Decision **PROPOSED DECISION OF ALJ PULSIFER** (Mailed 6/18/2014)

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, 2014 (U39M).	Application 12-11-009 (Filed November 15, 2012)
And Related Matter.	Investigation 13-03-007

DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S GENERAL RATE CASE REVENUE REQUIREMENT FOR 2014-2016

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DECISION AUTHORIZING PACIFIC GAS AND ELECTRIC COMPANY'S GENERAL RATE CASE REVENUE REQUIREMENT FOR 2014-2016

Introduction

This decision approves test year revenue requirements increases of $460 million, (for a 6.9% increase) for Pacific Gas and Electric Company (PG&E) pursuant to its 2014 General Rate Case (GRC) Application 12-11-009 and Investigation 13-03-007, as summarized in Appendix C, Table 1. The adopted 2014 revenue requirements shall become effective upon filing of tariffs pursuant to the directives of this decision.[1] The adopted revenue requirement reflects our careful assessment of PG&E's 2014 test year base revenue requirements necessary to provide safe and reliable service. Appendix C of this decision contains the results of operations supporting tables for PG&E, which incorporates the forecasted costs we find to be reasonable, and which are adopted in today's decision.

This decision also authorizes attrition rate adjustments of 4.57% for 2015 and 5% for 2016 as set forth in Appendix D to provide funds necessary for PG&E to continue to provide safe and reliable service to customers beyond the test year,

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[1] Decision (D.) 13-04-023 granted PG&E's unopposed motion, filed February 15, 2013, seeking an order to make its 2014 test year GRC revenue requirement effective as of January 1, 2014, even in the event the Commission issues a final decision after that date. D.13-04-023 also granted PG&E's request to allow for the recovery of interest, based on a Federal Reserve three-month commercial paper rate, (*see* Federal Reserve three-month Commercial Paper Rate – Non-Financing, from the Federal Reserve Statistical Release H.15 or its successor. http://www.federalreserve.gov/releases/H15/data.html.), to the extent necessary to keep PG&E and its ratepayers relatively indifferent to the timing of the Commission's final decision regarding the 2014 GRC revenue requirement.

while offering a reasonable opportunity to earn the rate of return previously found reasonable by the Commission.

PG&E's final updated request for its total 2014 forecasted revenue requirement increase is $1.160 billion, representing a 17.5% increase, and requested attrition year increases of $436 million and $486 million for 2015 and 2016, respectively.

PG&E requested test year 2014 revenue increases of $514 million in Electric Distribution, $446 million in Gas Distribution, and $199 million in Electric Generation for the test year. PG&E claims these significant increases in revenue requirements are needed for:

- delivering energy safely to customers, maintaining reliability, and providing responsive customer service;
- capital investments to replace aging infrastructure;
- increased capacity to meet customer growth;
- depreciation associated with plant investments; and
- complying with governmental regulations and orders to address nuclear operations, hydroelectric relicensing, and potential risks to public safety applicable to electric and gas systems and facilities.

The authorized increase in revenue requirement reflects the costs forecast for test year 2014 for delivering electricity to PG&E's customers, and for operating and maintaining PG&E's gas distribution and electric distribution and generation utility infrastructure. The revenue requirement authorized in this decision does not include commodity costs of electricity procured for customers or costs of fuel used in generating electricity, which are addressed in a separate proceeding. The gas department revenue requirement authorized in this decision does not include the commodity cost of gas procured to serve gas

customers or gas transmission and storage, which are addressed in separate proceedings.

PG&E's revenue requirement estimates are classified by the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts, augmented by Major Work Category (MWC), which PG&E uses for operational planning, budgeting and managing purposes. Consistent with prior GRCs, costs have been separated into Unbundled Cost Categories and aggregated into functional areas by MWC or FERC account. The adopted revenue requirements are presented in Appendix C in "Results of Operations" format.

PG&E's GRC forecast utilizes 2011 as the recorded base year for developing 2014 expense forecasts. PG&E's 2014 rate base forecast utilizes recorded year-end 2011 as a starting point, and adds forecasted annual capital expenditures for 2012-2014 to arrive at a rate base forecast for test year 2014. As a result, our adopted 2014 rate base incorporates forecasts for cumulative capital expenditures each year from 2012 through 2014 for each respective cost category. Although PG&E also presents forecasts of capital expenditures for 2015 and 2016, no other party had the resources to undertake a comprehensive scrutiny of 2015 and 2016 capital forecasts. Accordingly, while we make limited findings in this decision that relate, in some instances, to 2015 and 2016 activities, without the benefit of a robust review from other parties, we have insufficient evidentiary basis to make comprehensive findings as to the overall reasonableness of PG&E's 2015 and 2016 capital forecasts. We instead adopt a simplified methodology for an attrition revenue requirement for 2015 and 2016, as set forth in Appendix D, as described in Section 12 of this decision. Our adopted 2014 revenue requirements in comparison to PG&E's requested amounts are as follows:

2014 Revenue Requirements: PG&E Requested Versus Commission Adopted
$ in Millions

	Authorized Revenues at Existing Rates	PG&E Proposed Increase	Adopted $ Increase	Adopted % Increase
Electric Distribution	$3.650	$ 514	$125	3.4%
Gas Distribution	$1.295	$ 446	$264	20.4%
Electric Generation	$1.689	$ 199	$ 71	4.2%
Total GRC	$6.634	$1,160	$460	6.9%

PG&E asks the Commission to adopt the total and rate component changes necessary to implement the change in revenue requirements resulting from this proceeding. We authorize PG&E to implement rate changes based on the adopted Results of Operations Revenue Requirements set forth in Appendix C which shall be consolidated with rate changes implemented in PG&E's Annual Gas and Electric True-Up filing scheduled to be effective as directed herein.

As the basis for the revenue requirements increases that we adopt herein, we make the following major findings regarding PG&E's proposals:

Gas Distribution

Our adopted gas distribution funding includes:

- Support for a Gas Distribution Control Center to provide real-time visibility and remote control of dynamic gas pressure and flows within the system.
- Mapping and Records project funding to collect, transport, standardize and electronically archive as-built and gas service paper records.
- Distribution Integrity Management Program funding to enhance safety mitigating risk factors such as corrosion, natural forces, excavation damage, material, weld, or joint failure, or equipment failure.

- Pipe, Meter, and other Preventive Maintenance funding to forestall equipment degradation and failure and to promote a safer system.
- Funding to meet a superior standard of safety in detection and repair of gas distribution pipeline hazardous leaks, using various enhanced techniques. It is PG&E's responsibility to determine the frequency of routine leak surveys. PG&E must evaluate the optimal phase-in of all enhanced measures to reduce hazardous leaks.
- A two-way balancing account is adopted for leak-survey, leak repair, meter set leak repair atmospheric corrosion inspections and tee cap repair to adjust the recoverable costs to the extent the actual scope of work differs from the forecast up to a prescribed cap.
- Funding for natural gas vehicles, capacity reliability, leak replacement emergency response, and high pressure regulator replacement.
- Funding to accelerate the rate of replacement of aging distribution pipeline, focused on pipe materials with the highest leak rate. Adopted funding redirects more money to plastic pipe replacement, and results in a slightly higher total mileage rate of replacement compared to PG&E's forecast.
- Increasing staffing of gas service representatives, to more quickly respond to gas odor calls and other emergency calls.

Electric Distribution

Adopted Electric Distribution Funding includes the following provisions:

- Funding for the Electric Distribution Geographic Information System/Asset Management (GIS/AM) project to validate, enhance, and convert legacy mapping and asset connectivity data to a single GIS.
- Mapping and Records Management initiatives for: (1) Records Quality Assurance; (2) Field Asset Inventory;

(3) Conversion of Paper Records to Electronic Format; and
(4) Electronic Records Update.

- Inspection, testing, repair and replacement of electric distribution facilities, and new initiatives to proactively replace aging assets that pose safety and/or reliability risks. Requested funding is reduced for idle facilities removal.
- Increasing resources to reduce electric outages and mitigate wildfire risk, with focus on vegetation management, wildfire patrols, and modification of recloser controls in high-risk fire areas.
- Upgrading PG&E's weather prediction model to better prepare for storms and expanding use of SmartMeter™ data to restore services sooner to customers affected by outages.
- Expanding use of Supervisory Control and Data Acquisition equipment to monitor, control, and remotely shut off electricity during emergencies.
- Funding for accelerated pole inspections to complete a 10-year inspection cycle on schedule. For ratemaking purposes, however, the portion of pole inspections that constitute deferred maintenance will be paid out of shareholder earnings.
- Funding to complete the replacement of poles previously scheduled for replacement in prior years. A reduction is adopted, however, to assign a share of responsibility to PG&E shareholders, rather than ratepayers, for pole replacement deferrals previously funded by ratepayers.
- A two-way balancing account is adopted to cover the costs of responding to major emergencies and catastrophic events, where such costs cannot be recovered through the Catastrophic Event Memorandum Account mechanism.
- The one-way Vegetation Management Balancing Account and Incremental Inspection and Removal Cost Tracking Account are continued.

- The Electric Tariff Rule 20A work credit allocation amount of $41.3 million that was adopted in the 2011 GRC decision is continued through 2016.
- PG&E's proposed rate design for LED street lights is adopted.

Customer Care

Adopted Customer Care funding includes:

- A new methodology is adopted for setting PG&E's uncollectible factor based on elements of PG&E's and The Utility Reform Network's (TURN) proposals.
- PG&E's proposed changes to customer fees (i.e., the non-sufficient funds fee and reconnection fees) are adopted.
- PG&E is authorized to close its Service Disconnection Memorandum Account and recover costs through the annual true up rate processes.
- Ongoing cost recovery of capital-related revenue requirement associated with the SmartMeter™ program up to the authorized cost cap is consolidated with the 2014 GRC revenue requirement.
- The electric and gas SmartMeter™ Balancing Accounts are closed, including elimination of the SmartMeter™ Benefits Realization Mechanism, and the electric and gas Meter Reading Cost Balancing Accounts.
- The SmartMeter™ program reporting requirements are concluded.
- Cost-recovery of the capital-related revenue requirement associated with the SmartMeter™ Opt-Out Program is consolidated with the 2014 GRC revenue requirement.

Energy Supply

Adopted Energy Supply Funding includes:

- Funding for hydroelectric operations to maintain reliability and support aging infrastructure. Funding includes

relicensing costs, new licensing conditions, and dam safety modifications to achieve more stringent safety guidelines from the FERC and Division of Safety of Dams.

- TURN's proposed reduction to remove ratepayer funding for certain lower priority hydro projects is adopted.
- Increasing the use of automation and employing efficiencies to improve use of the existing water supply is approved.
- Investment in facilities to address the risks to public safety is approved.
- Diablo Canyon Power Plant Funding includes performing a dual refueling scheduled for 2014, investing in projects intended to minimize extended shutdowns, and implementing cybersecurity precautions.
- Capital expenditures are authorized for the fuel cell project approved in Decision 10-04-028.
- PG&E's updated forecasts for fossil decommissioning of existing and retired power plants are approved.
- PG&E's forecast 2014 weighted average fuel oil inventory is approved.
- Two-way balancing accounts are approved for managing the capital and expense forecasts associated with new FERC Hydro licensing implementation and for nuclear energy safety and security related rulemakings and orders.
- PG&E's proposal is approved to credit back to customers the savings associated with the first three years of its photovoltaic generation program.
- The joint recommendation of PG&E, TURN and Marin Energy Authority is approved to credit back to customers funds received from the successful litigation with the Department of Energy.

Shared Services

Adopted Shared Services Funding includes provisions for:

- Funding for additional safety professionals to support field operations, and implement Information Technology (IT) solutions to improve safety work management.
- Funding for vehicle fleet replacements; real estate improvements to maintain aging infrastructure and seismically upgrade buildings to ensure reliability of buildings that house critical business operations, but with reductions in PG&E's forecasts to reflect lower cost assumptions in certain cases.
- A significant upgrade to PG&E's primary procurement system; as well as funding for major Information Technology initiatives, but subject to a 14% reduction for IT forecasts prepared using the Concept Cost Estimating Tool, as proposed by the Division of Ratepayer Advocates (DRA).

Human Resources

Adopted funding for Human Resources includes:

- Funding for PG&E's Short-Term Incentive Plan (STIP) for eligible non-officer employees is approved subject to exclusion of funding for the metrics for Customer Satisfaction and Earnings from Operations (EFO), and further applying a 10% reduction to reflect a sharing of costs and benefits between ratepayers and shareholders.
- Funding for employee health plan and post-retirement benefits are approved.
- Funding is approved for PG&E's Rewards and Recognition Program.
- DRA's recommendations as to the treatment of Long-Term Incentive Plan and Paid Time Off in future total compensation studies are denied.
- The Greenlining Institute's recommendation regarding cultural sensitivity training is denied.

Administrative and General (A&G)

Funding for A&G Department costs including:

- A 50/50 sharing between ratepayers and shareholders of the costs of Directors' and Officers' liability insurance.
- A reduction in PG&E's forecast for the PG&E Academy and Talent Management programs.
- Denial of increased ratepayer funding for additional regulatory department personnel.
- Denial of ratepayer funding for PG&E's Currents website and Next 100 blog.

Results of Operations

The Results of Operations include the following major provisions:

- Only bonus depreciation enacted by the date provided for update filings is incorporated in test year revenue requirements.
- PG&E's forecast of Other Operating Revenue is increased to reflect increased timber sales revenue and increased water sales.
- PG&E's forecasts for depreciation parameters for uncontested asset accounts are adopted.
- For deprecation parameters for contested asset accounts, PG&E's forecasts for average service lives and survivor curves are adopted.
- For depreciation parameters for contested asset accounts, cost to cover negative net salvage rates are increased over current rates but at a reduced level relative to PG&E's forecasts to mitigate ratepayer impacts and to reflect the principle of gradualism.

Rate Base, Working Cash and Finance Issues

- The existing ratemaking policy of excluding nuclear fuel inventory from rate base is continued, subject to further review and possible revision in PG&E's next cost of capital proceeding.
- The revenue requirements for customer deposits are reduced by imputing financing costs based on short-term interest rates.

- PG&E computations for working cash are approved.

Settlement and Joint Proposals

We adopt the settlements and joint proposals as described in Section 13, and as set forth in Appendix E of this decision.

The authorizations adopted in this decision are made pursuant to applicable statutory divisions of the Public Utilities Code, Commission Standard Practices, the Commission's Rules of Practice and Procedure, and prior decisions, orders, and resolutions of the Commission.

Requirements for the 2017 General Rate Case

We also approve the following uncontested proposals that PG&E has presented to improve its showing on safety and risk in its next GRC filing for test year 2017 (2017 GRC):

- PG&E will 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.
- PG&E will 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 will 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 this GRC cycle to account for its spending by MWC, comparing authorized amounts to budgeted and spent amounts, and explaining significant differences.

1. Procedural Background

Pacific Gas and Electric Company (PG&E) tendered its 2014 General Rate Case (GRC) Notice of Intent on July 2, 2012, and served a Notice of Availability on the service list from its 2011 GRC. The Division of Ratepayer Advocates (DRA)[2] accepted the tendered documents on September 14, 2012. PG&E filed its GRC application on November 15, 2012, for Phase 1, proposing to increase gas and electric base revenue requirements by $1.282 billion based on a 2014 test year, with additional increases for attrition covering 2015 and 2016 amounting to $492 million and $504 million, respectively.

PG&E describes the steps it took to prepare its 2014 GRC in compliance with prior Commission decisions in Exhibit 42, Chapter 8. PG&E listed 35 items related to prior decisions and described the compliance activity or status of each item. PG&E complied with directives from the last GRC to provide testimony and workpapers on proposed new types of costs, as well as the processes and criteria used to develop these materials. PG&E has provided budget reports for its spending by Major Work Category (MWC) that describe reallocations each year.

PG&E also argues that the requirement for an annual report describing improvements to PG&E's website has outlived its usefulness and should be discontinued. No party has opposed PG&E's request to discontinue the

[2] The Division of Ratepayer Advocates changed its name to the Office of Ratepayer Advocates (ORA) September 26, 2013, pursuant to Senate Bill (SB) 96. For purposes of this decision, we refer to ORA by its previous name, Division of Ratepayer Advocates, as was used during the course of most of the litigation in this proceeding.

reporting on PG&E's website improvements. We accordingly relieve PG&E of this obligation.

Protests to PG&E's application were filed on December 17, 2012. Prehearing Conference (PHC) Statements were filed on January 8, 2013. Protests and/or PHC Statements were filed by DRA, The Utility Reform Network (TURN), the City and County of San Francisco (CCSF), the Greenlining Institute (Greenlining), the Center for Electrosmog Prevention (CEP), the Coalition of California Utility Employees (CCUE), Merced And Modesto Irrigation Districts (Irrigation Districts), the Marin Energy Authority (MEA), the Alliance for Retail Energy Markets, the Direct Access Customer Coalition, Engineers and Scientists of California (ESC), and the National Asian American Coalition and Ecumenical Center for Black Church Studies.

PG&E replied to the protests on December 21, 2012. On January 11, 2013, the Commission held a duly noticed PHC to determine parties, create the service list, identify issues, consider the schedule, and address other matters necessary to proceed. The assigned Commissioner issued a Scoping Memo on January 22, 2013.[3] On February 6, 2013, motions for party status were granted for the Alliance for Nuclear Responsibility and the Small Business Utility Advocates.

On March 21, 2013, the Commission issued Order Instituting Investigation (I.) 13-03-007, the companion investigation to this GRC. The purpose of I.13--03-007, which was consolidated with Application (A.) 12-11-009, is to allow

[3] On June 9, 2014, an amended scoping memo was issued, indicating that prospective recommendations relating to safety consultant reports would be treated in a separate decision after the Commission adopts 2014-2016 revenue requirements.

the Commission to (1) address matters raised by parties other than PG&E, and (2) issue orders on matters for which PG&E might not be the proponent.

During May and June 2012, public participation hearings for this proceeding were held in San Francisco, San Bruno, Fresno, Bakersfield, Santa Rosa, Oakland, Chico, San Jose, Soledad, and San Luis Obispo. Speakers addressed a variety of issues ranging from impacts of proposed rate increases on customers to PG&E's safety measures and structure reliability. In addition, a number of letters and e-mails were received concerning the GRC application. Many of the public comments received expressed opposition to the rate increases due to a variety of concerns, including the state of the California economy, and customers' economic circumstances. Others expressed support for PG&E's proposed revenue increase based on the view that the rate increase would support necessary infrastructure improvements to promote safe and reliable service. We have considered this public input in developing this decision.

DRA presented testimony on May 3, 2013. DRA recommended a $146 million decrease in Electric Distribution, an $83 million increase in Gas Distribution, and a $99 million decrease in Electric Generation (EG) compared to the most recent authorized revenues.

