy over its interpretation in the future. We agree with TURN's recommendation and have modified the APD by deleting the paragraph identified by TURN.

TURN's third broad recommendation for modification of the PD is to clarify that the Commission may require remedial action, consistent with General Order 96-B, General Rule 7.5.3, if PG&E does not satisfy the Commission's demand for "positive proof" that the authorized test year revenue requirement is still reasonable, despite PG&E's recently announced spending reductions. TURN recommends adding language to the PD to clarify that the Commission may require PG&E to commence remedial action should Staff reject PG&E's Tier 1 advice letter because PG&E's "positive proof" is insufficient. TURN's comments and recommendations are well-taken, and we have modified the APD accordingly.

6.7.2. CAUSE

The opening and reply comments on the PD, as well as the opening comments on the APD, filed by CAUSE are procedurally improper for a number of reasons. Because CAUSE includes arguments in those comments in support of its future request for intervenor compensation, we discuss these improprieties here in order to assist the Commission when it evaluates any claim submitted by CAUSE.

In its opening comments on the PD, CAUSE includes significant material barred by Rule 14.3(c), which requires that comments shall focus on factual, legal or technical errors in the proposed decision and in citing such errors shall make specific references to the record or applicable law:

- Section II of CAUSE's opening comments is entitled "The Integrity of this Settlement and Future Proceedings Requires that CAUSE Receive a Reasonable Award of Intervenor

Compensation". This section cites no factual, legal or technical errors in the proposed decision and will be accorded no weight.[277]

- In Section III and Section IV of its opening comments, CAUSE takes positions contrary to the Settlement Agreement to which it is a signatory.[278] In reply comments, PG&E objects that CAUSE "inappropriately re-argues issues settled by the Settlement Agreement executed by CAUSE."[279] Pursuant to Rule 14.3 (c), these sections of CAUSE's opening comments will be accorded no weight.
- As noted earlier, Section VI of CAUSE's opening comments also advocate for a result contrary to the Settlement Agreement and will be accorded no weight.
- Finally, portions of Section IX also appear to advocate for a result that is inconsistent with the Settlement Agreement, and those portions will be accorded no weight.

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[277] In its reply comments, CAUSE cites Conclusions of Law 22 and 23 of the PD and suggests that these provisions are intended to deny CAUSE eligibility for intervenor compensation ("Any outstanding motions or requests that have not been addressed in this decision or elsewhere are denied. All of the oral and written rulings that the assigned ALJ has issued in this proceeding are affirmed.") This is not credible argument. CAUSE's eligibility for intervenor compensation has its own long procedural history, and it is not proper for CAUSE to bring those matters into comments on the PD, nor to interpret the cited Conclusions of Law as an effort to deny eligibility without addressing CAUSE's filings.

[278] CAUSE opening comments, Section III ("The Commission Should Modify Any Provision of a Settlement that Offends State Law or the Public Interest") and Section IV ("Subsequent to CAUSE's Acceptance of the Proposed Settlement, the Conviction and Sentencing of PG&E Demonstrated that Maintenance of its Existing Compliance System is Contrary to the Public Interest").

[279] PG&E reply comments at 3: "Nonetheless, by the express terms of the Settlement Agreement: 'Unless otherwise provided in this Agreement, all proposals and recommendations by the Settling Parties…are either withdrawn…or considered subsumed without adoption by this Agreement.'"

In its reply comments on the PD, submitted after the 5:00 p.m. deadline on March 27, 2017, CAUSE includes material that replies to statements made by PG&E in its own reply comments, which PG&E filed and served earlier that day.[280] Pursuant to Rule 14.3(d), which requires that "replies to comments shall be limited to identifying misrepresentations of law, fact or condition of the record contained in the comments of other parties" the Commission has disregarded those portions of CAUSE's reply comments, specifically Section I and those portions of Section II that appear to be responding to PG&E's reply comments or that appear to be contrary to CAUSE's stated support for the Settlement Agreement.

In its opening comments on the APD, as noted earlier much of CAUSE's comments on Rule 20A matters fail to make specific references to the record, and for this reason we accord them no weight. CAUSE also included argument in its opening comments on the APD regarding the Commission's determination of eligibility for intervenor compensation. Consistent with our determination regarding CAUSE's inclusion of the same subject in its opening comments on the PD, this material again falls outside the parameters of Rule 14.3(c), and for that reason we accord this material no weight in this decision.

7. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Stephen C. Roscow is the assigned ALJ in this proceeding.

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[280] Pursuant to Rule 1.15 (Computation of Time) if an act occurs after 5:00 p.m., it is deemed as having been performed on the next day.

Findings of Fact

1. As described in this decision, the Commission has reviewed and considered all of the exhibits in this proceeding, the proposed settlement, and all of the arguments and issues that parties have raised in deciding what costs should be adopted.
2. The Commission is committed to the safety of utility operations, and the applicants are expected to make safety a foundational priority.
3. In authorizing the adopted revenue requirement for PG&E, the Commission has placed an emphasis on programs and activities that enhance the safety and reliability of its gas and electric infrastructure and operations.
4. The agreed-upon 2017 Gas Distribution expenses and capital expenditures are reasonable.
5. The agreed-upon 2017 Electric Distribution expenses and capital expenditures are reasonable.
6. The agreed-upon 2017 Energy Supply expenses and capital expenditures are reasonable.
7. The Commission's SED recommends that PG&E Energy Supply management should undertake additional communication and coordination with the California DOSD.
8. The agreed-upon 2017 Customer Care expenses and capital expenditures are reasonable, in light of the Settling Parties' April 24, 2017 proposed alternative provision for the RRRMA.
9. A tax memorandum account would increase the transparency of PG&E's incurred and forecasted income tax expenses to the Commission, so that the Commission can more closely examine revenue impacts caused by PG&E's

implementation of various tax laws, tax policies, tax accounting changes, or tax procedure changes.

10. On January 11, 2017 PG&E issued a news release announcing new, streamlined management structures and a series of efficiency measures that appear to be intended to reduce costs by approximately $300 million annually.

11. With respect to PG&E's January 11, 2017 announcement, it is not clear how much of PG&E's intended spending reductions are in budget categories that are funded by its GRC-related revenue requirement. PG&E's announcement raises the question of whether PG&E's intention to reduce 2017 spending by $300 million is based on a starting point equal to the revenue requirement authorized in this decision, or some other amount.

12. On August 9, 2016, a federal jury found PG&E guilty on five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act and one count of obstructing a federal agency proceeding. On January 26, 2017, the Court issued a judgment of conviction. The Court sentenced PG&E to a five-year corporate probation period, oversight by a third-party monitor, a fine of $3 million to be paid to the Federal government, certain advertising requirements, and community service.