Intervenors presented testimony on May 17, 2013. PG&E presented rebuttal testimony on May 28, 2013. Evidentiary hearings were held beginning July 15, 2013 and continued through August 9, 2013. During the hearings, the testimony of various parties, together with several cross-examination exhibits and various errata and updates were admitted into evidence. Motions were also filed for approval of Settlements on certain limited issues. A Joint Comparison

Exhibit was served on August 23, 2013. Opening Briefs were filed on September 6, 2013 and reply briefs on September 27, 2013.[4] On October 4, 2013, PG&E submitted its update testimony (Exh. 375; (PG&E-32)), limited to updating its non-labor escalation rates. No party contested the update, and we reflect those results in Appendix C.

1.1. Framework for Preparing this Decision

This decision is organized in the sequence of topics generally set forth in the common briefing outline utilized in this proceeding. Since evidence and arguments in this proceeding are voluminous, we focus discussion on the major points of contention and do not summarize every nuance of each party's positions.

Similarly, due to the volume of the record and issues, we have not explicitly described every single issue raised during the proceeding. To do so would have increased the size of this decision even beyond its current length. That does not mean, however, that we have overlooked issues raised by parties. We have reviewed the record, as well as the arguments made, and considered all issues raised in deciding revenue requirements and related policy directives adopted herein. In all other respects, this decision does not address revenue requirements for electric transmission, gas transmission and storage, Public Purpose Programs (PPPs) and conservation programs, except for allocating common costs.

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[4] By ruling dated April 4, 2014, the ALJ granted a March 18, 2014 of PG&E to reopen the record and to receive updates to correct certain errors, as set forth in the motion. We have reflected the corrected data in our adopted results.

PG&E's gas distribution and electric distribution and generation revenue requirement claimed cost increases cover: Operations and Maintenance (O&M) expense; Customer Services expense; Administrative and General (A&G) expense; payroll taxes, franchise fees, and uncollectibles; a fair return on rate base; taxes and depreciation; and Other Operating Revenue.

As a basis for deciding issues in this proceeding, we determine whether PG&E has met the burden of proving that it is entitled to the relief sought in this proceeding, and of affirmatively establishing the reasonableness of all aspects of the application. With the burden of proof placed on PG&E, the Commission has held that the standard of proof PG&E must meet is that of a preponderance of evidence. Preponderance of the evidence usually is defined in terms of probability of truth, e.g., such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth. PG&E must present more evidence that supports the requested result than would support an alternative outcome.

In Decision (D.) 11-05-018 (PG&E'S 2011 GRC), the Commission required that as part of its showing in the current proceeding , PG&E fully describe any reprioritizations and deferrals of costs explicitly identified in the Settlement Agreement or costs that can reasonably be imputed from the Settlement Agreement. PG&E was to 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 the prior GRC.

For previously deferred activities and projects being requested again, PG&E was to fully explain why they are needed now when they were able to be deferred before. As stated in D.11-05-018, we critically evaluate previously requested activities or projects that were deferred and requested again, keeping

in mind that the utility has the obligation to maintain its operations and plant in the condition to provide efficient, safe and reliable service, even if that condition requires more expenditures than the Commission had authorized.

2. Balancing Safety and Risk Concerns with Just and Reasonable Rates

We have reviewed this record to determine whether or to what extent PG&E's GRC proposal is founded on an appropriate and explicit safety and security risk assessment. We have previously adopted the Legislature's overall policy statement: "It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates."[5]

Public Utilities Code Sections 961 and 963, enacted by SB 705 (Ch. 522, Stats. 2011), require each gas corporation to develop and implement a plan for the "safe and reliable operation of its commission-regulated gas pipeline facility that implements the policy of paragraph (3) of subdivision (b) of Section 963, subject to approval, modification, and adequate funding by the commission."

Pub. Util. Code § 451 requires that each public utility in California must "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."

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[5] Pub. Util. Code § 963(b)(3).

Consistent with this statutory guidance, we face the task of adopting an appropriate level of utility funding to ensure safe and reliable service, while keeping rates affordable, and allowing a fair rate of return. We expect the utilities to make safety a foundational priority. When evaluating the revenue requirements requested by PG&E, the Commission has placed a priority on programs that enhance safety and reliability of the natural gas and electric power infrastructure and operations.

In this context, we also take note of Rulemaking (R.13-11-006) which is addressing whether and how the Commission should formalize rules to ensure the effective use of a risk-based decision-making framework to evaluate safety and reliability improvements presented in GRC applications, develop necessary performance metrics and evaluation tools, and modify the Rate Case Plan documentation requirements for the investor owned energy utilities.

DRA and TURN, among other parties, claim that PG&E has failed to adequately support that its proposed increases are necessary to provide safe and reliable service, and has not shown that the claimed benefits justify the costs to be incurred. PG&E also claims, that DRA's and TURN's recommended funding levels would prevent, or at least delay, PG&E's ability to implement adopting best practices for its gas distribution business and implementing safety initiatives in the electric distribution and energy supply businesses. PG&E claims DRA and TURN recommendations represent a disproportionate focus on minimizing cost to the detriment of safety. PG&E claims that, DRA's and TURN's proposed funding reductions, if adopted, would directly contravene the Commission's commitment to ensure that safety remains PG&E's top priority. PG&E notes that many of its proposed projects are not being initiated for cost savings purposes, but to comply with legal and regulatory requirements, improve customer service,

enhance safety, increase environmental benefits and for various other non-cost related reasons.

Ensuring that the management of investor-owned gas utility systems fully performs its duty of safe operations is a core obligation of this Commission. The California legislature has enacted statutory language that codifies in more explicit terms the priority placed upon safety of the public and utility employees. As provided in Pub. Util. Code § 961(e), the Commission and each gas corporation must "provide opportunities for meaningful, substantial, and ongoing participation by the gas corporation workforce in the development and implementation of the plan, with the objective of developing an industry-wide culture of safety that will minimize accidents, explosions, fires, and dangerous conditions for the protection of the public and the gas corporation workforce."

Among public utility facilities, natural gas transmission and distribution pipelines present the greatest public safety challenges. Gas pipelines carry flammable gas under pressure. These pipelines are typically located in public right-of-ways, at times in densely populated areas. The dimensions of the threat to public safety from natural gas pipeline systems, including the pace at which death and life-altering injuries can occur, are more extreme than other public utility systems. This unique feature requires that natural gas system operators and this Commission assume a different perspective when considering natural gas system operations. This perspective must include a planning horizon commensurate with that of the pipelines; that is, in perpetuity, and awareness of the extreme public safety consequences of neglecting safe system construction and operation. In this proceeding, we have approved the largest share of cost increases for gas distribution.

Our concern regarding public utility safety covers not just natural gas service, however, but extends to electric service, as well. On September 23, 2010, the Commission created an Independent Review Panel (IRP) of experts to conduct a comprehensive study and investigation of the September 9, 2010, San Bruno natural gas pipeline explosion and fire. The Commission directed the Panel to make a technical assessment of the events, determine the root causes, and offer recommendations for action by the Commission to best ensure such an accident is not repeated elsewhere. The IRP issued a report in June 2012. Among the issues addressed in the IRP Report was how to better incorporate safety into ratemaking.

In accordance with this concern, by letter dated March 5, 2012, from the Commission's Executive Director to PG&E's Senior Vice President of Regulatory Affairs, PG&E was directed to conduct a review focused on operational and public safety issues as part of the GRC.[6] Pursuant to the above-referenced March 5, 2012 letter from the Executive Director, the Safety and Enforcement Division (SED) also commissioned two reports from independent consultants to evaluate PG&E's electric and gas operations from a safety and risk perspective, and in anticipation of PG&E's testimony which was to include a risk assessment of its gas distribution, and electric distribution and generation systems.

SED retained the Cycla Corporation (Cycla) and the Liberty Consultant Group (Liberty) as consultants to evaluate risk assessments, risk mitigation, programs and policies, as well as PG&E corporate policies, goals, culture and the efforts being made to bolster PG&E system safety and reliability. These

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[6] *See* Exh. 53 (PG&E -18), at 11A-1-3.

consultant reports were issued to the service list by ruling dated May 17, 2013. A third consultant report by Overland Consulting was issued by ruling dated May 31, 2013, and presented the results of a financial audit of PG&E's Gas Distribution System. Pursuant to the Executive Director's letter, PG&E was directed to include in this GRC "a risk assessment that underlies [PG&E's] rate requests" in order to satisfy the GRC's focused on safety in addition to rates. The Executive Director further stated that, "[a]s part of the capital investing planning that PG&E performs, PG&E should perform and provide a risk assessment of its entire system, both gas and electric, and a comparison to industry best practices." The letter continued, "For example, PG&E should give a risk assessment of its physical system as well as a description of and a justification for the company's risk mitigation programs and policies. PG&E should provide to identify and prioritize areas of risk and include the underlying rationale for [PG&E's] assessment."

Although PG&E is in the process of developing the data and models to do a system-wide risk assessment, PG&E's GRC filing does not explicitly include such a risk assessment and justification of its risk mitigation programs and policies. Based on the GRC filing, Liberty observed that despite material progress by PG&E, "one cannot now use PG&E's risk assessments to assess in reasonably robust ways the probabilities and consequences of failures associated with safety and security risks."[7]

PG&E was also directed to identify and prioritize areas of risk and to include the underlying rationale for its assessments. PG&E was to present

[7] *See* Exh 168, Liberty Report at 17.

testimony detailing the overall policy of the utility's safety and security measures, including physical security and cyber security of the system. PG&E was to detail how safety and security measures are incorporated into its corporate policies, goals, and culture, and the efforts being made to bolster system safety and security.

Safe and reliable service means that the utility must have accurate records about its facilities, have a trained professional workforce, and take appropriate actions to keep its system facilities safely operational in conformity with applicable laws, regulations, and policies. The Commission has carefully reviewed PG&E's funding request to determine the potential impacts to public and employee safety at the competing funding level requested by the parties.

PG&E explains that in selecting measures to mitigate identified safety and reliability risks, it chose the measures that move the utility toward first quartile safety performance cost-effectively and considered cost in determining the pace of implementing these measures. PG&E states that it developed implementation plans to accomplish the selected mitigation measures. The Liberty consultants concluded, however, that while PG&E identified and quantified spending on safety and security measures in reasonable detail in its GRC filing, PG&E "overused" the "safety" label. The Liberty consultants found that much of what PG&E designates as "safety" falls under what others consider to be baseline and reliability work. The Liberty Group observed regarding PG&E's analysis of costs and benefits that:

> The GRC has generally not documented how expenditures to address safety and security are in proportion to or otherwise

> aligned with identified risks identified. [sic] PG&E has generally not demonstrated analytically that the benefits of proposed safety and security risk mitigation measures justify their costs.[8]

Both the Cycla (gas distribution) and Liberty (electric) studies noted limitations in PG&E's showing as to the impact, if any, of its proposed activities on reducing safety risks. As Cycla explained, PG&E's GRC filing "does not present a clear logical linkage between safety risk and the activities designed to control them."[9] Liberty likewise "could not assess whether the degree of risk reduction can be expected to reach a level considered satisfactory from customer, public, and employee perspectives."[10]

The Liberty consultants "queried PG&E about the adequacy of its foundation for concluding that expenditures to address safety and security and security risks are in proportion to risks properly identified. [The Liberty consultants] could not find substantial documentation of this type of thinking or analysis, although [they] consider such support to be consistent with the expectations created by the March 5 letter [from the Executive Director] and by the areas of inquiry included in our scope for this study."[11] Cycla likewise did not find substantial documentation showing that PG&E's planned expenditures to address safety and security risks are in proportion to the risks properly

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[8] Exh. 168, Liberty Report at S-4.

[9] Exh. 167, Cycla Report at 61.

[10] Exh. 168, Liberty Report at 19.

[11] *Id*. at 19.

identified. Cycla found no analytical demonstration that the expected benefits of proposed safety and security measures justify their estimated costs.

As affirmed in data responses and oral testimony, Cycla did not specifically analyze the reasonableness of PG&E's cost forecasts, and Cycla's use of the phrase "reasonable costs" was not intended to state or imply that the costs are appropriate or acceptable as part of a rate determination.

Regarding the question of what level of safety is appropriate as a benchmark to set the revenue requirement, the Liberty consultants observed:

> The notion of never being safe enough, or risk-free enough, makes sense in certain specialized industries (like radiation protection), but surely does not apply universally. In addition, the approach is fraught with logistical problems. The desirability of substantially increasing customer rates in the name of maximizing safety raises its own set of issues. A commonly expressed [as-low-as-reasonably-practicable) ALARP notion is that added expenditures are warranted to the extent that the mitigation benefits are not "grossly disproportionate" to the associated costs. That standard would be very troubling for the electric industry.[12]

Liberty "did not observe a substantial level of quantification of cost for safety and security related projects and programs initiatives proposed in the GRC. For the most part, cost savings for these initiatives were not quantified. PG&E instead focused primarily on narrative justifications of the projects; e.g., defining reasons requiring the expenditures and addressing qualitatively the sort of consequences that could occur in their absence." (Liberty Report at 42.)

Liberty concludes that:

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[12] Exh. 168, Liberty Report at 11.

> despite material progress by PG&E, it remains the case that one cannot now use PG&E's risk assessments to assess in reasonably robust ways the probabilities and consequences of failures associated with safety and security risks.

The Liberty consultants further observed that:

> PG&E's normal practice with regard to budgeting is to target its annual spending levels near its GRC-authorized levels. Doing so allows a return on equity near authorized levels to be attained. (Report at 34.)

2.1. Role of Cost-Benefit Analysis in Revenue Requirements Determinations

A key issue in this proceeding is what standards and evidentiary showings should be required of PG&E to justify charging ratepayers for its proposed spending for new programs, or for changes to existing programs, as necessary to meet appropriate standards of public and employee safety and service reliability.

Both TURN and DRA have questioned PG&E claimed justification for authorizing cost increases for new programs for which PG&E did not conduct a cost-benefit analysis, or examine other alternatives. PG&E responds that many programs and activities are not suited to cost-benefit analysis because they are required by law, are a necessary prerequisite to achieving public policy goals, or involve new technology where there is insufficient data to measure benefits. Also, PG&E argues that some benefits (e.g., improved safety and reliability) are not easily measureable.

The cost benefit analysis PG&E prepared in support of its GRC filing (included both in Working Papers provided as part of the GRC filing and in Business Cases provided in response to Cycla information requests) qualitatively describes the anticipated impact of the planned Risk Control Mitigations. Cycla

notes, however, that PG&E did not attempt to estimate the quantitative benefits of the planned risk control measures.

As noted by Cycla, in the GRC filing, PG&E does not describe in detail its proposed process to use in translating rate case allowable costs into detailed implementation decisions (such as which pipe segments to replace). PG&E also does not include a systematic analysis of the impact of uncertainties in sources of risk and in risk central measure performance on its decisions regarding which control measures to select. Absent detailed knowledge of future implementation decisions, PG&E would be unable to evaluate the associated risk reduction.

The Liberty consultant similarly noted that PG&E's GRC showing "lacks a rationale for why the chosen aggregate spending levels are appropriate and how they were determined." The Liberty consultant concluded that: "in terms of overall technical adequacy of PG&E's GRC sharing, costs and project justifications are included in the work papers, but a credible [cost-benefit analysis] CBA is not. [The Liberty consultants] emphasize that CBAs are problematic in areas such as safety – they are neither easy nor are they typically fruitful. This does not mean they should not be addressed when practical."[13]

In evaluating PG&E's cost claims, we require that unless a work activity or program is mandated, the utility must demonstrate that the overall benefits justify the costs imposed on ratepayers. Although quantitative benefits may not necessarily exceed the costs, such benefits should be quantified as much as possible. Any qualitative benefits being relied upon should also be identified

[13] Exh. 168, Liberty Report at 28.

and explained. It is not enough to merely assert that safety would be compromised absent approval of a particular work effort.

Virtually everything a utility does some nexus to safety and can be deemed to have some safety impact, but the emphasis should be on those initiatives that deliver the optimal safety improvement in relation to the ratepayer dollars spent. The required cost-benefit analysis enables the Commission to distinguish these two types of work efforts. As noted in the Liberty report, the notion of never being safe enough, or risk-free enough, makes sense in certain specialized industries, but does not apply universally. In the context of public utility rate regulation, Liberty states that the ability to balance costs and benefits of risk mitigation measures is the "lynchpin" of reducing risks to a level considered "as low as reasonably practicable" (ALARP).[14]

The Cycla Report notes that an alternative way to apply the ALARP principle is to look to the risk control practices currently used by the top industry performers as a proxy for an "acceptable level of risk" or to determine measures that are "reasonably practicable. Under such an approach, the fact that top industry performers have implemented such practices is deemed to be a de facto judgment made by both regulators and industry that these activities are reasonable and practicable.

PG&E should demonstrate that it compared the cost of alternative approaches to performing the work activity and that the proposed approach is the most cost-effective. The burden is on PG&E to establish that its proposed work activities are necessary, and that it has prudently examined alternatives

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[14] *Id.* at 10-11.

before receiving ratepayer funding. PG&E's policy witnesses agreed in principle that, for all proposed programs, even those justified on the basis of safety, PG&E's GRC showing must demonstrate both (1) the need for and reasonableness of PG&E's proposed programs, supported in most cases by a well explained cost-benefit analysis; and (2) that the proposed approach is the most cost-effective method available to the utility. We have reviewed PG&E's showing to determine if it has demonstrated that the overall benefits justify the additional costs expected to be incurred taking into consideration the observations and caveats noted by Liberty and Cycla, as discussed above. We have carefully evaluated PG&E's justifications of costs both in terms of quantified cost savings and qualitative benefits that PG&E did not or could not quantify. We have also considered the basis for objections to approval of cost increases as raised by various opposing parties. In weighing the qualitative benefits in relation to costs, however, it is not enough merely for PG&E to make assertions that benefit will result. In addressing PG&E's proposals, as discussed throughout this decision, given the limitations in PG&E's cost/benefit showing, we have used our best judgment to weigh both the quantitative and qualitative benefits in relation to the costs involved for each program or project. In many cases, based on our weighing of overall benefits versus costs, we approve funding for the new or expanded programs proposed by PG&E. In other cases, we approve program funding, but reduce the level of funding below what PG&E requested or based on a more extended time schedule. In other cases, we decline to approve any funding for certain programs where we find that the claimed benefits do not justify the costs to ratepayers.

For purposes of this decision, we limit our review of the Safety Division Consultant Reports to those matters that have a bearing on the determination of

the adopted 2014 revenue requirements. To the extent that the Consultant Reports present conclusions and recommendations that relate to prospective actions that PG&E should take beyond the 2014 test year to improve and enhance its management relating to safety and reliability, we shall separately address those issues in a separate decision in this proceeding.

3. Natural Gas Distribution

3.1. Introduction

PG&E' natural gas distribution system includes 42,000 miles of distribution main and 3.3 million services. PG&E forecasts expense for 2014 of $461.1 million to: (1) own, operate, and maintain distribution plant and a portion of common and general plant; (2) acquire gas supplies for core gas customers; and (3) provide services to gas customers. PG&E proposes that up to $147.1 million of these costs be recoverable through a balancing account for leak survey, leak repair, meter set leak repair and atmospheric corrosion (AC) inspection costs. PG&E's forecast represents a 97% increase in gas department operations expense for 2014 compared to 2011. The largest drivers for the expense increase are gas leak repair, field services and dispatch to meet emergency response goals, Distribution Integrity Management, and new technology.