13. PG&E has provided considerable detail on the metrics in the STIP, how they are developed and evaluated, and how safety affects the STIP.

14. In D.16-06-005 the Commission directed its Energy Division to conduct a workshop to explore moving toward a longer GRC cycle. The workshop took place on January 11, 2017 but the post-workshop report has not yet been completed or made available.

15. The Commission is developing a record on the question of whether a two-way balancing account should be established for interim cost recovery in

R.15-01-008, its Order Instituting Rulemaking to Adopt Rules and Procedures Governing Commission-Regulated Natural Gas Pipelines and Facilities to Reduce Natural Gas Leakage Consistent With Senate Bill 1371.

16. PG&E has not provided a fully updated analysis of the cost-effectiveness of its SMU project without the previously-expected benefits of a PTR program, because it did not prepare this analysis by fully updating Table 3 and Table 4 from D.09-03-026.

Conclusions of Law

1. The Commission's duty and obligation under Pub. Util. Code. § 451 is to establish just and reasonable rates to enable PG&E to provide safe and reliable service, while allowing PG&E the opportunity to earn a fair return on property that the company uses in providing its utility services.

2. Pursuant to Pub. Util. Code § 963(b)(3), in setting rates in this proceeding, the Commission takes all reasonable and appropriate actions to ensure as a top priority the safety of the public and gas corporation employees, consistent with the principle of just and reasonable cost-based rates.

3. In adopting the revenue requirements as set forth in Appendix A, and consistent with the obligations under Pub. Util. Code § 451 to establish just and reasonable rates, the Commission places priority on ensuring that PG&E will have ongoing resources in terms of infrastructure and operations to provide safe and reliable natural gas and electric power service.

4. The agreed-upon 2017 Gas Distribution expenses and capital expenditures should be adopted.

5. The agreed-upon 2017 Electric Distribution expenses and capital expenditures should be adopted.

6. PG&E should establish a Rule 20A balancing account that tracks the annual capital and expense costs for Rule 20A undergrounding projects, on a forecast and recorded basis, so that overcollected balances in the account remain available for future Rule 20A projects. The Commission shall review the balances in the account in PG&E's next GRC proceeding.

7. An audit of PG&E's Rule 20A program is necessary in order to ensure that PG&E has fully accounted for annual Rule 20A budgeted amounts, and to ensure that localities will receive the full benefit of these funds.

8. The agreed-upon 2017 Energy Supply expenses and capital expenditures should be adopted.

9. PG&E should work with DSOD and then develop a reporting schedule and format that will enable the Commission to monitor the progress and outcome of PG&E's discussions with DSOD regarding development of a structured risk portfolio management program to assess, rank, and effectively mitigate risks at its dams in a timely manner.

10. The provisions in Section 3.1.5.2 of the Settling Parties' April 24, 2017 proposed alternative regarding PG&E's RRRMA should be adopted because they are reasonable, in the public interest, and consistent with the law.

11. As described in the Settling Parties' proposed alternative provisions, PG&E should file a standalone application for recovery of costs recorded in its Residential Rates Reform Memorandum Account, or may seek recovery of those recorded costs in R.12-06-013.

12. PG&E should establish a two-way tax memorandum account to track any revenue differences resulting from the differences in the income tax expense forecasted in this proceeding, and the tax expenses incurred during the 2017-2019 GRC period.

13. PG&E's ongoing reporting activities, as reflected throughout the Settlement Agreement, should be implemented in a manner that best suits the Commission's need for information about how PG&E is implementing this decision.

14. With the inclusion of the Settling Parties' April 24, 2017 proposed alternative regarding PG&E's RRRMA, except for the Settling Parties' agreement with respect to a tax memorandum account, the Settlement Agreement attached to the Joint Settlement Motion is reasonable, in the public interest, and consistent with the law.

15. PG&E should demonstrate to the Commission that it will not collect in rates any funds rendered unnecessary by the $300 million in spending reductions that it announced on January 11, 2017 and the Commission should require PG&E to take remedial action if it fails to do so.

16. The Commission should determine whether or not PG&E intends to seek recovery in rates for the costs that it will incur in connection with the monitorship imposed by the court as part of its probation stemming from its August 9, 2016 criminal conviction in USA v. Pacific Gas and Electric Company.

17. It would be premature for the Commission to prejudge the outcome of the workshop process that considered a longer GRC cycle by deciding in this decision whether or not the term of this GRC should be three or four years.

18. The Commission should not decide in this GRC whether PG&E should be authorized to establish a new balancing account to record costs to comply with gas leak management requirements that may emerge from Commission Rulemaking R.15-01-008, because the same question is now actively pending in that proceeding.

19. PG&E has not complied with Ordering Paragraph 5 of D.15-07-008.

20. PG&E should prepare a complete update of Table 3 and Table 4 from D.09-03-026.

O R D E R

IT IS ORDERED that:

1. The August 3, 2016 joint motion for adoption of settlement agreement (Settlement Motion) regarding the Test Year 2017 General Rate Case (GRC) of Pacific Gas and Electric Company (PG&E), including attrition years 2018 and 2019 is granted, with the exceptions listed below. With these specified exceptions, the Settlement Agreement attached to the Settlement Motion is adopted.

    a. Section 3.1.5.2 of the Settlement Agreement, as reflected in the Settling Parties' April 24, 2017 proposed alternative provisions, is adopted. PG&E shall file a standalone application for recovery of recorded costs in its Residential Rates Reform Memorandum Account, or shall seek recovery in in Commission Rulemaking 12-06-013.

    b. Section 3.1.9.3 of the Settlement Agreement is not adopted. Instead, as described in Ordering Paragraph 11 below, PG&E shall file an advice letter to establish a two-way tax memorandum account.

Pursuant to Rule 12.4(c) of the Commission's Rules of Practice and Procedure, Settling Parties shall have 15 days from today's date to file with the Docket Office, and serve, a "Notice To Accept PG&E's Adopted Test Year 2017 Revenue Requirement," or to file a "Motion Requesting Other Relief."

2. In the event a "Motion Requesting Other Relief" is filed, parties may respond to the motion as provided for in Rule 11.1. The adopted Test Year 2017 revenue requirement for Pacific Gas and Electric Company shall remain in effect

until a decision resolving the request for other relief is adopted by the Commission.

3. Any filing made pursuant to Ordering Paragraphs 1 and 2 shall only address the provisions of the Settlement Agreement that are not adopted in this decision, not any other aspect of the Settlement Agreement.

4. Pacific Gas and Electric Company (PG&E) is granted flexibility in incorporating the revenue requirements authorized to be collected, through rates and authorized ratemaking accounting mechanisms, over the remainder of this rate case cycle through December 31, 2019 (i) the test year revenue requirement set forth in Appendix A of this decision, less (ii) the amount collected by PG&E base rates since January 1, 2017, and prior to the implementation of the revenue requirement authorized by this decision, plus (iii) interest on the difference between (i) and (ii), with said interest based on the rate for prime, three-month commercial paper reported in Federal Reserve Statistical Release H-15. PG&E shall work with the Commission's Energy Division to determine the timing of the requisite rate changes.

5. Within 30 days from the effective date of this decision, Pacific Gas and Electric Company shall file a Tier 1 advice letter with revised tariff sheets to implement (i) the revenue requirement authorized in Ordering Paragraph 4 above, and set forth in Appendix A, and (ii) all accounting procedures, fees, and charges authorized in this decision that are not addressed in any other advice letters required by this decision. The revised tariff sheets shall (a) become effective on filing, subject to a finding of compliance by the Commission's Energy Division, (b) comply with General Order 96-B, and (c) apply to service rendered on or after their effective date.

6. As part of the advice letter filing ordered in Ordering Paragraph 5, Pacific Gas and Electric Company (PG&E) shall submit a detailed analysis that provides the information listed below. If the Energy Division rejects PG&E's advice letter because PG&E's analysis is insufficient, the Commission shall require PG&E to take remedial action.

   1. A mathematical demonstration, with reference to specific line items in PG&E's General Rate Case (GRC) testimony and/or workpapers in the record of this proceeding, that accounts for the $300 million in 2017 cost reductions announced by PG&E on January 11, 2017. The demonstration should show whether, after accounting for $300 million in reductions, PG&E is still planning to spend, on a forecast basis, the 2017 revenue requirement authorized in this decision, or some other specified amount. Annotated copies of the pages cited in the referenced testimony and/or workpapers shall be included as an attachment to the analysis.
   2. Separate verification and demonstration, by reference to testimony or workpapers in the record of this proceeding, that the reductions in executive positions also announced by PG&E on January 11, 2017 are accounted for in the GRC forecast for executive compensation that is part of the 2017 revenue requirement authorized in this decision. If the announced reductions are in fact already funded as part of the authorized amount, PG&E should provide a revised forecast that removes those costs for 2017. Annotated copies of the pages cited in the referenced testimony and/or workpapers shall be included as an attachment to the analysis.

7. Pacific Gas and Electric Company (PG&E) is authorized to implement attrition revenue requirement increases for the years 2018 and 2019 of $444 million and $361 million, respectively. PG&E shall include these fixed revenue requirement attrition amounts for 2018 and 2019 in its Annual Electric True-Up and Annual Gas True-Up filings.

8. Pacific Gas and Electric Company (PG&E), the City of Hayward, and Commission staff are directed to meet and confer to determine a joint estimate of the scope and funding required for an audit of PG&E's Rule 20A program. Other governmental entities that are parties to this proceeding shall be also invited to the meet and confer session. PG&E and the City of Hayward shall jointly file and serve the joint estimate of the scope and the required funding within 60 days of the effective date of this decision. The assigned Commissioner and assigned Administrative Law Judge shall determine further procedural steps following receipt and review of the audit scope and funding estimate.

9. Pacific Gas and Electric Company shall pay for the audit mandated in Ordering Paragraph 8 with part of its 2017 authorized Rule 20A budget.

10. Pacific Gas and Electric Company (PG&E) shall file a Tier 2 Advice Letter within 30 days of the effective date of this decision to establish a one-way Rule 20A balancing account that tracks the annual capital and expense costs for Rule 20A undergrounding projects, on a forecast and recorded basis. Overcollected balances in the account shall remain available for future Rule 20A projects. The Commission shall review the balances in the account in PG&E's next General Rate Case proceeding.

11. Pacific Gas and Electric Company (PG&E) shall file a Tier 2 Advice Letter within 30 days of the effective date of this decision to establish a two-way tax memorandum account to record any revenue differences resulting from the income tax expenses forecasted in its General Rate Case (GRC) proceedings, and the tax expenses incurred by PG&E during this 2017-2019 GRC period and each subsequent GRC period.

a. This tax memorandum account shall remain open and the balance in the account shall be reviewed in every subsequent GRC until a Commission decision closes the account.

b. The account shall have separate line items detailing the differences between tax expenses forecasted and tax expenses incurred, specifically resulting from 1) net revenue changes, 2) mandatory tax law changes, tax accounting changes, tax procedural changes, or tax policy changes, and 3) elective tax law changes, tax accounting changes, tax procedural changes or tax policy changes.

12. Pacific Gas and Electric Company shall notify the Energy Division of the California Public Utilities Commission of any tax-related changes, tax-related accounting changes or any tax-related procedural changes that materially affect or may materially affect revenues. "Materially affect" is defined as a potential increase or decrease of $3 million or more.

13. Pursuant to Public Utilities Code Section 706, Pacific Gas and Electric Company (PG&E) shall within 45 days of today's date, file a Tier 2 Advice Letter to establish an "Executive Compensation Memorandum Account."

a. The memorandum account shall track all monies authorized in today's decision for the annual salaries, bonuses, benefits, and all other consideration of any value, set aside to be paid to the officers of the utility, and to track that against the salaries, bonuses, benefits, and all other consideration of any value, paid to its officers.

b. The advice letter establishing the memorandum accounts shall define the "officers" of PG&E who are subject to the provisions of Public Utilities Code Section 706.

c. PG&E shall follow the requirements of Public Utilities Code Section 706 if it seeks to have ratepayers pay for the "excess compensation" that may have been paid to or owed to an officer in connection with a "triggering event."

14. All advice letters filed by Pacific Gas and Electric Company pursuant to this Order shall comply with General Order 96-B and are subject to a finding of compliance by the Energy Division or its successor.

15. Pacific Gas and Electric Company shall report on the results of its discussions with the California Division of Safety of Dams within 60 days of the date of this decision, by sending a letter to the Director of the Commission's Safety and Enforcement Division and serving a copy of that letter on the service list of this proceeding.

16. The Commission's Safety and Enforcement Division (SED) shall meet and confer with Pacific Gas and Electric Company (PG&E) and other interested parties following the issuance of this decision to ensure that PG&E's ongoing reporting activities, as reflected throughout the Settlement Agreement, are implemented in a manner that best suits SED's purposes.

17. The disputed proposal that this General Rate Case of Pacific Gas and Electric Company should encompass four years is denied without prejudice.

18. Pacific Gas and Electric Company shall submit its next General Rate Case application according to the schedule adopted by the Commission in Decision 14-12-025.