PG&E forecasts a 2014-2016 increase in capital expenditures for gas distribution of $831.3 million, $856 million, and $782 million, respectively. This increase represents 170 % more than 2011 levels, primarily due to accelerated pipeline replacement and a new Gas Distribution Control Center (Control Center), new buildings, new customer connections and work requested by others, and new technology.

3.2. Gas System Operations and Distribution Control

PG&E forecasts 2014 operating expense of $13 million MWC FG and $6.1 million for planning and engineering (MWC GG) related to a new Control Center, co-located with a new gas dispatch and transmission control center. The Control Center will mitigate inherent system risk and provide constant, real-time visibility into the dynamic pressure and flows within the gas distribution system. It will have remote control capability for regulators and valves, which will enable responsive centralized system operations.

Cycla concludes that PG&E's plans for a distribution operations control center is consistent with best operators' practices, and staffing plans are consistent with PG&E's implementation time frame. Cycla warns, however, that the time frame for achieving operability and training operators in a new control environment may take longer than PG&E forecasts.

PG&E's MWC FG forecast includes $8.835 million in Control Center-related staffing and contractor support. DRA does not dispute the need for the new Control Center, but recommends reducing PG&E's MWC FG forecast by $4.650 million, and reducing PG&E's MWC GG forecast by $401,000. DRA's dispute relates to staffing levels and contractor support for the Gas Control Center. PG&E and DRA staffing level estimates for the Control Center differ as follows:

Control Center Staffing Forecast

Forecasted Number of Positions

Position Description	**PG&E**	**DRA**
Control Room Staff	25	21
Clearance Personnel	5	0
System Operations	4	0
Technology Support	9	3
Management Positions	3	0
Total	46	24

Discussion

As discussed further below, we conclude that PG&E has justified the need for the new Gas Control Center, and the need for the forecasted additional positions once the Control Center is fully operational. We question, however, whether full operation of the Control Center will occur as early as 2014. Given the concerns raised by Cycla that PG&E's pace of implementation may be overly optimistic, our adopted forecast reflects a somewhat longer phase in period than that anticipated by PG&E. Given the uncertainties involved, it is difficult to predict precisely how much time may be needed. We anticipate, however, that extending the implementation time for capital expenditures over a time period extending into 2015, as discussed further below, provides a more reasonable basis for setting 2014 revenue requirements.

We agree with PG&E's forecast of number of new positions for Control Center staffing as described in the following section. Control Room Staff

PG&E forecasts 25 full-time equivalent (FTE) employees to operate the Control Center on a 24-hour, 365 days-per-year basis. DRA recommends funding for only 21 FTEs, by comparing PG&E's Transmission Control Center

staffing. Based on the premise that the Distribution Control Center has twice as many consoles as the Transmission Control Center, DRA inferred that 21 positions, or twice the number of staff positions, were justified for the Distribution Control Center. PG&E claims that the distribution system is significantly larger in scope than the transmission system (e.g., over six times as many miles long), thus requiring more than twice the level of Control Center staffing. PG&E claims it cannot achieve the planned safety benefits with only 21 FTEs.

PG&E's staffing estimates reflect requirements for continuous around-the-clock operations. PG&E plans to use two 12-hour shifts per day, with shift rotations so that each employee's schedule averages out to 40 hours per week.

Over a 24-hour day, nine personnel are required to staff operator and coordinator functions on 12-hour shifts (i.e., six people on the day shift and three on the night shift). One operator will staff each of four regions and one coordinator per two regions per day shift. One operator will staff each of two regions and one coordinator per night shift). Adjusting for vacations, holidays, etc., each FTE works 1,580 productive hours per year. To staff the control room with nine 12-hour shifts per day for a year requires 39,420 (9 x 12 x 365) productive hours of labor, equal to 24.949 FTE positions (39,420 ÷ -1,580). After adjustment for productive hours work per position, the result is thus 25 FTEs to cover the full year.

DRA's witness agrees that to staff the control room as PG&E plans requires 39,420 productive hours. Mathematically, 21 FTE employees work 33,180 productive hours a year (21 x 1,580). This staffs only 7.5 shifts (33,180÷ 365 ÷ 12).

We conclude that to effectively operate the Control Center on a 24-hour basis at full capacity, PG&E's forecast of 25 FTE control center employees is reasonable and authorize funding for the positions as discussed below.

Clearance Personnel

PG&E forecasts an increase of $905,000 to fund one supervisor plus four clearance coordinators (one for each of four regions) to implement a new clearance process for field work. DRA opposes this increase, claiming that PG&E has not provided adequate support, and that PG&E should be (and has been) reviewing, approving, and coordinating clearances without the new Control Center. PG&E explains that the proposed staffing is for a new distribution clearance process that requires an increase in effort and focus. The new clearance procedure involves specified procedures and centralized control for scheduling and safety executing work.

3.2.1. System Operations Support

PG&E seeks funding of $724,000 for four Systems Operations support personnel, consisting of an engineer/supervisor, a senior quality engineer, a gas operations engineer, and a senior distribution specialist for training development and emergency response. DRA opposes funding, claiming PG&E provided inadequate justification. PG&E explains that these employees are required to provide "quality engineering and compliance including data quality control, process improvement, root cause analysis, benchmark, metrics, control room management requirements, compliance assurance, and training." We conclude that PG&E justified the need for the positions.

3.2.2. Technology Support Personnel

PG&E forecasts $1.629 million for nine gas control technology support personnel to create functionally appropriate gas Control Center application

software. DRA proposes limiting funding to three new positions since PG&E hired only 1/3 of the staff forecast for 2012. PG&E responds that slower-than-forecasted hiring during 2012 did not reduce overall staffing needs for nine Control Center support personnel during 2014. PG&E argues that funding for all of the nine technology support positions is required to ensure the proper function of the Supervisory Control and Data Acquisition (SCADA) system and to realize the benefits of the Control Center. We conclude that PG&E justified the need for all nine positions.

3.2.3. Contractor Support

PG&E forecasts $467,000 for contractors to supply employee training. DRA proposes to reduce funding for contractors by $126,000 based on actual 2012 costs. PG&E responds that 2012 costs do not reflect the level of increased training required during 2014 to maintain certifications and proficiency of operators.

PG&E forecasts three gas planning engineers assigned to the Control Center. DRA proposes one. PG&E argues that one engineer is not enough to cover continuous staffing shifts of 12 hours a day, seven days a week, 365 days a year. We conclude that PG&E has justified the need for additional training resources.

3.2.4. Distribution Control Center Capital Expenditures

PG&E forecasts capital expenditures of $220 million over the 2012-2016 period for MWC 4A to install remote monitoring instrumentation and control devices on its gas distribution system. PG&E planned to have the first branch of monitoring and control devices up and running by December 2012, and to add more control and equipment capabilities over the 2014-2016 GRC cycle. The

breakdown by year is as follows: 2012 – $4.447 million; 2013 – $24.851 million; 2014 – $62.209 million; 2015 – $63.008 million; and 2016 – $64.918 million.

For the 2012-2014 period, PG&E forecasts MWC 4A capital expenditures of $91.5 million. DRA proposes reducing PG&E's 2012-2014 capital expenditure forecast for MWC 4A by $59.8 million, arguing that PG&E may not complete the work as rapidly as planned. DRA's reduction is based on shifting PG&E's forecast for 2012 and 2013 out one year to 2013 and 2014, respectively. DRA relies on recorded 2012 capital expenditures for MWC 4A for its 2012 forecast. In view of delays in installations, excessive forecasts for 2012 and 2013, and the uncertain status of installations, DRA recommends shifting the forecast by one year. DRA's 2014 forecast of $24.851 million is equal to PG&E's 2013 forecast for MWC 4A. The comparison of the PG&E and DRA forecasts for MWC 4A, together with our adopted results, is summarized as follows:

$000s

Year	**PG&E Forecast**	**DRA Forecast**	**Adopted**
2012	$ 4,447	$ 2,420	$ 2,420
2013	$24,851	$ 4,447	$24,851
2014	$62,209	$24,851	$ 53,300
Totals	$91,507	$31,718	$ 80,571

PG&E claims that start-up delays and reduced spending during 2012 do not cause a reduction in 2014 forecasts. Lower-than-forecast expenditures for 2012 reflect a delayed start, but no change in scope, overall cost, or project end date.

PG&E experienced Control Center start-up delays during 2012, attributed to revised customer outreach in light of experiences with SmartMeter™ deployment. PG&E claims to have resolved this issue with a 95% success rate in

obtaining customer permissions. The delay in 2012 was also due, in part, to certain equipment testing that has now been resolved. PG&E decided to install more sophisticated devices. PG&E claims that the reasons for these delays have been resolved, and that 2013 spending is expected to be more than its forecast. PG&E still claims it can meet its 2014 forecast. PG&E argues that the Control Center cannot be constructed as designed to serve its intended safety function if DRA's reductions are adopted. If the 2012 forecast is reduced to reflect actual 2012 spending, PG&E claims a correspondingly higher prospective forecast of $18.8 million should be adopted to provide funding to complete the project.

Discussion

Our adopted capital expenditure forecast for MWC 4A to install remote monitoring instrumentation and control devices on its gas distribution system is summarized in the table above. For the year 2012, we adopt recorded spending as the 2012 forecast given the delays PG&E encountered. Since PG&E has overcome certain roadblocks that relate to 2012 delays, we conclude PG&E's forecast ramp-up in spending for 2013 is reasonable. Accordingly, we adopt PG&E's forecast for 2013. In order to complete the forecasted level of installations, PG&E will need to increase spending levels after 2013 to make up for the delays in 2012. We remain doubtful, however, that PG&E can realistically finish all planned installations of monitoring and control devices by 2014, particularly given the complexities and magnitude of work involved, and in view of the caveats in the Cycla Report as noted below.

While it is difficult to predict the rate of progress with absolute precision, we find it reasonable to adopt a more moderate level of estimated capital spending for 2014. The Cycla Report states that the Gas Control Center is "an extremely ambitious program and there are many roadblocks that could delay its

completion." One of the major uncertainties cited by Cycla is the software needed to integrate all of this data and present it to the control operators in a comprehensible form. (Exh. 167, Cycla Report, Attachment 6, page 3). To quantify this uncertainty, we apply the same percentage reduction in PG&E's forecast as we apply to other IT projects that were forecast using the Concept Cost Estimating Tool, as discussed in Sec. 7.8.2.7. Based on this 14% adjustment, we reduce PG&E's 2014 forecast by $8.7 million. The adopted 2014 capital forecast is thus reduced to $53.3 million.

We conclude that the remaining spending that PG&E forecasts on this program would occur after the test year.

3.3. Gas Distribution Mapping and Records

PG&E forecasts $16.2 million for gas distribution mapping activities (MWC GF), a $15.2 million increase over 2011 costs. The increase is due mainly to PG&E's records collection effort, comprising $14.1 million. PG&E maintains over 21,000 distribution maps depicting more than 42,000 miles of gas main and 3.3 million gas service lines. This information is maintained in disparate systems and paper records stored in local offices throughout PG&E's service territory. Funding is sought to collect, transport, standardize, and electronically archive over 15,000 linear feet of gas distribution paper as-built records[15] and gas service records into the enterprise wide records center.

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[15] "As-built" records are red-lined drawings of an asset installation associated with what was actually installed in the field, and includes drawings, material specifications, permits, purchase orders, and other relevant information regarding the installed condition of the asset.

PG&E also seeks funding to increase the number of mappers from 60 to 85. PG&E's goal is to have all mapping jobs posted within 30 days or less of being accepted by mapping. The Pathfinder Project and the Mapping Records Collection initiatives are intended to be implemented concurrently.

DRA has no objection to PG&E's efforts to collect, scan, and centralize maps and as-built records, but disputes PG&E's proposed project time-frame, scope of work, and cost. DRA recommends a reduction of $12.5 million in PG&E's forecast in MWC GF, including a reduction of $10.9 million for Mapping Records Collection and a reduction of $1.675 million for mapping headcount and associated expense.

DRA claims that (1) PG&E has only 10,000 -- rather than 15,000 -- linear feet of records to collect and scan, (2) there is embedded funding for the records collection work and (3) the timeframe of the records collection should be extended from 3.5 years to five years. DRA recommends $3.6 million for MWC GF consisting of $3.2 million to collect and scan 10,000 as-built records for the Pathfinder project and $424,000 for additional mappers. The DRA forecast of $3.6 million is $1.5 million, or 70%, higher than the 2012 recorded amount.

PG&E forecasts the costs to support the centralized records facilities spread over a 3.5-year period between 2013 and 2016. DRA recommends that this project be extended over five years, beginning in 2013. DRA claims that PG&E did not provide convincing evidence that collection and scanning of distribution pipeline documents needs to happen in the compressed timeframe similar to gas transmission. Due to the urgent need to validate the Maximum Allowable Operating Pressure of transmission pipeline, the proposed timeframe to complete the gas transmission automated mapping project was necessary as an immediate remedy. However, DRA claims that there is no similar urgency on

the gas distribution side. Therefore, DRA recommends that implementation of this project be spread out through 2018 to ease rate shock effects.

DRA also takes issue with PG&E's proposed project cost and disputes PG&E's methodology for calculating that 15,000 linear feet of records need to be converted. DRA claims PG&E has already collected and converted some of these records, thus reducing the linear feet of records yet to be retrieved, scanned, and managed. DRA claims that a figure of 10,000 linear feet should be used to calculate the scope of mapping work, taking into consideration PG&E's failure to provide the survey on which PG&E based its project scope. The 10,000 linear feet figure equals 41% of the 24,344 records PG&E identified as the combined linear feet of files.

DRA also argues that that PG&E has proposed data conversion projects for gas distribution assets many times in previous cases. PG&E claims that its survey of mapping records only included records not previously converted to electronic format and which were converted into linear feet.

Cycla identifies accurate maps and records as critical to many operational functions, and fundamental to PG&E's ability to characterize the risk of its system. Cycla believes the major potential constraint in the forecast is PG&E's ability to scale up from 60 to 85 mappers. PG&E claims, however, that all of the 85 positions were already filled in 2012, thus rendering moot the uncertainty issue.

PG&E argues that DRA's recommended reductions would delay implementation of efforts to increase public and employee safety, thus increasing the risk exposure of PG&E's distribution system.

DRA also recommends denial of PG&E's request of $1.3 million in contingency expense, arguing that PG&E identified no risks for this project

requiring a contingency fund. DRA also recommends a $1.7 million reduction to PG&E's $2.1 million forecast to perform base work and to eliminate a purported backlog. The reduction eliminates a 14.81% increase in base level costs which DRA states is unjustified together with an adjustment to base year costs to reflect an error in base cost allocation between electric and gas distribution departments.

Discussion

We conclude that funding for PG&E's Gas Distribution Mapping and Records project should be approved. The need to maintain a central repository of accurate up to date records and maps to support safe gas distribution asset management justifies the project. As noted by Cycla, inaccurate location information is a significant contributing factor to excavation damage, which is the largest contributor to PG&E's distribution system risk. Centralization of the documents will also provide faster and more efficient means of information sharing.

We accept PG&E's estimate of 15,000 linear feet of gas distribution paper as-builts and gas service records to be collected, transported, standardized and electronically archived. PG&E estimated that 30,000 records total for gas and electric departments, and allocated 50% to gas distribution. DRA's alternative estimate of 10,000 feet is premised on the belief that PG&E has already collected and converted some of these records. As PG&E explains, however, its prior record conversions did not involve gas distribution as-built, and embedded funds do not include a provision for such conversions. In view of the fact that PG&E's forecast was done on a bottoms-up basis, we conclude that forecast reflects only incremental activities not covered in existing embedded rates. Cycla concludes that PG&E's forecasting approach for distribution mapping and

records was reasonable and that forecasted expenditures were not grossly overestimated.

We also conclude that PG&E's proposed implementation time frame for the Mapping Records and Collection effort is reasonable as it coincides with Pathfinder Project implementation. Extending the schedule for records collection and mapping, as proposed by DRA, could delay implementation of Distribution Integrity Management Program (DIMP).

We reduce PG&E's MWC GF forecast of mapping and records collection, however, to remove $1.3 million in contingency expense. PG&E has not identified any unusually difficult factors in forecasting that warrant burdening ratepayers with funding of the $1.3 million contingency amount for this program.

We also note Cycla's concern that PG&E provided no analysis of alternative approaches to increased staffing from 60 to 85 in-house mappers, such as using outside contracting, nor was a productivity factor applied to forecast staffing. Cycla states that the justification is also unclear as to the need to retain the 85 mappers once the backlog is cleared up, and that justification is needed to retain the 85 mappers to support a 30-day mapping update cycle as well as to support the Pathfinder project. Cycla proposes that the costs associated with hiring the 85 mappers be attached to a two-way balancing account to ensure the funds are expended for their stated purpose. (Cycla, Attachment 6 at 7).

In view of Cycla's concerns regarding the increase in mappers from 60 to 85, we conclude that the forecast of 85 mappers may be excessive. Accordingly, we reduce the requested funding to cover only 80 mappers, representing a 10% efficiency reduction in the requested increase. We also require PG&E to provide

in the next GRC an accounting of the continued need for or use of the additional mappers once the mapping backlog is cleared up, including documentation that authorized funds were expended for their intended purpose.

DRA proposes a $970,000 reduction to PG&E's forecast claiming that PG&E incorrectly assumed $970,000 in recorded expense in 2011, when the 2011 recorded expense was $0. DRA claims that PG&E recorded $0 to MWC GF in 2011 because PG&E's original workpapers, later corrected in errata, showed zero. PG&E's opening testimony showed the correct amount – $970,000. PG&E explained the workpaper correction in rebuttal testimony. Thus, we find no basis to reduce PG&E's forecast by $970,000, as DRA proposes.

3.4. Gas DIMP

PG&E's Gas DIMP is designed to comply with federal regulation and enhance safety by identifying operational threats and reducing pipeline leak risks by mitigating risk factors such as corrosion, natural forces, excavation damage, other outside force damage, material, weld, or joint failure, equipment failure, and incorrect operation.

PG&E forecasts 2014 DIMP expense of $47.253 million (MWC JS) to comply with federal pipeline safety requirements, and enhance safety and system reliability. The 2014 forecast is $22.6 million higher than the 2011 levels, a 91.5% increase. DIMP expenses relate to: (1) the Cross-Bored Sewer Project; (2) identification of Aldyl-A pipe to be replaced; (3) the Plastic Tee Cap Repair; (4) Leak Survey; (5) Corrosion Mitigation, (6) other emergent work; and (7) additional staff to support DIMP management and Cycla concludes that PG&E's proposed DIMP scope and staffing appear consistent with high-performing operators. Cycla finds that PG&E provided justification for associated improvements in DIMP management, and that PG&E's overall

estimated funding level approach for identified risk reduction measures was reasonable and forecasted DIMP expenditures were not grossly overestimated.

DRA recommends a DIMP forecast $35.2 million lower than PG&E's request. PG&E versus DRA and TURN proposed differences are compared below:

$ in 000s

	Forecast	Proposed Reductions	
	PG&E	DRA	TURN
Leak Survey Enhancements	$1,971	-10	-1,971
Cross-bored Sewer Project	$14,458	-12,478	-8,456
Program Management	$13,560	-10,742	-7,862
Emergent Work	$10,000	-10,000	-5,473
Miscellaneous	$7,264		
Total	$47,253	-35,191	-24,739

We resolve these disputes as discussed below.

3.4.1. Leak Survey Enhancements

PG&E forecasts $1.97 million for annual leak surveys of 1,000 clusters in 2014, totaling 57,000 services annually, representing 1.7% of PG&E's distribution system. Expense for this work is forecast in MWCs JS, DE and FI. PG&E forecasts the incremental cost of this work using the Picarro Surveyor (lower leak survey costs and higher leak repair costs).

DRA recommends no funding for Leak Survey Enhancements, arguing that funding is already embedded in MWCs DE and FI (p. 36 lines 21-22). PG&E denies that embedded funding covers new work. PG&E deducted amounts forecast in MWC JS for survey and repair from the MWCs DE and FI forecasts. DRA agrees with allowing $500,000 for program management cost relating to

creating leak cluster survey packages, transferring leak cluster maps onto plat sheets, review of leak data, defining the extent of the leak survey, packaging maps and supporting documents and analyzing and documenting the program.

DRA argues that PG&E should annually survey only 163 clusters, rather than the 1,000 clusters PG&E forecasts and which translate into 57,000 services based on clusters surveyed in 2012. PG&E used the number of clusters surveyed in 2012 to derive the 2014 forecast. A leak cluster is a collection of repaired leaks with a 100 foot radius buffer around the leak.

TURN recommends that the enhanced leak survey program be integrated with traditional leak survey and repair and that no incremental ratepayer funding be authorized for this program. PG&E responds that there is no existing funding available in MWCs DE or FI for this proposed work.

Discussion

We approve PG&E's forecast of $1.971 million for enhanced leak surveys. We conclude that PG&E's forecast is reasonable and covers new activities that are incremental to the leak survey work currently funded in rates.

We approve PG&E's proposed funding level to cover recheck of Grade 3 leaks within 15 months rather than waiting for the next scheduled survey cycle. During oral testimony, PG&E provided data showing that about 1.6% of Grade 3 rechecks during 2007-2012 resulted in a reclassification of the leak to Grade 1. Based on this information, TURN does not oppose PG&E's proposal to accelerate Grade 3 rechecks as long as a five-year survey cycle continues. However, if a three-year survey cycle is authorized, TURN recommended that Grade 3 rechecks not be accelerated further. TURN's proposal would reduce test year funding by $3.14 million.

We disagree with DRA's assumption that PG&E's pipe replacement program will eliminate the need for annual cluster surveys. With 42,000 miles of pipe, planned pipeline replacements will not be sufficient to eliminate the need for the annual cluster survey during 2014-16. Pipe that has been replaced or is scheduled for replacement is not part of the annual cluster survey.

3.4.2. Cross-Bore Sewer Remediation Project

PG&E forecasts DIMP expense of $14.458 million in 2014 to perform engineering review and inspection of 30,000 sewer lines and to repair 500 cross bores, with $3.2 million for engineering review, $7.5 million for inspections and $3.8 million for remediation. Cross-bores occur when a service line pipe is installed using directional boring through a sewer line. Cross-bores pose a substantial safety risk.

DRA and TURN recommend reducing PG&E's cross-bore forecast by $12.478 million and $8.456 million, respectively. DRA's 2014 forecast is comparable to PG&E's 2012 expense. DRA characterizes PG&E's cross bore project scope to inspect 500,000 services over 10 years and 30,000 in 2014 as excessive and unsupported. DRA recommends no funding for engineering review to identify locations to be inspected and funding at 2012 levels of only 6,000--rather than 30,000--annual inspections as PG&E forecasts.

DRA's forecast is based on a unit cost of $5,000 per cross-bore repair, which is a blend of $3,015 for below ground service repair and $6,016 for mains repair. DRA claims that PG&E's assumed unit cost of $6,016 is based on the cost for mains repair, which is the most expensive form of repair. DRA also proposes that PG&E combine its cross-bore inspection and remediation with its pipeline replacement and repair activities to improve overall work efficiency.

TURN recommends that PG&E continue at the 2012 level of effort (i.e., 10,000 inspections and 200 repairs), while conducting research on cross-bores risk and refining the method for identifying where cross-bores may have occurred.

Given the cost of required video inspections, TURN believes more precisely targeting the inspections would increase cost-effectiveness, give a more precise estimate of work, and accelerate elimination of cross-bores. TURN claims that PG&E has not adequately identified the risks and inspections required.

Discussion

PG&E's cross-bored program mitigates a major risk by identifying where cross-bores may have occurred, and, if so, relocating the line. Cleaning a sewer line can sever the gas line, causing gas to migrate into a home or other building. As noted by Cycla, PG&E's forecast cross bore program scope is "consistent with practices employed by best operators, especially by addressing a major potential risk associated with intersecting gas lines and sewer pipes."[16]

We adopt PG&E's forecast for cross-bore remediation, adjusted to reflect the lower unit cost of $5,000 calculated by DRA, instead of the $6,016 reflected in PG&E's forecast. The $5,000 unit cost is a blend of $3,015 for below ground service repair and $6,016 for mains repair. The $5,000 unit cost is a more accurate measure relative to PG&E's figure.

We conclude that PG&E's estimate of engineering review and inspection of 30,000 sewer lines and repair of 500 cross bores is reasonable. PG&E's forecast is a significant increase over earlier years, reflecting a repair rate of 1.67% to 2% of

[16] Ex. 167 (Cycla Report) at 36.

the sewer laterals inspected, although the average repair rate for 2011-12 was only 0.65%. PG&E experienced an even lower actual repair rate of 0.41% for 2011 and 2012.

PG&E appears capable of ramping up to achieve 2014 forecast levels, however, and expects to complete 25,000 inspections in 2013, which is 14,000 more than TURN's estimate for 2014. DRA's forecast based on the work scope experienced during 2012 doesn't reflect the 2014 increased work scope.

PG&E has been working to identify cross-bores since 2009, and began to check bore holes for copper service replacements in 2010. PG&E did not undertake analysis on the risk of incidents in its 2011 GRC. In late 2011, PG&E initiated broader inspection to ensure that new cross-bores were not created. PG&E conducts records research to ensure inspections occur only in locations where a cross-bore risk exists.[17] We also direct PG&E to assess whether it would be more cost effective to combine its cross-bore inspection and remediation with its pipeline replacement and repair activities to improve overall work efficiency.

We are not persuaded to deny recovery of PG&E's costs to inspect and remediate mains and services installed after 2007. DRA claims that PG&E was aware of the cross-bore problem in 2007, but did no video inspections during those installations. PG&E explains, however, that it was only beginning to evaluate the risk of cross-bores, and had not yet developed video inspection techniques in 2007. We find no basis to disallow cost recovery for cross bores based a standard for video inspections that did not yet exist in 2007.

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[17] Ex. 53 at 4-21, lines 21-26.

3.4.3. Program Management

PG&E requests $13.56 million for program management consisting of $4.5 million for internal management resources, $1.4 million for contracted engineering and reporting support, $0.1 million for vault dewatering, $0.1 million for committee expenses, and $7.3 million for plastic tee cap repair.

PG&E's Program Management expense includes $4.5 million to increase DIMP staff responsible for scoping and planning program projects and programs identified by PG&E's risk algorithm and Threat Committees. PG&E forecasts staffing increases growing from nine positions (in 2011) to 20 positions in 2014. The additional headcount consists of a Director of DIMP, a manager for engineering, a manager for Gas Distribution Asset Engineering, three supervising engineers and five staff engineers.

DRA recommends using 2012 recorded expense of $2.3 million as the 2014 forecast arguing that most of PG&E's forecasted program activities are already in place. DRA recommends no ratepayer funding for contract support arguing that PG&E has $0.6 million in embedded funding. DRA accepts PG&E's forecast of $0.5 million for miscellaneous expenses.

TURN recommends limiting Program Management spending to 2012 levels, calculated as $3.354 million. PG&E claims that TURN is conflating an additional work category to derive this figure. As a basis for its forecast, TURN utilizes program management, data collection and risk assessment costs estimated by the Pipeline Hazardous Materials Safety Administration (PHMSA) to assess the costs to meet the requirements of federal DIMP regulations. In order to apply the PHMSA estimates to PG&E, TURN adjusted the PHMSA forecast to account for PG&E's relative size as a utility and San Francisco Bay area labor costs. Since the PHMSA costs were based on 2004 data, TURN applied

escalation to inflate costs to 2014 dollars. TURN took the PHMSA high-end estimate, as adjusted, and recommended authorization somewhat above the resulting number. TURN argues that PG&E's costs far exceed PHMSA forecasts and reflect attempts to develop new models without first understanding and analyzing outputs of prior models. TURN claims PG&E's risk assessment and management forecasts are duplicative and lack coordination. PG&E's forecast is over four times above PHMSA estimates (as adjusted for date and utility size). TURN argues that PG&E needs to use existing information in a more coordinated effort, and streamline its planning organizations, rather than to develop more sophisticated models.

Discussion

We adopt PG&E's forecast for Program Management expense of $4.5 million. We conclude that the Program Management positions forecasted by PG&E are needed to manage the anticipated growth in the volume of work as additional risk mitigation measures are identified. We conclude that 2012 recorded costs do not reflect the full annual cost of employees hired in 2012, or annual wage escalation through 2014, nor costs of staff hired in 2013. PG&E developed its staffing plan in mid-2012 and only started hiring in 2012. PG&E filled 11 of the forecasted 20 positions in 2012, and expected to fill the remaining positions in 2013. The 2014 forecast reflects the staffing level already expected to be filled by the end of 2013.

We decline to reduce PG&E's forecast based on PHMSA data. The empirical basis of the PHMSA data has not been sufficiently documented as suitable for use in setting 2014 revenue requirements for PG&E's Program Management. PG&E challenges PHMSA cost estimates, arguing that federal government cost estimates have a history of significantly under estimating

implementation costs. Although TURN utilized PHMSA's "high" estimate, and increased that estimate by more than a factor of 10 to account for PG&E's size, and adjusted for local cost and price inflation, we find too many uncertainties as to the empirical validity of the 2004 PHMSA study for use as a proxy for forecasting PG&E's 2014 Program Management costs.

3.4.4. Emergent Work

PG&E requests 2014 funding of $10 million in expenses for activities identified as Emergent Work, representing miscellaneous DIMP projects not yet specifically identified. Based on continuous evaluation of system threats and resulting risk mitigation measures, PG&E expects that additional risks will be identified that will need to be mitigated, in addition to risks already identified. DIMP is intended to identify and address risks to the distribution system.

PG&E identified miscellaneous work activities in 2011 but did not include them in time for the 2011 GRC filing. The work activities identified are Low Pressure Vault Dewatering ($0.2 million), Low Pressure Vent Raising ($2.9 million), Plastic Leak cluster survey ($0.5 million) and integrity management corrosion mitigation ($0.7 million). The total expense identified for all these projects is $4.3 million above and beyond the 2011 to 2013 level. PG&E uses these examples to show it incurred unanticipated costs between rate cases. These projects are examples of miscellaneous activities that PG&E had to address in 2012 and in 2013 and to support its 2014 request for on-going miscellaneous projects.

DRA recommends no ratepayer funding for DIMP Emergent Work, arguing that PG&E has not identified any specific projects for 2014 nor adequately supported the request for $10 million. DRA requested the 2012 recorded expenses for Emergent Work and found that the amount was zero as of

September 2012. DRA notes PG&E requested funding in the past for DIMP programs that it subsequently abandoned. PG&E claims that providing no funding for emergent work essentially puts the DIMP on a three-year delay, providing funding only for known mitigation measures to known threats. PG&E argues that if reallocation of existing resources is the only method for mitigating new risks, the effectiveness of DIMP is limited.

TURN recommends $4.7 million funding for Emergent Work which is the amount that PG&E identified for project costs between 2011-2013 that were not embedded in rates. TURN states that PG&E only looked for additional funding opportunities and failed to consider evaluating the effectiveness of the efforts already selected, or to look for reallocation of existing funds.

Discussion

We conclude that a reasonable level of funding is appropriate to cover contingencies for DIMP emergent work that is not yet specifically identified. One purpose of the DIMP is to identify new system safety risks and resulting new mitigation measures. PG&E is conducting root cause analysis to identify additional mitigations as part of Emergent Work. The first of these analyses has been completed and mitigation plans are in development. PG&E expects to identify new work that needs to be done as a result, but doesn't yet know what the specific work will be. As PG&E completes a full DIMP cycle, additional work could be identified. PG&E seeks funding to perform such emergent work.

While funding for emergent work at a reasonable level is warranted, PG&E fails to justify a revenue requirement of $10 million. PG&E states that the $10 million represents an estimate of additional work that will result from continuous evaluation of the threats to PG&E's gas distribution system and implementation of risk strategies…and…any unanticipated changes in scope for

the existing programs under Integrity Management. Without further empirical support justifying such a large increase over prior levels, we find insufficient basis to burden ratepayers with increased funding as high as $10 million as requested by PG&E for emergent work.

We conclude that TURN offers a reasonable approach, proposing some funding, but not the full $10 million proposed. We thus approve Emergent Work funding of $4.7 million for 2014, equal to costs incurred between 2011 and 2013 that were not included in the 2011 GRC forecast. If 2014 costs for emergent work exceed our authorized contingency allowance, PG&E should consider ways to reprioritize work, or reallocate funds as warranted at the time, to meet its DIMP responsibilities.

3.4.5. Tee Cap Replacement (MWC JSL)

PG&E forecasts $7.3 million in 2014 (in MWC JSL) to identify areas with clusters of plastic tee caps and to proactively repair them to prevent future leaks. Plastic tee caps are the primary source of leaks associated with Aldyl-A plastic pipe. The forecast will fund repair or replacement of up to 1,000 tee caps a year. Identification of tee caps is job specific and will use a leak cluster model to identify where leaks exist in a given area of pipe.

DRA recommends no new funding for tee cap repair in 2014 arguing it is not a newly identified risk. DRA claims that PG&E has no basis for estimating 1,000 tee caps to be repaired. TURN supports the Tee Cap program on a pilot basis, but proposes that tee cap repairs be integrated into capital funding for pipe replacements, with no new revenue requirement funding. TURN supports including tee cap repair costs as part of a two-way balancing account for pipe repair.

Discussion

We adopt PG&E's forecast of $7.3 million for the program to identify areas with plastic tee caps and to proactively repair them to prevent future leaks. This program mitigates a known safety risk. Proactively fixing tee caps at risk for potential leak is more efficient than fixing them one at a time when discovered during a routine survey. This eliminates the risk of that leak causing damage or personal injury.

We conclude that incremental funding is thus warranted as this is a new pilot to determine the best way to do proactive repair and establish training and work procedures. Existing rates do not include funds for proactive repair before leaks appear. The tee cap pilot program is not designed to determine whether the work should be done, but only how to implement the work. We conclude that PG&E's estimate for 2014 is reasonable given its record of repairing 10,000 tee caps since 2008 as part of normal leak repair work in MWC FI.

PG&E does not discuss tee caps as a consideration in pipe replacement, nor include the tee-cap effort in estimates of pipe replacements to meet leak rate goals. PG&E makes no connection between this program and the DIMP Leak Survey Enhancement program. While the initiatives coming out of the DIMP risk management process should inform PG&E's activities and risk reduction focus, there is no indication that PG&E has used its experience to integrate its knowledge of the tee cap issue with other risk reduction initiatives. The results of this pilot program should enable PG&E to integrate its knowledge and help reduce pipeline leak risks.

We conclude that tee cap repair costs are correctly categorized as an expense. It thus would be improper to fund the tee cap repair costs through capital accounts as part of pipeline replacement, as proposed by TURN.

In order to provide added assurance that authorized funds are spent for the designated purpose and that any unspent funds are duly identified, we direct that actual tee-cap repair costs be tracked and included for future disposition in the authorized leak repair balancing account. Differences between authorized and actual expenditures for this work activity will be subject to true up in the next GRC.

3.4.6. Balancing Account Proposal for DIMP

PG&E currently has a one-way balancing account for DIMP costs, adopted in the last GRC. DRA proposes implementation of a two-way balancing account for DIMP work tracked under MWC JS, capped at PG&E's 2011-2012 average expenses of $25.6 million. The two-way balancing account would provide a cost recovery vehicle in the event that PG&E needs to perform more DIMP work than anticipated and incurs more expense than forecast. If PG&E spends more than the cap, it could reallocate resources from other activities to cover the excess and request a higher level of costs in its next GRC.

PG&E opposes DRA's proposed cap and balancing account proposal, arguing that it would be a reversal in the work done to support DIMP. PG&E argues that the proposed balancing account is not really a two-way, but is one-way. Based on DRA's proposal for a $25.6 million cap, PG&E complains that it would have to scale back its program to a level below 2012 recorded costs. The purpose of a two-way is to allow for needed funding to mitigate risk. PG&E claims the cap nullifies this benefit.

We decline to approve balancing account treatment for DIMP costs for the 2014 GRC, either on a one-way or two-way basis. As noted by PG&E, the DIMP balancing account treatment was implemented in the 2011 GRC at a time when the DIMP was new. The DIMP has now become more established, and its costs

can reasonably be estimated without the extraordinary requirement for balancing account treatment. PG&E shall remain responsible for managing DIMP costs without the protections of—or constraints of—a balancing account.

3.5. Pipe, Meter and Other Preventative Maintenance (MWC DF, FH, DG, EX and GM)

3.5.1. Introduction

PG&E forecasts $83.825 million in 2014 expense for Pipe, Meter, and other Preventive Maintenance which is designed to forestall equipment degradation and failure and promote a safer gas distribution system. Preventative maintenance includes locating and marking facilities for third parties, Cathodic Protection (CP), regulator station maintenance, main and service maintenance, valve maintenance and replacement, AC monitoring and remediation, meter protection, and natural gas vehicle maintenance.

DRA recommends a reduction of $14.537 million for Pipe, Meter and Other Preventative Maintenance forecast. DRA's recommendation is based on a lower forecast for Locate and Mark activities associated with USA tags and adjustments to PG&E's proposals for MWC FH such as a dedicated painting crew, AC Monitor and Correction, and Special Projects. DRA also recommends a reduction of $0.2 million, a 98% reduction, to MWC 27 for Capital Meter Protection in 2014.

Cycla comments that PG&E's projected increase in construction and infrastructure for this cost element is very uncertain.