19. The disputed proposal to authorize Pacific Gas and Electric Company to establish a new balancing account to record costs to comply with gas leak management requirements that may emerge from Commission Rulemaking 15-01-008 is denied without prejudice.

20. Pacific Gas and Electric Company (PG&E) shall prepare a complete update of Table 3 and Table 4 from Decision 09-03-026, following the instructions provided in Section 5 of this decision, and file and serve that update in this proceeding no later than 60 days after the date of today's decision. The assigned

Commissioner and assigned Administrative Law Judge shall determine further procedural steps upon receipt of PG&E's updated analysis.

21. Application 15-09-001 shall be closed following the filing of a "Notice to Accept PG&E's Adopted Test Year 2017 Revenue Requirement" and disposition of the compliance items ordered in this decision:

a. Filing and service of the SmartMeter Update calculations as instructed in Section 5 of this Decision.

b. Filing and service of the Rule 20A audit plan described in Section 4.1.3.7 of this Decision.

22. In the event a "Motion Requesting Other Relief" is filed in connection with Application (A.) 15-09-001, A.15-09-001 shall remain open until a decision or ruling resolves the motion, and the issues 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 order is effective today.

Dated May 11, 2017, at Merced, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners

Appendix A

Pacific Gas and Electric Company

2017 General Rate Case

Decision Tables - Test Year 2017 and Post Test Years 2018 and 2019

Appendix A

Pacific Gas and Electric Company

2017 General Rate Case

Decision Tables - Test Year 2017 and Post Test Years 2018 and 2019

APPENDIX A
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Decision Tables

TABLE INDEX

APPENDIX A: Table 1
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC) - Line of Business (LOB) Position Summary
LOB Summary of Adopted Increase Over Authorized 2016 General Rate Case
(Millions of Dollars)

Line		1/1/2016 Authorized (Note 1)	Settlement: 2017 Proposed	Settlement: Difference from Authorized	Adopted: 2017 Proposed	Adopted: 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	649	711	62	711	62	0	1
2	Customer Services	181	193	12	193	12	0	2
3	Administrative & General	472	382	(90)	382	(90)	0	3
4	Less: Revenue Credits (OORs & Wheeling)	(88)	(118)	(30)	(118)	(30)	0	4
5	FF&U, Other Adjs, Taxes Other than Income	78	82	4	82	4	0	5
6	Return, Taxes, Depreciation, and Amortization	2,920	2,901	(19)	2,901	(19)	0	6
7	Retail Revenue Requirement	4,213	4,151	(62)	4,151	(62)	0	7
	Gas Distribution							
8	Operation and Maintenance	375	433	58	433	58	0	8
9	Customer Services	138	139	1	139	1	0	9
10	Administrative & General	260	259	(2)	259	(2)	0	10
11	Less: Revenue Credits (OORs & Wheeling)	(25)	(28)	(3)	(28)	(3)	0	11
12	FF&U, Other Adjs, Taxes Other than Income	48	50	2	50	2	0	12
13	Return, Taxes, Depreciation, and Amortization	945	886	(59)	886	(59)	0	13
14	Retail Revenue Requirement	1,742	1,738	(3)	1,738	(3)	0	14
	Electric Generation							
15	Operation and Maintenance	640	650	10	650	10	0	15
16	Customer Services	0	2	2	2	2	0	16
17	Administrative & General	278	272	(6)	272	(6)	0	17
18	Less: Revenue Credits (OORs & Wheeling)	(18)	(6)	12	(6)	12	0	18
19	FF&U, Other Adjs, Taxes Other than Income	(89)	37	126	37	126	0	19
20	Return, Taxes, Depreciation, and Amortization	1,150	1,159	9	1,159	9	0	20
21	Retail Revenue Requirement	1,962	2,115	153	2,115	153	0	21
	Total GRC							
22	Operation and Maintenance	1,664	1,794	131	1,794	131	0	22
23	Customer Services	319	334	15	334	15	0	23
24	Administrative & General	1,011	912	(99)	912	(99)	0	24
25	Less: Revenue Credits (OORs & Wheeling)	(131)	(152)	(21)	(152)	(21)	0	25
26	FF&U, Other Adjs, Taxes Other than Income	38	170	132	170	132	0	26
27	Return, Taxes, Depreciation, and Amortization	5,016	4,946	(70)	4,946	(70)	0	27
28	Retail Revenue Requirement	7,916	8,004	88	8,004	88	0	28

Note (1): These amounts include revenues from PG&E's 2014 GRC Decision 14-08-032, adjusted for 2015 and 2016 attrition. Also included are the 2016 adopted revenue requirements associated with Solar PV Projects, Smart Grid Pilots, Revised Customer Energy Statement, Share My Data, SmartMeterTM Opt-Out, DCPP Long Term Seismic Program, and Hercules Municipal Utility Assets. These amounts exclude pension costs.

APPENDIX A: Table 2
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC) - Position Summary
Results Of Operations Summary of Adopted Increase Over Authorized 2016 General Rate Case
Results of Operations - Test Year 2017
(Millions of Dollars)

			Settlement		Adopted			
Line No.	Description	1/1/2016 Authorized (*Note 1*)	2017 Proposed	Difference from Authorized	2017 Proposed	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	7,916	8,004	88	8,004	88	0	1
2	Plus Other Operating Revenue	131	152	21	152	21	0	2
3	Total Operating Revenue	8,047	8,157	110	8,157	110	0	3
	OPERATING EXPENSES:							
4	Energy Costs	0	0	0	0	0	0	4
5	Production / Procurement	640	647	7	647	7	0	5
6	Storage	0	0	0	0	0	0	6
7	Transmission	5	7	2	7	2	0	7
8	Distribution	1,018	1,140	122	1,140	122	0	8
9	Customer Accounts	313	293	(21)	293	(21)	0	9
10	Uncollectibles	26	27	1	27	1	0	10
11	Customer Services	6	41	36	41	36	0	11
12	Administrative and General	1,011	912	(99)	912	(99)	0	12
13	Franchise & SFGR Tax Requirement	76	66	(10)	66	(10)	0	13
14	Amortization	71	0	(71)	0	(71)	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	(176)	(30)	146	(30)	146	0	17
18	Subtotal Expenses:	2,990	3,105	114	3,105	114	0	18
	TAXES:							
19	Superfund	0	0	0	0	0	0	19
20	Property	282	278	(4)	278	(4)	0	20
21	Payroll	108	103	(5)	103	(5)	0	21
22	Business	1	1	0	1	0	0	22
23	Other	3	3	(0)	3	(0)	0	23
24	State Corporation Franchise	134	82	(52)	82	(52)	0	24
25	Federal Income	465	227	(238)	227	(238)	0	25
26	Total Taxes	992	693	(299)	693	(299)	0	26
27	Depreciation	2,122	2,395	273	2,395	273	0	27
28	Fossil/Hydro Decommissioning	36	3	(33)	3	(33)	0	28
29	Nuclear Decommissioning	0	0	0	0	0	0	29
30	Total Operating Expenses	6,141	6,196	55	6,196	55	0	30
31	Net for Return	1,906	1,961	55	1,961	55	0	31
32	Rate Base	23,645	24,331	685	24,331	685	0	32
	RATE OF RETURN:							
33	On Rate Base		**8.06%**		**8.06%**			33
34	On Equity		**10.40%**		**10.40%**			34

Note (1): These amounts include revenues from PG&E's 2014 GRC Decision 14-08-032, adjusted for 2015 and 2016 attrition. Also included are the 2016 adopted revenue requirements associated with Solar PV Projects, Smart Grid Pilots, Revised Customer Energy Statement , Share My Data, SmartMeterTM Opt-Out, DCPP Long Term Seismic Program, and Hercules Municipal Utility Assets. These amounts exclude pension costs.

APPENDIX A: Table 3
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Results of Operations at Proposed Rates - Test Year 2017
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	Settlement	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
	REVENUE:				
1	Revenue Collected in Rates	8,004,486	8,004,486	0	1
2	Plus Other Operating Revenue	152,094	152,094	0	2
3	Total Operating Revenue	8,156,580	8,156,580	0	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	647,426	647,426	0	5
6	Storage	0	0	0	6
7	Transmission	7,116	7,116	0	7
8	Distribution	1,139,910	1,139,910	0	8
9	Customer Accounts	292,872	292,872	0	9
10	Uncollectibles	27,277	27,277	0	10
11	Customer Services	41,321	41,321	0	11
12	Administrative and General	912,183	912,183	0	12
13	Franchise & SFGR Tax Requirement	66,204	66,204	0	13
14	Amortization	176	176	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	(29,915)	(29,915)	0	17
18	Subtotal Expenses:	3,104,570	3,104,570	0	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	277,715	277,715	0	20
21	Payroll	102,518	102,518	0	21
22	Business	1,058	1,058	0	22
23	Other	2,516	2,516	0	23
24	State Corporation Franchise	82,152	82,152	0	24
25	Federal Income	226,995	226,995	0	25
26	Total Taxes	692,954	692,954	0	26
27	Depreciation	2,394,911	2,394,911	0	27
28	Fossil/Hydro Decommissioning	3,094	3,094	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	6,195,529	6,195,529	0	30
31	Net for Return	1,961,051	1,961,051	0	31
32	Rate Base	24,330,655	24,330,655	0	32
	RATE OF RETURN:				
33	On Rate Base	8.06%	8.06%		33
34	On Equity	10.40%	10.40%		34

APPENDIX A: Table 3-A
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Results of Operations at Proposed Rates - Test Year 2017
Electric Distribution Summary
(Thousands of Dollars)

Line No.	Description	Settlement	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
	REVENUE:				
1	Revenue Collected in Rates	4,151,048	4,151,048	0	1
2	Plus Other Operating Revenue	117,977	117,977	0	2
3	Total Operating Revenue	4,269,025	4,269,025	0	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	0	0	0	5
6	Storage	0	0	0	6
7	Transmission	1,066	1,066	0	7
8	Distribution	710,221	710,221	0	8
9	Customer Accounts	173,659	173,659	0	9
10	Uncollectibles	14,454	14,454	0	10
11	Customer Services	19,048	19,048	0	11
12	Administrative and General	381,817	381,817	0	12
13	Franchise & SFGR Tax Requirement	33,346	33,346	0	13
14	Amortization	0	0	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	(6,420)	(6,420)	0	17
18	Subtotal Expenses:	1,327,191	1,327,191	0	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	167,698	167,698	0	20
21	Payroll	39,116	39,116	0	21
22	Business	453	453	0	22
23	Other	1,076	1,076	0	23
24	State Corporation Franchise	72,073	72,073	0	24
25	Federal Income	181,580	181,580	0	25
26	Total Taxes	461,996	461,996	0	26
27	Depreciation	1,364,495	1,364,495	0	27
28	Fossil/Hydro Decommissioning	0	0	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	3,153,681	3,153,681	0	30
31	Net for Return	1,115,344	1,115,344	0	31
32	Rate Base	13,838,010	13,838,010	0	32
	RATE OF RETURN:				
33	On Rate Base	**8.06%**	**8.06%**		33
34	On Equity	**10.40%**	**10.40%**		34

APPENDIX A: Table 3-B
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Results of Operations at Proposed Rates - Test Year 2017
Gas Distribution Summary
(Thousands of Dollars)

Line No.	Description	Settlement (A)	Adopted (B)	Difference (C) = (B) - (A)	Line No.
	REVENUE:				
1	Revenue Collected in Rates	1,738,493	1,738,493	0	1
2	Plus Other Operating Revenue	28,091	28,091	0	2
3	Total Operating Revenue	1,766,584	1,766,584	0	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	3,286	3,286	0	5
6	Storage	0	0	0	6
7	Transmission	0	0	0	7
8	Distribution	429,689	429,689	0	8
9	Customer Accounts	116,810	116,810	0	9
10	Uncollectibles	5,642	5,642	0	10
11	Customer Services	22,273	22,273	0	11
12	Administrative and General	258,547	258,547	0	12
13	Franchise & SFGR Tax Requirement	16,291	16,291	0	13
14	Amortization	0	0	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	(3,495)	(3,495)	0	17
18	Subtotal Expenses:	849,043	849,043	0	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	53,820	53,820	0	20
21	Payroll	30,790	30,790	0	21
22	Business	297	297	0	22
23	Other	707	707	0	23
24	State Corporation Franchise	(14,482)	(14,482)	0	24
25	Federal Income	(50,406)	(50,406)	0	25
26	Total Taxes	20,726	20,726	0	26
27	Depreciation	480,014	480,014	0	27
28	Fossil/Hydro Decommissioning	0	0	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	1,349,782	1,349,782	0	30
31	Net for Return	416,801	416,801	0	31
32	Rate Base	5,171,234	5,171,234	0	32
	RATE OF RETURN:				
33	On Rate Base	**8.06%**	**8.06%**		33
34	On Equity	**10.40%**	**10.40%**		34

APPENDIX A: Table 3-C

Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Results of Operations at Proposed Rates - Test Year 2017
Electric Generation Summary
(Thousands of Dollars)