3.5.2. Locate and Mark Underground Facilities (MWC DF)

PG&E forecasts $39 million for MWC DF (Locate and Mark) which involves locating and marking buried facilities prior to excavation by builders

and others planning excavation. Locate and mark activities reduce damage to underground facilities caused by accidental dig-ins. PG&E's forecast includes funding for an upgrade of software used to locate assets in the field, and providing field personnel more accurate information, while remaining compatible with mapping, records and GIS improvements. PG&E's forecast is also based on the estimated number of work orders, or "Underground Service Alert" (USA) tickets, to locate and mark gas distribution facilities. Key drivers for the increase over 2011 spending are the projected increase in the number of Locate and Mark requests and a new dedicated painting crew.

DRA recommends reducing PG&E's Locate and Mark (MWC DF) forecast by $5.160 million. DRA applies the recorded 2012 growth rate of 6% to 2013 and 2014 forecasts, and continued use of a 60% work rate from 2010, arguing that PG&E's claim of a higher growth rate is based on year-end 2012 numbers for which have no referenced support.

The 2014 forecast differences between PG&E and DRA, and our adopted results are as follows:

	$000s		
Item	**PG&E**	**DRA**	**Adopted**
No Maintenance Activity Type	$1,141	$818	$1,141
Locate and Mark	$36,796	$32,554	$36,796
Locate and Mark Standby	$1,111	$516	$1,111
Total	$39,049	$33,888	$39.049

DRA claims that PG&E lacks support for its forecast for items with Maintenance Activity Type. DRA relies on 2011 recorded expense, and claims that PG&E lacks support for its Locate and Mark forecast based on the number of USA tickets estimated for 2014. DRA argues that PG&E's forecasted 12%

increase in Locate and Mark requests from 2012-2013 and another 12% increase from 2013-2014 is excessive. DRA's forecast incorporates the 2012 number of USA tickets received, which is higher than the base year. DRA also argues PG&E has not supported its Locate and Mark Standby expense, and opposes PG&E's request to perform spot checks.

PG&E claims DRA ignores evidence explaining the work being proposed, why it is important and how much it is expected to cost. PG&E argues that DRA selectively uses 2012 recorded data only where it exceeds the forecast. PG&E claims that DRA's methodology would underfund system maintenance and adversely impact the ability to provide safe and reliable natural gas distribution service.

Discussion

We adopt PG&E's MWC DF forecast for Locate and Mark expense of $39.049 million for 2014. PG&E's forecast reflects reasonable increases in pre-excavation requests for Locate and Mark services and growth in northern California construction activities. PG&E's forecasts of increased activity levels in 2014 are based on a reasonable methodology. Cycla observes that PG&E's projected number of locates "may be a little high," but that PG&E "should have reasonably accurate projections."[18]

PG&E's forecast relies on the third-party economic analysis to forecast New Business (NB) and Work at the Request of Others within MWC 29. Forecasted growth rates are based on Moody's Investor Service and IHS Global insight, which projected growth rates of 9% and 0.6% in 2012, 53% and 13% in

[18] Exhibit 167, Cycla Report at 45.

2013 and 62.5% and 8.9 % in 2014. PG&E applied its own judgment to translate these estimates into an increase in USA tickets of 5%, 12% and 12% in 2012, 2013 and 2014, respectively. For 2012, PG&E experienced a 26% increase in USA tickets, rather than the 5% forecast. Overall, PG&E spent $4.9 million more than forecast on Locate and Mark activities in 2012 and over $1.4 million more than forecast on other preventative maintenance. In view of these results, we find PG&E's estimate of the level of activity for 2014 to be reasonable. The adopted funding is warranted to support PG&E's ability to promote system safety.

We also adopt PG&E's forecast for Locate and Mark Standby expense of $1.111 million as reasonable. Standby work funding covers the process for an employee presence at the work site to ensure the safety of crews and the general public while the excavation near a critical PG&E asset is occurring. The increased funding over 2011 levels is to cover a "repeat offender" program to address the risk of contractors with a history of digging outside of delineated areas.

3.5.3. Gas Distribution Preventive Maintenance (MWC FH)

PG&E forecasts $28.3 million for gas distribution pipeline preventive maintenance (MWC FH) covering: (1) regulator stations, mains and services, and distribution valves, (2) service valve replacement, (3) AC, and (4) special projects. The forecast reflects paint crews and low vent elevation reconstruction to mitigate risks of over-pressurization of the gas distribution system caused by flooding. To maintain the mandated three-year AC inspection cycle, PG&E forecasts expenses to supplement a five-year leak survey inspection frequency if the Commission does not approve a three-year leak survey cycle. If the Commission adopts a three-year leak survey, the AC inspection forecast would

be lower since PG&E can achieve some costs savings by combining leak survey and AC inspection.

DRA recommends a reduction of $9.043 million in PG&E's forecast for MWC FH, based on the following differences between PG&E and DRA:

	($000s)	
Item	PG&E	DRA
Projects with no Mat Code	$4,368	$1,285
Special Projects	$4,356	$1,663
Atmospheric Corrosion	$4,737	$1,469

DRA opposes increased ratepayer funding for PG&E's plans to hire 15 new painters, perform AC meter inspections every three years, implement the Picarro Surveyor, and the unit cost used for low-pressure vents.

TURN recommends reducing PG&E's Preventative Maintenance forecast by $3.783 million.

We resolve these disputes below.

3.5.3.1. Dedicated Paint Crew and other Projects with no Maintenance Activity Type (MAT) Code

PG&E requests $4.368 million under subaccount MAT-NA for preventive maintenance not associated with a specific MAT code. This includes an increase of $3.5 million over 2011 amounts of which $3.1 million covers painting of all above-ground distribution assets. The forecast assumes 15 workers performing 24,000 hours of painting per year, an increase of 23,257 hours over 2011 levels. PG&E plans to deploy dedicated paint crews throughout the service territory to combat AC of above ground assets through a more comprehensive program than in the past. DRA recommends no new funding for this work activity, arguing

that PG&E did not support the increased spoils removal costs and that PG&E has embedded funding for painting above-ground assets. DRA claims that PG&E failed to show that a problem exists with the current process of painting assets used by PG&E employees and contractors.

PG&E agrees it did not support increased spoils removal costs and agrees to a $333,370 reduction of its forecast. PG&E denies, however, that embedded ratepayer funding is available for this project which supplements and enhances existing painting projects, is more comprehensive than past efforts, and requires more resources to combat AC than funded previously.

Discussion

We concur with PG&E's assessment that its plans to deploy additional paint crews to combat AC will extend asset life in a proactive manner. We conclude that embedded funding is not sufficient to cover the increased scope of work and that PG&E's forecasted increase in the scope of work is appropriate. The enhanced painting will combat AC and extend asset life. PG&E plans to deploy the dedicated paint crews throughout its service territory through a more comprehensive program than in the past, with a greater investment in time and materials to allow for better surface preparation, higher quality paint, and an integrated inspection and repair program. We adopt PG&E's 2014 forecast of $4.368 million for No Mat Code projects, which incorporates the reduction of $333,370 for spoils removal costs.

3.5.3.2. Atmospheric Corrosion (AC) Monitoring

PG&E forecasts $2.837 million for AC inspection and remediation, based on a three-year leak survey cycle, or $4.737 million (as shown in the Joint Comparison Exhibit) assuming a five-year leak survey cycle. PG&E is required to perform AC inspections of above-ground assets every three years. On a

three-year leak survey cycle, PG&E claims that leak surveyors would be able to perform this inspection work and thus save $1.9 million.

Historically, this inspection work was performed by meter readers. With deployment of SmartMeters™, this is no longer possible. In 2011, PG&E employed contractors to perform this work and recorded $8.2 million to MWC JS, in addition to the $1.5 million recorded to MWC FH.

DRA takes issue with a $2.5 million increase to meet a three-year frequency cycle for AC meter inspections. DRA recommends $1.5 million.

PG&E argues that DRA's recommendation is based on only 2011 recorded costs in MWC FH, but ignores additional amounts recorded in MWC JS. PG&E seeks to recover AC inspection costs through its proposed two-way balancing account for leak survey and repair so it can continue to fully recover mandatory AC inspection costs as the Picarro Surveyor is deployed in more divisions.

Cycla remarks that PG&E's AC program forecast seems high and that having a dedicated group to do the program work may not be as cost effective as having other groups assigned the work, especially if they are nearby or doing the inspections.

Discussion

We adopt PG&E's forecast for AC inspection of $4.737 million based on the assumption of a five-year leak survey cycle. We authorize PG&E to track its AC inspection costs through the two-way balancing account to be implemented for leak survey and repair costs. To the extent actual costs differ from the adopted levels, PG&E shall provide the appropriate accounting and ratemaking proposals for disposition of funds in the balancing account in the next GRC. In reviewing disposition of balancing account costs in the next GRC, we expect PG&E to make

a showing regarding its efforts to perform this work most cost-efficiently, in line with Cycla's recommendations.

3.5.3.3. Low Pressure Regulator Vent Raising (MAT FHJ)

PG&E requests $356,000 for "routine special projects comprised of emergency and unforeseen work" and $4 million in expense for a new project to raise the height of low elevation vents and thereby reduce the potential for over pressurization.

PG&E has two programs to mitigate the risk of vault flooding: (1) the dewatering program forecast in connection with the DIMP; and (2) the program to raise equipment vents. The first program involves pumping water out of the vaults at scheduled intervals. This program has been effective so far, but it is not a permanent and 100% effective solution. Water intrusion, caused primarily by weather, can be irregular, and flooding can occur between scheduled dewatering activities. PG&E's program to raise the equipment vents, in contrast, is permanent and 100% effective. PG&E is also proposing to install SCADA monitoring and control equipment on each low pressure regulator station which will allow remote control of the pressure regulator in the event of any over pressurization event. PG&E also plans to completely eliminate its low pressure regulators over time. PG&E proposes to phase out vault dewatering by implementing the more permanent solution of lifting the vents, at a capital cost of almost $10.0 million.

DRA recommends a reduction of $2.69 million for PG&E's vent elevation project. DRA's revised cost of $1.7 million is based on PG&E's unit cost per low pressure vent location amount multiplied by 63 locations per year. DRA based its calculation on the number of stations, rather than the number of equipment

vents. The corrected forecast for a five-year program would thus be $2.4 million, not $1.7 million.

In 2012, PG&E initiated a pilot program to dewater vaults in the San Francisco and East Bay divisions on a more regular basis and keep track of the vault condition. The pilot dewatering program showed that only 21% of vaults experienced water intrusion problems, and 80% of the vaults had no water intrusion problem. In view of this data, TURN recommends: 1) raising only the 20 vents located in low pressure regulator vaults with significant water accumulation problems, and 2) continuing the scheduled vault dewatering program, resulting in a reduction of $3.783 million in account.

TURN claims there is no safety reason for lifting 360 other vents just to address a supposedly critical problem that has been addressed at low cost for thirty plus years. TURN denies that rapid lifting of the vents is a critical safety issue, since PG&E lifted none of the 141 vents it forecast for 2013. TURN believes the combination of scheduled dewatering, SCADA installation and low pressure main replacement provide a safe and more cost effective solution to potential vault water intrusion.

PG&E will, over time, replace the low-pressure vaults in which the low-pressure equipment vents are located, but since the replacement program will occur over a 40-year period, it would leave over-pressure risk unmitigated too long.

Discussion

We adopt PG&E's forecast cost of $4 million for the proposed new project to raise the height of low elevation vents and thereby reduce the potential for over pressurization. If a vent gets submerged in water, it can cause a low-pressure regulatory failure and thus an over-pressure event. While this is a

low probability event, its occurrence has potentially high consequences. Vault flooding applies excessive pressure to the diaphragm of a gas pressure regulation device and can release high-pressure gas into a low-pressure system. This compromises the integrity of downstream equipment and can cause a pipe rupture or other gas excursion that could damage property or cause personal injury or loss of life.

PG&E's past practices in mitigating this risk is no basis for continuing the status quo going forward. PG&E's rate case forecast called for lifting 230 vents in 2012-13, so that the program would be completed by 2014. However, few vents were lifted in 2012- 2013 because given what PG&E characterized as the dynamic nature of the work. The resources that would have performed that work were redirected to other work deemed by PG&E to have higher priority. PG&E has not evaluated the relative cost effectiveness of dewatering, SCADA installation or vent lifting.

Consistent with our focus on safety and risk mitigation in this GRC, we believe a more proactive solution is warranted going forward. Pumping water out of vents at scheduled intervals, while effective so far, is not a permanent solution. PG&E argues that over-pressurization risk would remain too long by relying on a replacement program which would extend over a 40-year period. Accordingly, we approve PG&E's funding amount to permanently and expeditiously mitigate this risk, which will also reduce the need for the dewatering program. We also approve PG&E's requested funding for $356,000 for routine special projects, which no party argued is unreasonable.

3.5.3.3.1. Gas Meter Protection (MWC 27)

PG&E forecasts $1.027 million, $1 million, and $246,000 in capital expenditures for 2012, 2013, and 2014, respectively for the Gas Meter Protection

Program. This program remediates meters that have inadequate protection from vehicle damage or inaccessible service or shutoff valves. Historically PG&E has deemphasized this work in favor of higher priority work.

DRA recommends limiting the Meter Protection forecast to $5,000 per year, in line with PG&E's 2012 spending levels.

We adopt PG&E's forecasted 2012-2014 capital expenditures for Gas Meter Protection. The fact that PG&E has not given this program higher emphasis in past years does not provide a basis to continue past practices by default. Cycla found that PG&E's forecast scope of work for gas meter protection is "consistent with practices employed by best operators" and that PG&E's forecast staffing is "consistent with [the] forecast work activity." In the interests of providing sufficient funding for PG&E to achieve best industry practices, we conclude that PG&E's requested capital expenditure funding for MWC 27 is justified.

3.6. Leak Survey and Repair

Gas pipelines carry flammable gas under pressure. Pipeline safety regulations require periodic surveys on PG&E's distribution system to find gas leaks. PG&E is required to repair every potentially hazardous leak it finds to reduce the risk of damage or injury due to gas leaks from distribution pipeline. SB 705 requires that PG&E "[p]rovide for effective patrol and inspection of the commission-regulated gas pipeline facility to detect leaks" consistent with industry best practices.

PG&E forecasts $33.84 million for gas distribution leak survey expense (MWC DE) and $102.14 million for corrective maintenance (MWC FI), of which

$93.44 million is for repairing leaks not caused by dig-ins. The 2014 forecasts are $14 million and $65 million, respectively, over 2011 recorded levels.[19]

DRA recommends reducing PG&E's leak survey forecast (MWC DE) by $16.3 million. The forecast difference between PG&E, DRA and TURN for MWC DE consists of the following:

	($ in Millions)		
Element	PG&E	DRA	TURN
Routine Leak Survey	$20.04	$ 7.56	
Downgrade – No Repair	$ 1.75	$ 0.40	
Re-Checks	$ 6.37	$ 5.09	
Other	$ 5.64	$ 4.45	
Total	$33.80	$17.50	$25.14

PG&E plans to implement various leak survey technique enhancements to improve system safety. PG&E traditionally surveys its distribution system utilizing sensing equipment to locate and grade gas pipe leaks. For 2014, PG&E seeks increased funding to pay for accelerating from a five-year to a three-year cycle for routine leak surveys. PG&E also plans to focus additional resources in areas with known high leak rates, where clusters of leaks have been repaired. PG&E plans to perform annual leak surveys of 1,000 clusters in 2014, for a total of 57,000 services annually, representing 1.7% of its distribution system. The

[19] PG&E forecast the incremental cost of performing leak surveys with the Picarro Surveyor (lower leak survey costs and higher leak repair costs) in MWCs DE and FI and, to avoid double-counting, subtracted the leak survey and repair forecast in MWC JS from the amounts forecast in MWCS DE and FI.

pipe will be surveyed by identifying segments with the most clusters of historical leaks.

PG&E traditionally performs its routine leak surveys by foot, but is also phasing in use of the Picarro Surveyor technology to eventually survey its entire system. The Picarro Surveyor utilizes new technology designed to be 1,000 times more sensitive than current equipment based on foot surveys, providing almost a three-fold increase in leak detection effectiveness and efficiency. Picarro will be used for surveying the highest risk pipe starting with three divisions in 2014, up to six divisions in 2015 and 10 divisions in 2016. The three divisions that PG&E plans to survey using the Picarro Surveyor in 2014 will total approximately 565,908 services. This plan should allow PG&E to better evaluate pipe with greatest likelihood of leaking. PG&E anticipates finding significantly more leaks with Picarro compared with traditional methods.

PG&E also forecasts $6.375 million for Grade 3 leak rechecks every 15 months. The American National Standards Institute (ANSI) Gas Piping and Technology Committee's (GPTC) latest guidance is to recheck Grade 3 leaks at least once every 15 months.

PG&E attributes the test year expense increase primarily to: (1) moving from a five-year to a three-year leak survey cycle, (2) more than twice as much time will have passed since the prior leak survey compared to the 2011 test year, resulting in locating more leaks to be repaired, and (3) use of the Picarro Surveyor, which is expected to find more leaks than traditional methods.

DRA recommends a $16.3 million reduction to PG&E's MWC DE forecast based on (1) a five-year leak survey cycle, (2) using Picarro Surveyor to survey fewer leak clusters, (3) applying a lower leak find rate, (4) using 2011 recorded costs for Downgrade No Repairs, (5) assuming Grade 3 leaks are rechecked only

within a 15-month cycle, and (6) assuming fewer employees for Picarro project support. DRA argues against repairing above-ground Grade 3 leaks.

DRA estimates a different number of Picarro Surveyor units compared to traditional foot survey units (Surveyor units are less costly). DRA applies a 1.33 multiplier, rather than PG&E's 2.71 multiplier, as a leak find rate using the Picarro Surveyor. DRA derives a leak find rate for the Picarro Surveyor for 2014 based on the 2011 historical leak find rate multiplied by an increase of 33%. DRA's leak survey recommendation is based on PG&E performing 50% of the survey using traditional foot survey and mobile methods and 50% using the Picarro Surveyor.

TURN recommends reducing PG&E's leak survey forecast by $8.66 million, and reducing PG&E's leak repair forecast to $27.8 million based on (a) a five-year leak survey cycle and (b) a lower leak find rate for the traditional foot survey than PG&E forecasts. TURN agrees that a two-way balancing account for leak repair costs is reasonable. TURN does not dispute that the ANSI GPTC guidelines establish the industry best practice, and does not oppose PG&E's proposal to accelerate Grade 3 rechecks as long as PG&E maintains a five-year survey cycle. Because Grade 3 leaks are non-hazardous and are expected to remain so, TURN argues that more frequent rechecks won't improve safety.

The CCUE supports PG&E's use of a three-year survey cycle, but argues that PG&E should conduct traditional foot surveys concurrently with use of the Picarro Surveyer, which would increase leak survey and repair costs. CUE argues that traditional foot surveys and Picarro each find different leaks and that the two methods are not substitutes for each other. CUE calculates that

implementing Picarro along with the traditional methodology, not instead of it, would cost an additional $3 million.