Line No.	Description	Settlement (A)	Adopted (B)	Difference (C) = (B) - (A)	Line No.
	REVENUE:				
1	Revenue Collected in Rates	2,114,946	2,114,946	0	1
2	Plus Other Operating Revenue	6,025	6,025	0	2
3	Total Operating Revenue	2,120,971	2,120,971	0	3
	OPERATING EXPENSES:				
4	Energy Costs	0	0	0	4
5	Production / Procurement	644,140	644,140	0	5
6	Storage	0	0	0	6
7	Transmission	6,050	6,050	0	7
8	Distribution	0	0	0	8
9	Customer Accounts	2,403	2,403	0	9
10	Uncollectibles	7,181	7,181	0	10
11	Customer Services	0	0	0	11
12	Administrative and General	271,819	271,819	0	12
13	Franchise & SFGR Tax Requirement	16,567	16,567	0	13
14	Amortization	176	176	0	14
15	Wage Change Impacts	0	0	0	15
16	Other Price Change Impacts	0	0	0	16
17	Other Adjustments	(20,000)	(20,000)	0	17
18	Subtotal Expenses:	928,336	928,336	0	18
	TAXES:				
19	Superfund	0	0	0	19
20	Property	56,197	56,197	0	20
21	Payroll	32,612	32,612	0	21
22	Business	308	308	0	22
23	Other	733	733	0	23
24	State Corporation Franchise	24,561	24,561	0	24
25	Federal Income	95,821	95,821	0	25
26	Total Taxes	210,233	210,233	0	26
27	Depreciation	550,402	550,402	0	27
28	Fossil/Hydro Decommissioning	3,094	3,094	0	28
29	Nuclear Decommissioning	0	0	0	29
30	Total Operating Expenses	1,692,065	1,692,065	0	30
31	Net for Return	428,906	428,906	0	31
32	Rate Base	5,321,410	5,321,410	0	32
	RATE OF RETURN:				
33	On Rate Base	**8.06%**	**8.06%**		33
34	On Equity	**10.40%**	**10.40%**		34

APPENDIX A: Table 4
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Income Taxes at Proposed Rates - Test Year 2017
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	Settlement	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
1	Revenues	8,156,580	8,156,580	0	1
2	O&M Expenses	3,104,570	3,104,570	0	2
3	Nuclear Decommissioning Expense	0	0	0	3
4	Superfund Tax	0	0	0	4
5	Taxes Other Than Income	383,807	383,807	0	5
6	Subtotal	4,668,203	4,668,203	0	6
	DEDUCTIONS FROM TAXABLE INCOME:				
7	Interest Charge Adjustment	630,164	630,164	0	7
8	Fiscal/Calendar Property Tax Adjustment	7,159	7,159	0	8
9	Operating Expense Adjustments	43,455	43,455	0	9
10	Repair Deduction	884,334	884,334	0	10
11	Removal Cost Adjustment	169,250	169,250	0	11
12	Vacation Pay Adjustment	(2,944)	(2,944)	0	12
13	Capitalized Software Adjustment	114,924	114,924	0	13
14	Subtotal Deductions	1,846,343	1,846,343	0	14
	CCFT TAXES:				
15	CCFT Capitalized Interest Adjustment	6,631	6,631	0	15
16	CCFT Tax Depreciation - Declining Balance	0	0	0	16
17	CCFT Tax Depreciation - Fixed Assets	1,738,663	1,738,663	0	17
18	CCFT Tax Depreciation - Other	0	0	0	18
19	Capitalized Overhead - Cost For Gas Invent	0	0	0	19
20	Other Adjustment	0	0	0	20
21	Subtotal Deductions	3,591,636	3,591,636	0	21
22	Taxable Income for CCFT	1,076,567	1,076,567	0	22
23	CCFT	95,168	95,168	0	23
24	State Tax Adjustment	(3,987)	(3,987)	0	24
25	Current CCFT	91,182	91,182	0	25
26	Deferred Taxes - Reg Asset	0	0	0	26
27	Deferred Taxes - Interest	586	586	0	27
28	Deferred Taxes - Vacation	(260)	(260)	0	28
29	Deferred Taxes - Other	0	0	0	29
30	Deferred Taxes - Fixed Assets	(9,355)	(9,355)	0	30
31	Total CCFT	82,152	82,152	0	31
	FEDERAL TAXES:				
32	CCFT - Prior Year Adjustment	101,317	101,317	0	32
33	FIT Capitalized Interest Adjustment	(773)	(773)	0	33
34	FIT Tax Depreciation - Declining Balance	0	0	0	34
35	FIT Tax Depreciation - SLRL	0	0	0	35
36	FIT Tax Depreciation - Fixed Assets	2,110,996	2,110,996	0	36
37	FIT Tax Depreciation - Other	0	0	0	37
38	Capitalized Overhead - Cost For Gas Invent	0	0	0	38
39	Other Adjustment	0	0	0	39
40	FIT Preferred Dividend Adjustment	2,712	2,712	0	40
41	Subtotal Deductions	4,060,595	4,060,595	0	41
42	Taxable Income for FIT	607,608	607,608	0	42
43	Federal Income Tax	212,663	212,663	0	43
44	Deferred Taxes - Reg Asset	(4,138)	(4,138)	0	44
45	Tax Effect of MTD & Prod Tax Credits	(10,287)	(10,287)	0	45
46	Deferred Taxes - Interest	(270)	(270)	0	46
47	Deferred Taxes - Vacation	(1,030)	(1,030)	0	47
48	Deferred Taxes - Other	0	0	0	48
49	Deferred Taxes - Fixed Assets	30,058	30,058	0	49
50	Total Federal Income Tax	226,995	226,995	0	50

APPENDIX A: Table 4-A
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Income Taxes at Proposed Rates - Test Year 2017
Electric Distribution Summary
(Thousands of Dollars)