Picarro disputes CUE's claim that traditional surveys find different leaks than does the Picarro Surveyor. Picarro denies any correlation has been shown between the type of leaks located using the traditional method versus using the Picarro Surveyor. Picarro claims that each technology finds the same type of leaks, but the Picarro Surveyor technology finds far more total leaks faster and with greater accuracy. Picarro thus proposes that the Commission approve use of the Picarro Surveyor in place of traditional survey methods for leak survey and repair work. Parties' disagree over the MWC DE forecast largely due to different views concerning how frequently PG&E should conduct leak surveys of its gas distribution system, and what combination of survey techniques and methodologies should be used to detect leaks. Distribution facilities in principal business areas are surveyed annually. Copper services are surveyed every three years. For the remaining 94% of its gas distribution system, PG&E currently performs routine leak surveys on a five-year cycle.

By shifting to a three-year cycle, PG&E forecasts surveying 1.3 million services and associated main in 2014.

Picarro also supports a three-year survey cycle, arguing that existing federal regulations mandating a five-year survey cycle are outdated and based on legacy technology with significant performance limitations. Picarro claims that the consequences of waiting to survey portions of PG&E gas pipelines every five years are potentially catastrophic.

CUE also supports a three-year cycle, arguing that retaining a five-year cycle would only save $8 million of spending on leak inspection costs, and would

be "penny wise and pound foolish" in terms of the increased safety risk involved in finding and repairing more leaks sooner.

PG&E argues that the frequency of leak survey cycles should be based on industry best practice. Because SB 705 provides no definition of industry best practices, PG&E proposes its own standard. If 25% or more of industry operators are doing a particular safety practice, PG&E defines that as a best practice. In the case of leak surveys, PG&E defines surveying the entire system at least once every three years as a best practice. PG&E presented a benchmarking study that shows 25% or more of the operators in the study conduct leak surveys at least once every three years.

TURN disputes PG&E's claim that a three-year leak survey cycle necessarily constitutes industry best practice. TURN argues that the relevant benchmark should be overall number of leaks found based on the overall mix of survey strategies used, which reflects risk reduction. Although PG&E identifies a three-year survey cycle used by other operators as an industry best practice, those other operators have not implemented Picarro, and probably have not implemented other measures such as cluster surveying.

PG&E is implementing various measures that will result in finding more leaks, including the Picarro Surveyor, cluster surveying, and more frequent leak rechecks. For each mile surveyed using Picarro, PG&E expects to find 2.71 times as many leaks as compared to conventional methods. TURN claims that, given the higher number of leaks found per mile using Picarro and using annual cluster surveys, PG&E will find as many leaks per mile overall if it keeps surveying on a five-year cycle as it would if it accelerated its standard surveying to a three-year cycle and did not implement the other measures.

PG&E failed to conduct a cost-effectiveness analysis resulting from going to a three-year survey cycle, aside from noting that shortening the cycle will find more leaks. If the goal was just to find more leaks at any cost, PG&E could simply quadruple (instead of double) its survey budget.

Given the multiple leak survey techniques that PG&E proposes to implement, the uncertain impact of changing the leak survey frequency, the new technologies and better trained staff being deployed and the other planned initiatives, TURN recommends staying with a five-year survey for now. TURN argues that shifting to a three-year survey interval should wait at least until the effects of PG&E's other leak survey techniques are assessed. For the 2017 GRC, there should be more data to evaluate impacts and benefits of a shorter leak survey cycle. TURN claims current data on leak find rates are not consistent enough to demonstrate a convincing trend or to justify moving to a three-year interval. TURN notes that leak find rates during the five-year cycles from 2005 through 2008 were far lower than those afterward.

TURN argues that PG&E should first implement Picarro in all divisions on a five-year cycle, and then assess if the safety benefit warrants moving to a three-year cycle. TURN suggests that continuing to use Picarro on a five-year cycle while expanding the leak cluster survey program may be a more cost effective way of finding more leaks than surveying the entire system more frequently.

PG&E disagrees with postponing changes in leak survey cycle until impacts of the leak cluster/repair efforts and Picarro leak surveys are known. PG&E argues that changing the leak survey frequency from five years to three years is a critical element in achieving its goal to improve system safety.

Discussion

We adopt a 2014 funding for MWC DE sufficient to enable PG&E to meet a superior standard of safety, recognizing that gas leaks pose the most significant source of system safety risk. We generally support PG&E's planned use of leak survey enhancements, as discussed below.

We support PG&E's plans for enhanced survey practices, including doing traditional foot surveys in parallel with use of the Picarro Surveyor. We decline to adopt Picarro's proposal that the Picarro Surveyor be exclusively used in place of traditional foot surveys for leak survey and repair work. Until PG&E gains greater experience and performance results from the Picarro Surveyer, we find insufficient basis to conclude that the traditional foot survey can be completely substituted with Picarro without reducing overall effectiveness of PG&E's ability to find and repair leaks.

The most significant dispute over PG&E's leak survey forecast relates to how frequently PG&E should conduct leak surveys of distribution pipe. Increasing leak survey cycle frequency is only one of several strategies PG&E can use to detect and repair leaks more effectively. In this regard, Cycla states that "identifying and evaluating various strategies from a cost and risk reduction perspective would be an essential step in changing strategies" to reduce the number hazardous pipeline leaks.[20] As noted by Cycla, however, PG&E has not attempted to evaluate the best rate of phase-in of the various measures proposed to reduce the number of hazardous leaks (e.g., more cluster surveys, pipe replacement, and more rapid response to reported leaks).

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[20] *Id*. at 48.

Regarding the controversy over whether PG&E should conduct routine leak surveys on a specific cycle frequency, we consider the choice of a specific leak cycle frequency is ultimately a management decision that is PG&E's responsibility. We adopt a funding level sufficient to enable PG&E to achieve an overall performance results in leak cycle detection and repair consistent with best industry practice. We take a two-pronged approach to setting the appropriate funding level. First, we set an initial provision in the adopted 2014 revenue requirement. Second, we make provision for PG&E to recover additional costs relating actual leaks identified and repaired through a two-way balancing account up to a prescribed maximum rate cap, as discussed below.

As a theoretical principle, the longer the interval between surveys, the more leaks may develop and go unrepaired, thus increasing the number of leaks and related safety risk. Based on this principle, more leaks would be detected after a five-year survey than a three-year survey. Theoretically, PG&E could find even more leaks by conducting leak surveys more frequently than at three-year intervals. Yet, PG&E has not proposed, for example, a two-year or one-year survey cycle. At some point, the incremental cost burdens of more frequency leak surveys become prohibitively expensive. Thus, in determining a reasonable survey cycle frequency, the safety benefits, as well as related cost burdens imposed on ratepayers must both be weighed.

PG&E has not quantified through an independent safety risk assessment of the optimal leak survey frequency in terms of the relative trade-offs of risks and costs. Instead, PG&E's primary basis for proposing a three-year cycle is its claim that the best industry operators use a three-year survey cycle. PG&E seeks to use comparisons with other utility practices as a means of establishing its own industry best practice. In this regard, such comparisons must account for

differences among utilities that may call into question the validity of the comparison.

We agree that ratepayer funding should be sufficient to enable PG&E to detect leaks on a level comparable to the best industry operators. Because PG&E has not attempted to evaluate or quantify the best rate of phase-in of the various measures proposed to reduce hazardous leaks, as noted by Cycla and TURN, it is difficult to establish specific objective safety performance metrics that should be funded. Similarly, the precise cost of an optimal phase to achieve such metrics is likewise uncertain. Faced with these limitations in the record, we adopt a funding approach that it lies within the range forecasted by PG&E at the high end and by TURN at the low end. Both PG&E's and TURN's estimates of the leak find rate with Picarro Surveyor rest on PG&E's pilot test of the Picarro system. PG&E used the ratio of leaks found with traditional methods, to the results of a resurvey with Picarro.

For purposes of setting the 2014 test year revenue requirement, we set the leak survey and repair expense levels based on the assumptions relied upon by TURN which was predicated on continuation of a five-year routine leak survey cycle. TURN forecasts a leak rate of 2.457% for traditional (non-Picarro) leak surveying, based on the average leak rate for 2011 - 2012. TURN's estimated leak find rate of 2.547% affects both the forecast number of leaks found through the traditional leak surveys as well as the forecast number of leaks found with the emerging Picarro Surveyor leak survey technology.

By setting the 2014 revenue requirement using TURN's figures, we take a conservative approach, thereby protecting ratepayers against the risk of overfunding relative to actual expenses. At the same time, we provide a prospective vehicle for PG&E to recover its reasonable expenses that exceed this

minimum level funded in the 2014 revenue requirement through the balancing account mechanism discussed in the next section.

We also set a maximum rate cap for the leak survey and repair balancing account, however, at a level not to exceed PG&E's forecast annual amount for leak survey and repair. PG&E used its baseline leak find rate of 3.561% to develop an estimated Picarro leak find rate of 9.65%. Although PG&E's forecast assumes a three-year routine leak survey cycle, the actual amount that PG&E may ultimately recover through balancing account adjustments will depend on how PG&E chooses to integrate leak survey frequencies into its other enhanced leak detection and repair strategies.

For purposes of setting the caps on cost recovery through the balancing account, we utilize the amounts that PG&E has forecasted for the following major work categories (MWC): DE- Natural Gas Leak Survey; FI- Leak Repair; Maintenance Activity Types (MAT) HY 7- Meter Set Leak Repair FHK- Atmospheric Corrosion Inspection Costs. Separate capped amounts shall apply individually to each MWC. Based on PG&E's forecasts, the maximum capped amounts for each MWC are as follows:

	$ in Millions
DE Natural Gas Leak Survey	$ 33,840
FI Leak Repair	102.141
HY7 - Meter Set Leak Repair	7.756
FHK Atmospheric Corrosion Inspection	4.737
Total	$148.474

PG&E claims a three-year survey cycle is required to meet industry best practice, but that claim is based on one aspect of operators' leak survey programs. As noted above comparisons of isolated metrics among differing

utilities may not be particularly informative. In this instance, other operators using a three-year cycle have not implemented use of Picarro, and probably have not implemented other measures such as cluster surveying. We conclude that the more relevant benchmark of industry best practice for leak surveys is performance based on optimization of all of techniques and strategies used to detect and repair leaks. In the area of leak survey and leak repair, TURN witness Sugar showed that PG&E's use of Picarro, cluster surveying and accelerated rechecks was estimated to result in the same performance outcome (measured by number of leaks found) as from a three-year cycle, but without other enhanced techniques.

By combining cluster surveying, which targets the portion of the system with the most leaks, with the use of Picarro, which finds leaks at more than twice the normal rate, plus accelerated rechecks, the resulting leak find rate is similar to using a three-year routine survey cycle with no other improvements.[21]

Based on the ratemaking approach we are adopting, as outlined above, PG&E thus should be able to achieve leak find rates consistent with best industry practice by implementing Picarro and cluster surveys as proposed while incorporating prudent adjustments in the frequency of routine leak survey cycles. We recognize that Picarro Surveyer will only be used in limited regions initially, and thus, any enhanced performance benefits will not be spread uniformly throughout PG&E's service territory.

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[21] Ex. 180 (PG&E Response to TURN-104-02); and TURN Opening Brief, p. 51.

In terms of overall performance in finding leaks, however, based on the balancing account provisions we adopt, PG&E should thus have the flexibility to be able to match other industry leaders, consistent with industry best practice.

PG&E shall remain responsible for integrating and optimizing the phase in of the each of the enhanced leak survey techniques outlined in its test year proposal to achieve the results consistent with best industry practices, and implemented in the most cost-effective manner. Any balancing account costs that PG&E seeks to recover in excess of the adopted 2014 revenue requirement are to be based upon cost-effective and optimizing practices for achieving the best results for the money spent.

While we adopt balancing account treatment at this time in view of the uncertainties involved in PG&E's implementation of an optimizing gas leak detection and repair strategy, we believe that PG&E needs to do more work in developing objective performance metrics relating to gas leak detection and repair as well as other safety performance metrics. We are also concerned about the effects of gas leakage on greenhouse gas (GHG) emission levels, and the resulting mitigation measures that should be integrated into an overall leak detection and repair strategy.

In this regard, we take note of Senate Bill 1371, which is currently pending before the state legislature. On page 7 of the bill, the first full subsection (6), the commission is to adopt rules to, to the extent feasible, "require the owner of each commission-regulated gas pipeline facility . . . to calculate and report to the commission a baseline systemwide leak rate, along with any data and computer models used in making that calculation . . ."

In line with the intent of SB 1371, we expect PG&E to begin working on developing the data for a base line system wide leak find rate that could form the

basis setting performance metrics and rate levels consistent with best practice. We expect to explore this issue and provide more specific direction to PG&E in the next phase of this proceeding dealing with prospective recommendations in the Safety Consultant Reports relating to PG&E's risk assessment and mitigation practices.

We adopt PG&E's forecast of $6.375 million for leak re-checks as reasonable and based on an industry best practice as required by SB 705. PG&E has already shifted to a 15-month recheck cycle and forecasts continuing to do so.

3.6.1. Leak Survey and Repair Balancing Account

PG&E proposes that a two-way balancing account be established to cover leak survey (MWC DE) and repair (MWC FI) costs, meter set leak repair costs (MAT HY7) and AC costs (MAT FHK). Authorizing a balancing account for these costs will provide an additional source of funding to find and fix leaks, while protecting customers from over-paying in the event that the actual leak find rate is less than forecast.

DRA opposes adoption of a two way balancing account for the costs of leak surveys and leak repairs, arguing that these work activities are not new. DRA claims the system leak rate has been decreasing and there is historical leak survey and repair data. DRA argues that the two-way balancing account provides no incentive for PG&E to control costs.

PG&E's proposal accounts for $147.1 million, or 32%, of its total 2014 forecast. DRA claims that PG&E's proposal is unreasonable and should be rejected.

Discussion

We adopt PG&E's proposal to implement a two-way balancing account for recovery of the difference between forecasted and actual costs for leak survey (MWC DE) and repair (MWC FI), meter set leak repair (MAT HY7) and AC (MAT FHK). Balancing Account authorization is warranted in view of the uncertainty as to how many leaks PG&E will find and need to fix during the 2014-16 cycle, particularly due to the range of new enhanced leak survey techniques to be used. The balancing account will provide a vehicle for recovery of funds to perform this work to the extent that the actual scope of leaks surveyed, found and/or repaired differs from the levels reflected in the 2014 adopted revenue requirements. Costs recoverable through the balancing account will be based on actual units of work, but limited to the adopted per-unit labor and overhead rates for the applicable work activity and capped at PG&E's forecast amounts, as discussed in the preceding section.

3.6.1.1. Corrective Pipeline Maintenance (MWC FI)

PG&E forecasts $102.1 million in expense in MWC FI for repairing leaks found through surveys, preventive maintenance and customer calls. Other corrective maintenance activities under MWC FI are CP restoration, regulatory station repair, distribution valve repair and gas overbuilt corrective maintenance. PG&E's projected 174% increase in leak repair and corrective maintenance expense is based on the use of the Picarro surveyor, the shift to a three-year survey cycle, and calculation of a higher leak find rate for traditional surveying, with rapid repair of Grade 2 and Grade 2+ leaks. The higher traditional survey leak find rate contributes about $15.6 million to the increase, the shift to a three-

year survey contributes about $15.8 million, and the use of Picarro contributes almost $30 million.

PG&E forecast for MWC FI is based on a leak find rate of 34.3 leaks per thousand services using traditional foot survey methods, 2.71 times as many leaks (i.e., 92.8 per thousand services surveyed) using the Picarro Surveyor, and 216.4 leaks per thousand surveyed when the survey used to survey leak clusters with the highest number of historical leaks (based on 80 leaks per thousand services surveyed using foot survey, multiplied by 2.71 because PG&E plans to use the Picarro Surveyor. The higher traditional survey leak find rate contributes about $15.6 million, shifting to a three-year survey contributes about $15.8 million, and using Picarro contributes almost $30 million. PG&E is also accelerating repairs to Grade 2 leaks[22] from within 18 months to within 15 months.

The PG&E forecasted leak find rate of 3.43% for traditional surveying is based on the weighted average find rate for 2008-2012. PG&E analyzed the relationship between leak find rates and the average time since the prior survey using data from 2011 and 2012. PG&E then applied the resulting relationships to forecast leak find rates for 2013 and 2014. PG&E performed an accelerated leak survey from 2008-2010 of its entire gas system on a three-year interval. When PG&E performed its 2011 leak survey, the average time since the prior survey

[22] Gas Pipeline leaks are graded by repair priority based upon the degree of hazard identified. Grade 1 leaks are deemed hazardous and dangerous and must be repaired immediately. Grade 2 and 2+ leaks are classified as not currently hazardous, but could become so and usually must be repaired within a specified time frame. Grade 3 leaks are classified as being not hazardous nor believed to ever become so, and do not require repair, but must be rechecked on a longer schedule.

was thus less than two years. When PG&E performs its 2014 survey, the average time since the prior survey will have been more than four years. Thus, the gas distribution system will have had more than twice as much time to develop gas leaks. Even accounting for increased customer-reported leaks, PG&E argues that this would almost double the 2011 leak find rate. PG&E's forecast is 1.4 times the 2011 find rate.

Higher costs associated with finding more leaks would be incurred in the first survey cycle, but the leak find rate should normalize after that. There would be fewer open leaks with a three-year cycle than with a five-year cycle. Costs of transitioning to a three-year cycle would be incurred once over a three-year period. After that, the benefits of having fewer open leaks are ongoing. Also, by conducting leak surveys more frequently, PG&E would find some Grade 2 or Grade 3 leaks that, had PG&E waited longer, would have become Grade 1 leaks. Finding those leaks more quickly will improve public safety and generate cost efficiencies because repair of Grade 2 and 3 leaks can be scheduled and performed more cost effectively.

CCUE supports PG&E's proposal for a three-year leak survey using the Picarro surveyor in conjunction with the traditional methodology. CCUE suggest that the combined find rate for Picarro plus traditional surveys could be as high as 10.72%.

DRA forecasts a lower corrective maintenance expense by $66.5 million compared to PG&E's forecast, assuming fewer leaks, a five-year leak survey cycle, a lower leak find rate, no repairs for above-ground Grade 3 leaks, and surveying fewer services. DRA forecasts the number of leaks PG&E will find in 2014 using the 2011 leak find rate. DRA forecasts a leak find rate of 24.4 leaks per thousand services surveyed using traditional methods, and a leak cluster survey

find rate of 32.5 leaks per thousand services surveyed using Piccaro. For Main Leak Repair, DRA recommends the same changes as for Above-Ground and Below-Ground Leak Repairs, and opposes repairing above-ground Grade 3 leaks. DRA recommends use of 2011 recorded costs for Main Dig-In Repairs and $0 for Service Dig-In Repairs. For Gas Overbuild, DRA states that PG&E has not adequately supported its forecast.

TURN recommends reductions in the MWC FI forecast of $27.8 million (composed of $14.1 million (based on a lower leak find rate) and 13.7 million (based on a five-year survey cycle). TURN agrees with the multiplier for Picarro survey and Picarro leak cluster surveys, but applies a leak find rate of 2.457% using traditional methods based on the average leak rate for 2011-2012.[23] TURN disputes PG&E's leak find rate for the continuing standard foot survey. PG&E forecasts a leak find rate of 3.43% for traditional foot surveying based on the weighted average find rate for 2008-2012. This forecast is significantly higher than the 2011 leak find rate of 2.44%. TURN claims that PG&E's weighted average figure is inappropriate, because 2008-2010 data reflect higher find rates caused by accelerated surveying conducted in 2009 and 2010. TURN claims that the 2011-2012 average leak find rate of 2.54% is more reasonable for forecasting by excluding both low data from 2005-07 and high data from 2009-2010.