Line No.	Description	Settlement	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
1	Revenues	4,269,025	4,269,025	0	1
2	O&M Expenses	1,327,191	1,327,191	0	2
3	Nuclear Decommissioning Expense	0	0	0	3
4	Superfund Tax	0	0	0	4
5	Taxes Other Than Income	208,343	208,343	0	5
6	Subtotal	2,733,491	2,733,491	0	6
	DEDUCTIONS FROM TAXABLE INCOME:				
7	Interest Charge Adjustment	358,404	358,404	0	7
8	Fiscal/Calendar Property Tax Adjustment	3,401	3,401	0	8
9	Operating Expense Adjustments	52,797	52,797	0	9
10	Repair Deduction	425,076	425,076	0	10
11	Removal Cost Adjustment	126,751	126,751	0	11
12	Vacation Pay Adjustment	(1,259)	(1,259)	0	12
13	Capitalized Software Adjustment	49,019	49,019	0	13
14	Subtotal Deductions	1,014,189	1,014,189	0	14
	CCFT TAXES:				
15	CCFT Capitalized Interest Adjustment	1,772	1,772	0	15
16	CCFT Tax Depreciation - Declining Balance	0	0	0	16
17	CCFT Tax Depreciation - Fixed Assets	865,653	865,653	0	17
18	CCFT Tax Depreciation - Other	0	0	0	18
19	Capitalized Overhead - Cost For Gas Invent	0	0	0	19
20	Other Adjustment	0	0	0	20
21	Subtotal Deductions	1,881,614	1,881,614	0	21
22	Taxable Income for CCFT	851,877	851,877	0	22
23	CCFT	75,306	75,306	0	23
24	State Tax Adjustment	(867)	(867)	0	24
25	Current CCFT	74,439	74,439	0	25
26	Deferred Taxes - Reg Asset	0	0	0	26
27	Deferred Taxes - Interest	157	157	0	27
28	Deferred Taxes - Vacation	(111)	(111)	0	28
29	Deferred Taxes - Other	0	0	0	29
30	Deferred Taxes - Fixed Assets	(2,411)	(2,411)	0	30
31	Total CCFT	72,073	72,073	0	31
	FEDERAL TAXES:				
32	CCFT - Prior Year Adjustment	73,383	73,383	0	32
33	FIT Capitalized Interest Adjustment	935	935	0	33
34	FIT Tax Depreciation - Declining Balance	0	0	0	34
35	FIT Tax Depreciation - SLRL	0	0	0	35
36	FIT Tax Depreciation - Fixed Assets	1,070,510	1,070,510	0	36
37	FIT Tax Depreciation - Other	0	0	0	37
38	Capitalized Overhead - Cost For Gas Invent	0	0	0	38
39	Other Adjustment	0	0	0	39
40	FIT Preferred Dividend Adjustment	301	301	0	40
41	Subtotal Deductions	2,159,318	2,159,318	0	41
42	Taxable Income for FIT	574,173	574,173	0	42
43	Federal Income Tax	200,961	200,961	0	43
44	Deferred Taxes - Reg Asset	(900)	(900)	0	44
45	Tax Effect of MTD & Prod Tax Credits	0	0	0	45
46	Deferred Taxes - Interest	327	327	0	46
47	Deferred Taxes - Vacation	(441)	(441)	0	47
48	Deferred Taxes - Other	0	0	0	48
49	Deferred Taxes - Fixed Assets	(18,367)	(18,367)	0	49
50	Total Federal Income Tax	181,580	181,580	0	50

APPENDIX A: Table 4-B
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Income Taxes at Proposed Rates - Test Year 2017
Gas Distribution Summary
(Thousands of Dollars)

Line No.	Description	Settlement (A)	Adopted (B)	Difference (C) = (B) - (A)	Line No.
1	Revenues	1,766,584	1,766,584	0	1
2	O&M Expenses	849,043	849,043	0	2
3	Nuclear Decommissioning Expense	0	0	0	3
4	Superfund Tax	0	0	0	4
5	Taxes Other Than Income	85,613	85,613	0	5
6	Subtotal	831,928	831,928	0	6
	DEDUCTIONS FROM TAXABLE INCOME:				
7	Interest Charge Adjustment	133,935	133,935	0	7
8	Fiscal/Calendar Property Tax Adjustment	2,645	2,645	0	8
9	Operating Expense Adjustments	(22,142)	(22,142)	0	9
10	Repair Deduction	392,114	392,114	0	10
11	Removal Cost Adjustment	24,588	24,588	0	11
12	Vacation Pay Adjustment	(826)	(826)	0	12
13	Capitalized Software Adjustment	33,701	33,701	0	13
14	Subtotal Deductions	564,014	564,014	0	14
	CCFT TAXES:				
15	CCFT Capitalized Interest Adjustment	(525)	(525)	0	15
16	CCFT Tax Depreciation - Declining Balance	0	0	0	16
17	CCFT Tax Depreciation - Fixed Assets	408,252	408,252	0	17
18	CCFT Tax Depreciation - Other	0	0	0	18
19	Capitalized Overhead - Cost For Gas Invent	0	0	0	19
20	Other Adjustment	0	0	0	20
21	Subtotal Deductions	971,741	971,741	0	21
22	Taxable Income for CCFT	(139,814)	(139,814)	0	22
23	CCFT	(12,360)	(12,360)	0	23
24	State Tax Adjustment	(569)	(569)	0	24
25	Current CCFT	(12,929)	(12,929)	0	25
26	Deferred Taxes - Reg Asset	0	0	0	26
27	Deferred Taxes - Interest	(46)	(46)	0	27
28	Deferred Taxes - Vacation	(73)	(73)	0	28
29	Deferred Taxes - Other	0	0	0	29
30	Deferred Taxes - Fixed Assets	(1,433)	(1,433)	0	30
31	Total CCFT	(14,482)	(14,482)	0	31
	FEDERAL TAXES:				
32	CCFT - Prior Year Adjustment	1,562	1,562	0	32
33	FIT Capitalized Interest Adjustment	(543)	(543)	0	33
34	FIT Tax Depreciation - Declining Balance	0	0	0	34
35	FIT Tax Depreciation - SLRL	0	0	0	35
36	FIT Tax Depreciation - Fixed Assets	590,063	590,063	0	36
37	FIT Tax Depreciation - Other	0	0	0	37
38	Capitalized Overhead - Cost For Gas Invent	0	0	0	38
39	Other Adjustment	0	0	0	39
40	FIT Preferred Dividend Adjustment	39	39	0	40
41	Subtotal Deductions	1,155,136	1,155,136	0	41
42	Taxable Income for FIT	(323,208)	(323,208)	0	42
43	Federal Income Tax	(113,123)	(113,123)	0	43
44	Deferred Taxes - Reg Asset	(591)	(591)	0	44
45	Tax Effect of MTD & Prod Tax Credits	0	0	0	45
46	Deferred Taxes - Interest	(190)	(190)	0	46
47	Deferred Taxes - Vacation	(289)	(289)	0	47
48	Deferred Taxes - Other	0	0	0	48
49	Deferred Taxes - Fixed Assets	63,787	63,787	0	49
50	Total Federal Income Tax	(50,406)	(50,406)	0	50

APPENDIX A: Table 4-C
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Income Taxes at Proposed Rates - Test Year 2017
Electric Generation Summary
(Thousands of Dollars)