PG&E disputes DRA's and TURN's forecasted 2014 leak find rates. DRA uses the leak find rate that PG&E experienced in 2011 after only 1.92 years had passed since the prior survey. By contrast, 4.33 years since the prior survey that will have passed in 2014.

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[23] *See* TURN Testimony of John Sugar, referencing TURN DR 52-11, Attachment 1.

PG&E's forecasted leaks repairs for 2014 is based on a combination of found leaks expected in 2014 and in 2013. DRA assumed that a certain percentage of leaks found in 2014 would require repair, but did not account for the rate of Grade 2 leaks found the prior year. PG&E argues that DRA's methodology yields a leak repair rate of 72.1%, not the 48.5% that DRA assumed. DRA compared the number of leaks found to the number of leaks repaired during 2011. This approach does not account for the rate of Grade 2 leaks found the prior year but is based on a single year, which is not indicative of the repair rate for any other year. DRA's methodology of comparing the number of leaks found each year to the number of leaks repaired each year yields a four-year average of 78.1%.

TURN agrees that leak find rates will be higher if the survey cycle is longer, but argues that the impact of increasing the survey cycle is not linear, and that PG&E fails to properly quantify the data.

Discussion

We adopt TURN's forecast reducing PG&E's MWC FI forecast by $27.8 million composed of $14.1 million (based on a lower leak find rate) and 13.7 million (based on a five-year survey cycle). We base the adopted forecast on TURN's combined (traditional and Picarro survey) leak find rate of 2.547% instead of PG&E's find rate of 3.56% of services. The adopted forecast assumes a five-year routine leak survey cycle, but incorporates PG&E's estimate for cluster surveys, estimated as 2.3 times the system average leak find rate. PG&E's estimate includes additional leaks that will need to be repaired due to the use of Picarro. We decline to use PG&E's forecast leak find rate for traditional surveying uses data for setting 2014 revenue requirements. As noted in the

preceding discussion, however, PG&E has the management discretion to adjust its leak survey cycle within the limits we have prescribed.

The PG&E forecasted leak find rate of 3.43% for traditional surveying is based on the weighted average find rate for 2008-2012. By contrast, the 2011 leak find rate was only 2.44%. The 2008-2010 data reflect the significantly higher find rates caused by accelerated surveying conducted in 2009 and 2010.

The low find rates of 2005-2007 are likely not representative of the 2014-2016 cycle due to the widespread lack of compliance with proper leak survey procedures in 2004-2007. PG&E implemented an "accelerated leak survey" in 2008-2010 as part of a remedial monitoring program. PG&E performed extensive re-surveying in 2009 and 2010. Just as the 2005-2007 data are artificially low, and the 2009 and 2010 data are too high, since they reflect the accelerated leak surveys.

Due to the factors impacting leak find rates in 2007-2010, we conclude that the average 2011-2012 leak find rate of 2.54% is the most reasonable for forecasting purposes. This number excludes both extremes of low data from 2005-2007 and high data from 2009-2010.

PG&E's leak find rate analysis relies on the assumption that the relationship between the leak find rates in 2011 (2.44%) and 2012 (2.91%) is due entirely to elapsed time between the last survey, and will remain constant in the future. TURN requested more detail from PG&E as to the leak rates of pipe segments based on time elapsed since the last survey. PG&E did not have that information. As noted by TURN, leak find rates for pipe result from a number of factors, including pipe material surveyed and terrain in which the pipe was laid. Because these other factors are not constant each year, we cannot infer that the

different types of pipe will be surveyed or repaired during the 2014-2016 cycle will be the same as for the historic period.

The cost of leak repairs depends on how many and what grades of leaks are discovered during a leak survey, and how many get reported. Leak repair costs have several components. Leak find rates result from various factors, including, the pipe material surveyed, and terrain in which the pipe was laid. These other factors are not constant each year. While some leak repair is completed on above-ground facilities, many leaks require excavation below ground. The largest changes between 2011 and 2014 are in main leaks and below ground service leaks which increase by 230% and over 4,000% respectively.

To the extent that PG&E's actual leak find rate exceeds the level funded in rates, PG&E can seek subsequent recovery of the additional repair costs included in the balancing account, subject to the limits we have prescribed, as discussed in Section 3.6.1.

3.7. Gas Field Services and Response (MWC DD)

PG&E's Gas Field Services and Response function is responsible for addressing customer service requests, including service connects, pilot relights, and reports of gas odors and for maintenance including AC remediation and regulator replacements. SB 705 mandates that PG&E have a plan, consistent with industry best practices, to "[p]rovide timely response to customer and employee reports of leaks and other hazardous conditions and emergency events."

PG&E's Field Services and Response expense forecast includes $105.956 million for field services (MWC DD) and $7.756 million for AC work and meter set leak repair (MWC HY), an increase of $37 million over 2011 levels. The increase is primarily due to increased staffing to respond to all customer

reported gas odors within 30 minutes 75% of the time and within 60 minutes 99% of the time.

DRA and TURN recommend reducing PG&E's MWC DD forecast by $9.524 million and $6.518 million, respectively. DRA also recommends reducing PG&E's MWC HY forecast for leak repair and AC by $2.093 million.

3.7.1. Pilot Relights (MAT DDD)

PG&E forecasts $31.5 million in expenses for pilot relights on customers' gas appliances for 2014 based on 2011 base year recorded amounts. TURN claims that a more appropriate forecast is $25.0 million using the 2007-2012 cost trend, though a more accurate forecast based on the 2004-2012 trend would result in an even lower forecast. TURN claims the declining 2007-2012 trends is not an anomaly but reflects state policies banning the sale of new appliances with pilot lights. Modern appliances are required to have electronic ignitors, thus reducing pilot relights as appliance stock turns over.

TURN estimates that customer installation of these new appliances will reduce PG&E's pilot relight expenses by $6.5 million in 2014. PG&E disputes TURN's premise, claiming that the lower number of pilot light requests in 2012 was due to a late winter, not new appliances. PG&E argues that this lower number cannot, therefore, be used to project continued decreases through 2014. Any impact of mild weather at the end of 2012 can be captured by using a 2004-2012 time series, or by eliminating 2012 and using a 2004-2011 time series.

Also, even with the lower number of pilot relights, PG&E required $96 million in 2012 to perform all of the MWC DD work. Counting the full-year carrying cost of new hires and applying standard wage escalation brings this figure to $104.657 million, which is $5 million higher than TURN's 2014

recommendation. PG&E also claims it needs additional resources to treat an additional 85,000 calls as Immediate Response.

Discussion

We conclude that TURN's proposed reduction in PG&E's forecast of $6.5 million for pilot relight expenses is reasonable and approve it. We disagree with PG&E's claim that the mild winter in 2012 is sufficient basis to dismiss TURN's calculation of the lower number of pilot relights. TURN's calculation is not based just on 2012 data, but on the historical cost trend over several years. PG&E's explanation of one mild winter in 2012 does not account for the multi-year declining trend in pilot relight data, coupled with the fact that new appliances are required to have electronic ignitors, thus reducing pilot relights as appliance stock turns over.

3.7.2. Gas Service Representative (GSR) Scheduling/Dispatching

PG&E forecasts $105.96 million in 2014 in MWC DD for the addition of 120 GSRs, six supervisors and six clerks to meet new safety goals to investigate customer reports of gas odors consistent with gas industry best practices. PG&E forecast 40 GSRs added in 2012 and 80 more GSRs in 2014.

PG&E has historically responded to customers' gas odor calls as either within 60 minutes (for urgent matters) or at least within the same day. PG&E's goal is to improve its response time to customer reports of gas odor to achieve top-quartile performance within the industry. PG&E developed a two-phased approach for improvement. In the first phase, PG&E hired 40 GSRs during 2012 to enable responses to all calls classified as "Immediate Response" within 30 minutes 75% of the time and within 60 minutes 99% of the time. In the second phase, PG&E plans to hire 80 more GSRs during 2014 to enable ***all*** gas odor calls

to be treated as "Immediate Response" calls. This new standard is expected to double the number of calls by 85,000 to be treated as immediate response.

As noted by Cycla, improving emergency response to leaks reported by the public addresses a major contributor to safety risk.

DRA forecasts $96.4 million in 2014 for MWC DD, which is limited to 2012 recorded amounts. DRA claims that PG&E has already hired most of the 80 GSRs planned for 2014 and has achieved the targeted response times to all gas odor calls. PG&E explains that it has already met its 2012 goals, and acknowledges that 2012 and 2014 response time goals are the same. Starting in 2015, however, new higher goals are to take effect. PG&E seeks additional staff during 2014 to meet the new 2015 goal.

PG&E also disputes DRA's claim that the 80 GSRs forecasted for 2014 have already been hired. Out of 77 GSRs hired in 2012, 37 of them were backfills of existing positions. PG&E hired 40 new positions in 2012. Thus, PG&E still forecasts a need to hire 80 more GSRs in 2014 to reach its target level of 120 GSRs.

Discussion

We are supportive of PG&E's goal to shorten response times to odor complaints by treating all such complaints as "immediate response" calls. The increased emergency responsiveness goals which PG&E has set reduce the risk of an incident and consistent with industry best practices, as confirmed by Cycla.

For the 2014 test year, we approve funding for the annualized cost of the 40 GSR positions hired in 2012, escalated to 2014 dollars. We acknowledge that 2012 recorded spending does not reflect a full year's cost of GSRs hired to help meet PG&E's 2012 response goals, nor does it reflect wage escalation to 2014. The additional 40 GSRs should be sufficient for PG&E to satisfy its 2012-2014 response time goals.

We decline, however, to approve funding at this time for the additional 80 GSRs requested. Accordingly we reduce PG&E's forecast to exclude these 80 GSR positions. Although PG&E claims its needs to hire the additional 80 GSRs during 2014 to meet the faster response time goals planned to take effect in 2015, we question, however, whether PG&E has adequately reflected appropriate efficiencies in adding such a large staffing increase. In this regard, Cycla believes that inefficiencies associated with adding field service response personnel during 2011 may have occurred, given the cost escalations between 2010 and 2011. Cycla concludes that the impacts of increasing GSR staff to the levels forecast by PG&E "has not been demonstrated." Cycla notes that in New York, for example, utility operators minimized the need for additional GSR personnel to meet performance targets by cost effective methods such as cross training and split shifts.[24] Cycla acknowledges, however, that while PG&E's increased staffing costs are high, the safety risk reduction should be significant.[25]

PG&E used 2011 data to calculate additional GSR positions deemed necessary to reduce the response time per call to 30 minutes 75% of the time and 60 minutes 99% of the time based on 2015 goals. PG&E presented its calculations in Table 7-6, on page 7-17 of Exh. 14 (PG&E -3) Gas Distribution Testimony. PG&E acknowledges that the additional GSRs would not be 100% utilized just in responding to emergencies and gas odor calls. PG&E states that when the new GSRs are not responding to emergencies and gas odor calls, they would support other compliance work, including: (1) more timely response to

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[24] Exhibit 167, Cycla Report, Attachment 6 at 22.

[25] *Id*. at 49.

customer requests; (2) reduced overtime for current employees; and (3) completing mandated work identified through leak and AC surveys. In assessing the claimed need for additional GSRs, however, PG&E does not quantify the efficiency savings offsetting forecast costs to reflect the additional value of other services provided by the additional GSRs.

Before approving funding for the remaining 80 GSRs, we conclude that a more robust showing of cost efficiencies is warranted based on the concerns identified by Cycla, as noted above. We can then assess whether or by how much a further increase in GSRs is needed to meet the higher customer response standard, based on optimum use of staff.

Since PG&E's new higher customer response performance standard wouldn't take effect until at least 2015, customers would realize no benefit during 2014 from the 80 new GSRs, even based on PG&E's assumptions. Any ratepayer benefits from shortened response times would only be realized after 2014, even under PG&E's assumptions. Thus, deferring ratepayer funding for 80 new GSR positions to the next GRC cycle will not improve response rate times that PG&E estimates for 2014. While PG&E's goal of further enhancing customer response rates is commendable, it is premature to approve funding for 80 additional GSRs for this GRC cycle. Considering such factors as those noted by Cycla, we expect a showing in the next GRC on how PG&E proposes to optimize any further increases in GSRs to further shorten response times to odor complaints by treating them all as "immediate response" calls.

3.7.3. Leak Repairs and AC (MWC HY)

PG&E forecasts $7.8 million for expenses related to AC remediation and leak survey repairs at meters. PG&E's forecast of meter set leaks and AC is based on recorded data. DRA recommends a reduction of $2.09 million based on

the ratio of recorded-to-proposed costs for 2012, and because all backlog work will be completed before 2014. Since PG&E spent 40% less in 2012 compared to its 2012 forecast, DRA recommends a corresponding 40% reduction in the 2014 forecast.

PG&E disputes DRA's claimed reduction, arguing that the 2012 forecast variance relates to catching up on repair of a historical backlog of leaks, but has no bearing on the 2014 forecast which is based on new leaks to be identified and repaired. PG&E's 2014 forecast includes $6.3 million that is based on historical leak find rates, as opposed to leak repair rates, adjusted for a three-year leak survey cycle. The remaining $1.4 million is allocated to atmospheric corrosion work. We adopt a 2014 forecast based on historical leak find rates as calculated by PG&E, but adjusted to reflect a five-year routine leak survey cycle, and adjusted for TURN's leak find rate, consistent with our findings above. The adjusted forecast is $5.771 million related to atmospheric corrosion remediation and leak survey repairs.

3.7.4. Regulator Replacements (MWC 74)

PG&E forecasts $14.878 million (per comparison exhibit) for regulator replacements capitalized in plant in service for 2014. The majority of PG&E's commercial size regulators have non-internal relief valves (non-IRVs). PG&E requests $14.440 million in capital for 2014 to replace 20,000 commercial-sized regulators that have no internal relief valve. Many non-IRV regulators are over 20 years old, and could experience problems due to valve hardening, which could affect the valve's ability to limit pressure build-up under low-flow or no-flow conditions. PG&E plans to replace the non-IRV regulators with IRV regulators to mitigate this risk, and to ensure safer delivery of distribution pressure to customer gas lines and equipment.

DRA recommends a reduction of $10.95 million based on a lower unit cost using 2012 recorded data, and commercial unit cost estimated as twice the cost of residential. PG&E's estimate is based on blended 2011 unit costs for residential and commercial. DRA claims that PG&E failed to replace any of the 2,924 commercial regulators forecasted for 2012.

TURN recommends funding 25% of PG&E's forecast amount to support opportunistic replacements of non-IRV regulators. TURN claims that PG&E has not provided sufficient evidence to show that accelerated replacement at is necessary for safety or reliability.

TURN argues that PG&E's opportunistic replacement appears to be working satisfactorily, though the lack of data on incidents and replacements makes it impossible to reach a solid conclusion. TURN thus recommends authorizing 25% of the requested funding to support opportunistic replacement, and recommends that PG&E provide an analysis in its next GRC if it has evidence that a more aggressive effort is justified.

Cycla observes that PG&E's 2014 forecast does not consider that many regulator replacements could be done when a GSR is at the location to address another issue. Although the forecast volume of regulator replacements increases from about 3,000 (in 2012) to 20,000 beginning in 2014, no efficiency factor is applied to recognize the GSR's time savings that will be introduced reduce the cost increase.

Discussion

We conclude that PG&E's forecast cost is overstated by failing to recognize the efficiency savings, as noted by Cycla. Technical support for PG&E's proposal is a Batelle Applied Energy Systems Report, which notes that such regulators for been used safely with natural gas for periods of over 30 years. PG&E has not

kept track of problems with non-IRV valves, has not kept track of incidents, and does not have any risk analysis supporting its proposal to accelerate the rate of replacement.

Given the lack of a supporting risk analysis, we conclude that PG&E's proposed increase to replace 20,000 commercial-sized regulators that have no internal relief valve is not justified at this time. We conclude that TURN offers a reasonable alternative providing for some increase to support opportunistic replacements as GSRs make site visits to do other work. Accordingly, we approve 25% of PG&E's 2014 forecast increase to support opportunistic replacements of non-IRV regulators.

3.8. Gas Distribution Capital and Investment Planning

PG&E requests approval of a 2014 capital forecast of $531.595 million for gas distribution tools and equipment, pipeline replacement, natural gas vehicles, capacity reliability, leak replacement emergency response, and high pressure regulator (HPR) replacement. The $531.6 million forecast is 141% higher than 2011 recorded expenditures. This forecast includes (a) $331.2 million to increase the rate of replacement of distribution main and associated services from 30 miles per year to 160 miles per year; (b) $128 million for reliability improvements; and (c) $51.1 million for high-pressure regulator conversions.

PG&E forecasts these expenditures by first establishing the level of work required in units of activity (e.g., feet of pipe or number of services replaced), and calculating the unit cost of work activity (e.g., cost per foot of pipeline installed). PG&E calculates most unit cost forecasts based on the prior year's unit cost, adjusted for productivity variances, cost escalation, changes in work complexity, and any changes in activities that define a unit of work.

3.8.1. Gas Pipeline Replacement Program (GPRP)

PG&E forecasts $203.886 million and $331.190 million for MWC 14 pipeline replacement in 2013 and 2014, respectively. PG&E's 2014 forecast is 260% of 2011 spending, and significantly higher than historic pipe replacement. PG&E's GPRP is designed to reduce pipeline leaks and reduce the risk of weld, pipe, or joint failure due to seismic stresses. PG&E argues that just maintaining the current pace of pipeline replacement will not be adequate going forward, but the pace of replacement must increase, or service quality and safety will decline. PG&E proposes significant increases in pipe replacement in MWC 14 and MWC 50, to increase replacement of pre-1940 steel pipe, and pre-1973 Aldyl-A (early Aldyl) pipe.

Beginning in 2014, PG&E plans to replace about 160 miles per year, including doubling steel pipe replacement to 60 miles per year, more than doubling steel pipe replacement costs (to $163 million), and replacing plastic pipe (primarily Aldyl-A) at a similar spending level ($166 million). PG&E plans to replace 34.7 miles of cast iron and pre-1940 steel main, 4,213 copper services and 50 miles of plastic main during 2013 and 60 miles of cast iron and pre-1940 steel main, 250 copper services and 100 miles of plastic main during 2014. For 2014-2016, PG&E plans to replace the remaining copper service population, replace six miles of cast iron and pre-1940 steel pipe and replace 100 miles of plastic pipe annually.