Line No.	Description	Settlement	Adopted	Difference	Line No.
		(A)	(B)	(C) = (B) - (A)	
1	Revenues	2,120,971	2,120,971	0	1
2	O&M Expenses	928,336	928,336	0	2
3	Nuclear Decommissioning Expense	0	0	0	3
4	Superfund Tax	0	0	0	4
5	Taxes Other Than Income	89,850	89,850	0	5
6	Subtotal	1,102,784	1,102,784	0	6
	DEDUCTIONS FROM TAXABLE INCOME:				
7	Interest Charge Adjustment	137,825	137,825	0	7
8	Fiscal/Calendar Property Tax Adjustment	1,113	1,113	0	8
9	Operating Expense Adjustments	12,800	12,800	0	9
10	Repair Deduction	67,144	67,144	0	10
11	Removal Cost Adjustment	17,911	17,911	0	11
12	Vacation Pay Adjustment	(858)	(858)	0	12
13	Capitalized Software Adjustment	32,205	32,205	0	13
14	Subtotal Deductions	268,140	268,140	0	14
	CCFT TAXES:				
15	CCFT Capitalized Interest Adjustment	5,384	5,384	0	15
16	CCFT Tax Depreciation - Declining Balance	0	0	0	16
17	CCFT Tax Depreciation - Fixed Assets	464,757	464,757	0	17
18	CCFT Tax Depreciation - Other	0	0	0	18
19	Capitalized Overhead - Cost For Gas Invent	0	0	0	19
20	Other Adjustment	0	0	0	20
21	Subtotal Deductions	738,281	738,281	0	21
22	Taxable Income for CCFT	364,503	364,503	0	22
23	CCFT	32,222	32,222	0	23
24	State Tax Adjustment	(2,550)	(2,550)	0	24
25	Current CCFT	29,672	29,672	0	25
26	Deferred Taxes - Reg Asset	0	0	0	26
27	Deferred Taxes - Interest	476	476	0	27
28	Deferred Taxes - Vacation	(76)	(76)	0	28
29	Deferred Taxes - Other	0	0	0	29
30	Deferred Taxes - Fixed Assets	(5,511)	(5,511)	0	30
31	Total CCFT	24,561	24,561	0	31
	FEDERAL TAXES:				
32	CCFT - Prior Year Adjustment	26,372	26,372	0	32
33	FIT Capitalized Interest Adjustment	(1,166)	(1,166)	0	33
34	FIT Tax Depreciation - Declining Balance	0	0	0	34
35	FIT Tax Depreciation - SLRL	0	0	0	35
36	FIT Tax Depreciation - Fixed Assets	450,423	450,423	0	36
37	FIT Tax Depreciation - Other	0	0	0	37
38	Capitalized Overhead - Cost For Gas Invent	0	0	0	38
39	Other Adjustment	0	0	0	39
40	FIT Preferred Dividend Adjustment	2,372	2,372	0	40
41	Subtotal Deductions	746,142	746,142	0	41
42	Taxable Income for FIT	356,643	356,643	0	42
43	Federal Income Tax	124,825	124,825	0	43
44	Deferred Taxes - Reg Asset	(2,647)	(2,647)	0	44
45	Tax Effect of MTD & Prod Tax Credits	(10,287)	(10,287)	0	45
46	Deferred Taxes - Interest	(408)	(408)	0	46
47	Deferred Taxes - Vacation	(300)	(300)	0	47
48	Deferred Taxes - Other	0	0	0	48
49	Deferred Taxes - Fixed Assets	(15,362)	(15,362)	0	49
50	Total Federal Income Tax	95,821	95,821	0	50

APPENDIX A: Table 5
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Adopted Rate Base - Test Year 2017
Electric and Gas Departments Summary
(Thousands of Dollars)

Line No.	Description	Electric Distribution	Gas Distribution	Electric Generation	Total Year 2017	Line No.
		(A)	(B)	(C)	(D)	
	WEIGHTED AVERAGE PLANT:					
1	Plant Beginning Of Year (BOY)	29,526,820	11,174,699	15,436,713	56,138,232	1
2	Net Additions	682,014	458,401	191,315	1,331,729	2
3	Total Weighted Average Plant	30,208,834	11,633,100	15,628,027	57,469,961	3
	WORKING CAPITAL:					
4	Material and Supplies - Fuel	0	0	0	0	4
5	Material and Supplies - Other	75,586	19,803	130,334	225,722	5
6	Working Cash	206,765	129,976	195,986	532,727	6
7	Total Working Capital	282,350	149,779	326,320	758,449	7
	ADJUSTMENTS FOR TAX REFORM ACT:					
8	Deferred Capitalized Interest	(2,647)	(442)	28,354	25,265	8
9	Deferred Vacation	16,652	10,925	11,341	38,918	9
10	Deferred CIAC Tax Effects	368,418	95,369	395	464,182	10
11	Total Adjustments	382,424	105,851	40,091	528,366	11
12	CUSTOMER ADVANCES	70,007	26,414	0	96,421	12
	DEFERRED TAXES					
13	Accumulated Regulatory Assets	0	0	(15,478)	(15,478)	13
14	Accumulated Fixed Assets	3,414,433	960,816	1,130,754	5,506,003	14
15	Accumulated Other	0	0	0	0	15
16	Deferred ITC	31,125	15,881	193,208	240,214	16
17	Deferred Tax - Other	0	0	0	0	17
18	Total Deferred Taxes	3,445,558	976,697	1,308,484	5,730,739	18
19	DEPRECIATION RESERVE	13,520,034	5,714,384	9,364,543	28,598,961	19
20	TOTAL Ratebase	13,838,010	5,171,234	5,321,410	24,330,655	20

APPENDIX A: Table 6
Pacific Gas and Electric Company
2017 CPUC General Rate Case (GRC)
Adopted Post-Test Year Revenue Requirements (RRQ)

Line No.	Line of Business	Test Year 2017 Forecast	Attrition Year 2018 2018 Forecast	Attrition Increase	Attrition Allocation	Attrition Increase Percentage	Attrition Year 2019 2019 Forecast	Attrition Increase	Attrition Allocation	Attrition Increase Percentage	Line No.
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	
1	Electric Generation	2,114,946	2,198,946	84,000	18.9%	4.0%	2,268,946	70,000	19.4%	3.2%	1
2	Electric Distribution	4,151,048	4,401,048	250,000	56.3%	6.0%	4,596,048	195,000	54.0%	4.4%	2
3	Gas Distribution	1,738,493	1,848,493	110,000	24.8%	6.3%	1,944,493	96,000	26.6%	5.2%	3
4	Revenue Collected in Rates Total	$ 8,004,486	$ 8,448,486	**$ 444,000**	100.0%	**5.5%**	$ 8,809,486	**$ 361,000**	100.0%	**4.3%**	4

(End of Appendix A)