DRA forecasts capital expenditures for MWC 14 of $167.9 million for 2012 based on recorded 2012 amounts; a 2013 forecast of $198.3 million and a 2014 forecast to $215.7 million. DRA agrees with PG&E's estimated units of pipeline replacement for 2013, but applies a lower unit cost. For 2014, DRA assumes annual replacement of 50 miles of pre-1940 steel pipes and cast iron pipes

compared to the 60 miles assumed by PG&E. DRA claims there is uncertainty associated with PG&E's ability to ramp up resources to replace twice the historical levels of cast iron and pre-1940 steel pipes as well as to increase the replacement rate of plastic pipes to 100 miles. DRA claims that its lower forecast is achievable while increasing the rate of pipeline replacement.

PG&E responds that it can complete all forecasted pipeline replacements. DRA's argument for reducing pre-1940 and cast iron pipe replacement assumes that PG&E will also execute on 100 miles of Aldyl-A. Yet, DRA specifically recommends 50 miles of Aldyl-A replacement. PG&E questions how DRA can base a recommendation for pre-1940 steel and cast iron on an assumption that DRA dismisses later in its testimony.

TURN proposes a reduction in capital spending for MWC 14 pipe replacements, from $329 million to $305 million in 2014, redirecting more resources to plastic pipe replacement. TURN claims that risk reduction is achieved more economically by replacing more plastic pipe. Rather than expand steel pipe replacement, TURN thus proposes keeping current steel pipe replacement levels at 30 miles per year and redirecting more money to plastic pipe replacement. TURN also recommends that PG&E conduct an evaluation for the 2017 GRC of its pipe replacement program, and provide data on unit costs and leak reduction by pipe category. Based on the results of the analysis, TURN proposes that PG&E redirect spending where it can pursue greater risk reduction with pipe replacement funds, including spending on activities other than pipe replacement.

PG&E has historically replaced about 30 miles of pre-1940 steel pipe per year. For pre-1940 steel pipes, an annual replacement rate of 60 miles would be needed for 15 years to bring the leak rate down to system average. For Aldyl-A

pipe, PG&E needs to replace 100 miles per year for 15 years to decrease the leak rate to the system average.

PG&E proposes to continuously re-evaluate the leak rate trend and other risk factors to ensure the right number of miles will be replaced to decrease the leak rates to the system-wide average and to otherwise reduce risk. Certain pipe materials have higher leakage rates compared to the system average. PG&E will utilize leak history, along with other factors, like seismic susceptibility, for prioritizing the highest risk pipe for replacement It expects to replace the population of pipe materials based on current performance of pipe materials. Beginning in 2014, PG&E proposes to replace 180 miles of distribution main per year.

PG&E argues that is unrealistic and unreasonable to expect it to identify all capital projects with specificity in order to conclude that projects are needed or will be performed. PG&E described the methodology by which specific segments will be identified for replacement. As of June 2013, PG&E identified all Aldyl-A and GPRP projects for all divisions except San Francisco, which takes longer to scope.

Replacing plastic pipe eliminates more leaks because the pre-1973 Aldyl-A pipe leak rate is 37% higher than the leak rate for pre-1940 steel pipe. PG&E has had three major distribution pipe explosions in 2009 and 2011 all of which involved Aldyl-A pipe.

PG&E proposes that steel and plastic pipe replacement receive nearly equal amounts of funding from 2014 through 2028. Given data on leak rates and replacement costs, PG&E's strategy of doing everything at once diverges from a strategy focused primarily on reducing risk.

PG&E claims it cannot completely prioritize pipe replacement based on a risk assessment until all relevant information has been digitized. TURN assumes that the next riskiest segment of pre-1973 Aldyl-A pipe leaks more than the highest risk pre-1940 steel pipe. PG&E claims there is no evidentiary support for this assumption. PG&E also claims that leak rate is only one factor in determining the right pipe to replace. Risk is the product of the probability of failure and the consequence of failure. The leak rate is relevant only to the probability of failure, not consequence, and is not the only factor relevant to probability.

Discussion

We adopt a capital expenditure forecast for MWC 14 for 2012 based on recorded spending of $167.869 million, as proposed by DRA. We adopt a 2013 forecast of $203.886 million, as proposed by PG&E. We decline to adopt DRA's proposed unit cost reduction for Aldyl-A pipe replacement. As noted by PG&E, DRA's unit cost did not compare the correct scope of work.

We are not persuaded that PG&E's proposed replacement program reflects the most optimal safety mitigation results in relation to the costs involved. Replacing pipe that has higher leak rates is PG&E's principal method of reducing the distribution system leak rate. PG&E, however, provides no information to explain its choice between plastic versus steel pipe replacement, but forecasts doubling the steel pipe replacement rate. Risk assessment for pipe replacement is driven by the risk of failure (reflecting material properties and corrosion impacts) and the consequence of failure (reflecting population density near the pipe).

Cylca concludes that although PG&E proposes a significant increase the rate of pipeline replacement, it has not developed a risk-informed position on the

optimal rate of pipeline replacement. The only constraint PG&E applied is its ability to increase staffing to support the rate of replacement. PG&E provided no evidence of a need to double the pace of steel pipe replacement. PG&E's GPRP targeted the steel pipe located in populated areas and near seismic risks. PG&E has already replaced all but 80 miles of this high risk steel pipe. TURN argues that there is no need to accelerate steel pipe replacement even if steel pipe was the dominant material installed in San Francisco and Oakland. We adopt a 2014 capital forecast for distribution gas pipeline replacement $305.858 million (composed of $230.451 million for Aldyl-A, $73.561 million for steel, and $1.846 million for copper pipe), based on TURN's proposed pipeline replacement proposal. Our adopted forecast thus provides for steel pipe replacement levels at 27 miles per year and redirecting more money to plastic pipe replacement. TURN calculates that increased spending on Aldyl-A replacement, while holding steel pipe replacement constant at 2011 levels, saves over $48 million/year from 2014 through the attrition years, while achieving a system leak rate comparable to PG&E's proposal. We adopt TURN's recommendation to apply half of these cost savings to additional plastic pipe replacement.

We conclude TURN's proposal provides a reasonable balance between containing cost increases while mitigating pipeline safety risk. TURN's proposal results in TY 2014 capital spending that is 241% above 2011 levels, but reduces PG&E's 2014 forecast by $25.3 million.

TURN's forecast provides for replacement of 27 miles of steel pipe and 139 miles of Aldyl-A pipe, for a slightly higher total mileage rate of replacement. Plastic pipe costs less per mile to replace. The 2014 forecast cost for plastic pipe is $314/foot, versus $516/foot for steel pipe. The plastic pipe's higher leak rate and lower cost of replacement means that replacing pre-1973 Aldyl-A pipe

provides a 125% greater risk reduction per mile at a lower cost. About $75 million a year remains for replacing steel pipe.

By maintaining a comparable rate of steel pipe replacement, TURN's proposed funding is sufficient to replace high priority value steel pipe within three years, faster than the replacement rate for plastic pipe. PG&E can thereby continue to pursue high risk steel pipe, while focusing on high risk plastic pipe. PG&E should focus on eliminating pipe with the highest priority value in terms of safety risk mitigation.

Although PG&E's actual replacement practices may be based on a variety of risk factors, including seismic impacts and proximity to densely populated regions in implementing pipeline replacements, PG&E's GRC forecast of pipeline replacement costs does not quantify the impacts of such factors other than leak rates.[26] Thus, PG&E's pipeline replacement forecast doesn't provide any additional accuracy compared to TURN's in correlating costs with safety risk factors.

Cycla concludes that PG&E's per-unit costs for pipeline replacements "seem high," especially considering that replacements will be disbursed geographically including the Central Valley and not limited to San Francisco. Aldyl-A pipe replacement has a lower average unit cost which is primarily a function of its location. Pipe replacement in urban areas costs more as these areas have a higher volume of steel. The lower unit cost of Aldyl A pipe correlates with pipe replacements outside of densely populated urban areas. PG&E's forecast costs are nearly $200 per foot higher than most pipeline

[26] TURN Opening Brief at 66-73.

replacement costs on the East Coast. Cycla suggests the use of competitive bidding by outside contractors, particularly for low-skilled work, as one way to lower PG&E's costs. PG&E crews currently perform all main installations. We expect PG&E to follow up on Cycla's suggestions for cost efficiencies in implementing pipeline replacements.

DRA also recommends a ratemaking mechanism for MWC 14 that allows PG&E to request, through a Tier 1 advice letter, recovery of 2014 recorded capital expenditures in excess of $215.7 million but not to exceed PG&E's forecast of $331.2 million. Since we are adopting a higher funding amount than DRA proposes, we are not persuaded that a Tier 1 advice letter process is necessary.

3.8.2. Gas Distribution Reliability (MWC 50)

PG&E forecasts $62,707, $72.439 and $128.1 million in 2012, 2013, and 2014, respectively, for Gas Distribution Reliability (MWC 50), for capital installation or replacement of aging gas facilities to improve system safety and reliability, to replace aging facilities, and to maintain compliance with safety regulations. Planned activity includes replacement of mains and services, regulator stations, and CP anodes, and installation of emergency zone shutdown valves. Replacements include facilities with a relatively high likelihood of failure or that have failed.

PG&E's forecast includes $27.818 million in capital for 2014, and similar amounts in 2015-2016 to complete the installation of emergency shut down valves in three years, accelerating from no installations in 2013 to over 1,000 per year during 2014-2016.

DRA recommends using the recorded figure of $69.326 million for 2012 and accepts PG&E's 2013 forecast. DRA proposes a reduction of $55.6 million to PG&E's 2014 forecast, however, by using PG&E's 2013 forecast for 2014. As with

MWC 14, DRA recommends an advice letter process for recovery of these costs. DRA bases its recommendations on: (1) uncertainty regarding PG&E's ability to replace pipes at forecast levels, (2) no listing of all gas distribution pipes to be replaced, (3) PG&E already complies with Utility Standard 5000 and Federal and State safety code requirements for emergency shutdown zone requirements, (4) PG&E cannot identify where new emergency zone shutdown valves would be installed, and (5) maintaining a leak survey cycle of five years.

DRA disputes PG&E's forecast because PG&E did not specify basic information such as locations for new shut-off valves to be installed and factors used to choose such locations. PG&E argues that the lack of identified specific locations does not render its forecast unreasonable, and that it is not realistic to have all of that information so far in advance of completing the actual work.

TURN recommends reducing PG&E's 2014 forecast by $15.96 million; $2.051 million of which is based on a five-year leak survey cycle, which reduces PG&E's capitalized service replacements. TURN also recommends reducing PG&E's forecast for installation of emergency zone shutoff valves by half, or $13.909 million, spreading this work over six years, rather than the three years PG&E proposes.

TURN recommends that the program and costs be implemented over six years rather than three years, as PG&E proposes, to avoid resource constraints and conflicts with other high priority replacement initiatives. PG&E responds that it is coordinating the work and this efficiency is built into PG&E's forecast unit costs.[27]

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[27] Exh. 53 at 8-22, lines 6-14.

TURN believes that installing the valves over six years, using the current planning process to focus work in areas posing the greatest risk of an emergency, will smooth spending, and create less competition for resources shared with other safety initiatives that also are rapidly expanding spending.

PG&E argues that it is not clear what risk analysis TURN thinks PG&E should or could perform. The risks are known and understood.

Discussion

We conclude that PG&E's scope of activities for gas distribution reliability expenditures for MWC 50 mitigate known safety risks. For 2012 capital expenditures, we adopt DRA's recommendation to use the recorded figure of $69.326 million. For 2013, we adopt PG&E's capital expenditure forecast. Consistent with our adoption of funding based on a five-year leak survey cycle, however, we reduce PG&E's capital expenditure forecast for MWC 50 by $2.051 million for 2014, as calculated by TURN, except for a $15.96 million reduction to extend the planned installation of emergency shut down valves over six years, instead of three years, and to reflect a five-year leak survey cycle. In all other respects, except for these adjustments, we adopt PG&E's MWC 50 capital forecast for 2014.

PG&E's plan to increase installations of emergency shut-down valves is consistent generally with SB 705. Although PG&E is in compliance with Utility Standard 5000 and Federal and State safety code requirements for emergency shut down zone requirements, PG&E's plan is designed to bring it into compliance with industry best practices as required by SB 705.

Increased installations of emergency shut-down valves reduce emergency response times and reduce the number of customers impacted during a major event. Based on our judgment, the mitigation of system safety risks warrants

increased funding. We question, however, PG&E's proposed timetable for implementation. PG&E has not supported its rate of installations from zero to over 1,000 valves per year based on an explicit risk assessment in relation to the relative cost, or quantifying the benefits to customers of implementing installations over three years versus a longer period in relation to the costs. Although PG&E claims that it can adequately coordinate this increased work load with other planned activities, we also remain concerned regarding PG&E's capabilities to absorb such large increases over a three-year GRC cycle. Our concerns are supported by the study conducted by Cycla. Cycla states that the basis for PG&E's cost estimate for this program is unclear and without more specifics, it is difficult to evaluate the appropriateness of PG&E's cost estimate.

PG&E's proposal for additional emergency zone shutoff valve installations is intended to meet industry benchmarking showing that more valves (i.e., fewer customers per zone) is an industry best practice. SB 705 requires a plan to achieve best practices to "[p]repare for, or minimize damage from, and respond to, earthquakes and other major events." While SB 705 requires that a plan be implemented, it does not dictate the specific timetable for phasing in emergency zone shut-off valve installations.

Weighing these factors, we approve PG&E's proposal to install emergency shut-off valves, but reduce PG&E's forecast 2014 funding level to reflect implementation over six years, rather than three. Extending the implementation over six years mitigates impacts on customers of absorbing such a large cost increase, and alleviates pressure on PG&E's ability to fund competing resources and high-priority programs.

We decline to adopt DRA's proposed 2014 forecast. DRA fails to justify relying on the 2013 forecast as a basis for 2014 activity. We will not require

PG&E to specifically identify the locations where the valves will be installed. As PG&E notes, such a requirement could lead to undue work delays if it could not get funding approved for work it should do unless it had first completed full engineering review by the time it filed its GRC. Although PG&E cannot identify precisely where the new emergency zone shut down valves would be installed, that level of precision is not necessary to conclude the aggregate level of planned installations is reasonable.

DRA recommends that PG&E be permitted to request recovery of its 2014 recorded expenditures in excess of DRA's 2014 forecast of $72.439 million, but not to exceed PG&E's forecast for MWC 50. Since we are adopting a forecast higher than DRA's proposal, we find no necessity to authorize advice letter treatment for MWC 50 costs.

3.8.3. Gas Distribution HPR Replacement

PG&E forecasts $42.0 million in 2012, $50.0 million in 2013, and $51.2 million in 2014 for Gas Distribution Leak Replacement/HPR Replacement. HPRs, commonly referred to as "Farm Taps," are small diameter regulator sets served off of a transmission pipeline. In 2011, the majority of leaks on the gas transmission system were on HPR facilities. PG&E has committed to replacing the 4,700 HPR sets.

DRA recommends $1.2 million in each 2012, 2013, and 2014 for expenditures relating to replacing HPR sets based on recorded 2010 capital expenditures. DRA recommends that rebuilding and replacement of HPR-Type stations be recorded as gas transmission capital expenditures and not as gas distribution capital expenditures in PG&E's 2014 GRC. DRA does not oppose PG&E's proposed regulator replacements for 2013 and 2014, but bases its

recommendation on a lower unit cost. DRA recommends a 2014 forecast of $3.9 million.

DRA proposes to reduce PG&E's forecast for HPR sets, by $49.9 million for 2014, which is a 98% reduction. DRA's main support for this argument is that HPRs are Transmission assets, not Distribution, based on the PHMSA transmission definition of operating above the 20% Specified Minimum Yield Strength.

Discussion

We conclude that PG&E's forecast for HPR replacement is reasonable and adopt it. As PG&E explains, regardless of the technical definition under PHMSA, PG&E has always treated these assets as Distribution assets for ratemaking purposes. The forecast work related to these HPRs is analogous to maintenance, installations, and upgrades of District Regulator Stations that regulate pressure from transmission down to distribution and are considered distribution assets. The majority of these costs are accounted for within MWC 50 (Reliability), MWC 47 (Capacity) and MWC FH (Preventative Maintenance).

3.8.4. Tools and Equipment (MWC 05)

PG&E forecasts $2.6 million for 2014 for MWC 05, Tools and Equipment. The forecast covers the replacement of damaged, worn-out, or obsolete tools and to provide specialized tools to perform testing and other analytical functions performed by field work employees. DRA proposes a reduction of $1.38 million, based on a five-year average (2007-2011) of historical expenditures.

We approve PG&E's forecast for MWC 05 for tools and equipment. We conclude that the use of a five-year historical average fails to reflect the higher volume of work and increased headcount that is expected during 2014, compared to the historical period. Cycla states that the increased spending on

tools and equipment has a minor effect on reducing risk, but will facilitate other expenditures needed to improve overall gas system safety.

3.9. NB and Work at the Request of Others

PG&E forecasts 2014 capital expenditures of $83 million (in MWC 29) to cover installation of infrastructure to connect new customers to the gas system and to accommodate increased load from existing customers. DRA disputes PG&E's 2014 capital expenditures forecast of $83 million, based on a residential new customer connect growth rate of 62.5% in 2014, claiming it is excessive compared to the 2007-2012 capital expenditures for MWC 29.

PG&E forecasts $39 million for 2013 and $45 million for 2014 for the capital cost of relocating existing gas distribution and service facilities at the request of governmental agencies or other third parties. DRA agrees with PG&E's forecast of capital expenditures of $39 million in 2013 and $45 million in 2014 covering "Work at the Request of Others" (MWC 51).

PG&E forecasts residential new customer connect growth of 53% for 2013 and 62.5% for 2014 based on regional building permit data from Moody's Economy.com and IHS Global Insight. PG&E forecasts 20,449 overall residential new connections in 2013 and 33,228 in 2014. PG&E forecasts 2,342 overall non-residential new connections in 2013 and 2,551 in 2014. PG&E's unit cost forecast for residential and non-residential work (except for residential subdivision backbone work) uses a three-year historical average for each forecasting component, escalated to current year dollars. PG&E applied a correlation formula to calculate residential subdivision backbone component unit costs.

DRA recommends a reduction of $12 million for MWC 29 in 2014, by applying the 2013 forecast capital expenditures to forecast for 2014. This is the

equivalent forecasted increase of capital expenditures from 2012 recorded capital expenditures to the 2013 forecast for MWC 29. DRA's lower figure is due to uncertainty associated with future economic conditions and how they will impact customer growth.

Discussion

We adopt PG&E's forecast for new customer connections. DRA's proposed reductions appear to lack support. DRA identifies no methodological error in PG&E's calculations of new customer connections. DRA offers no basis for assuming that a forecast lower than PG&E's is necessarily more conservative. We find PG&E's forecast reasonable.

3.10. Technical Training and Research and Development

PG&E forecasts technical training development expense of $12.69 million (MWC AB) and $2.5 million for Research & Development (R&D) and Innovation activities (MWC GZ) to identify new or improved means of enhancing operation, safety and efficiency. This includes $802,000 for collaborative R&D and $1.698 million for staff and contractor support. The R&D and Innovation Program is organized to optimize the use of external resources and to facilitate adoption of emerging technologies.

Key objectives are to (1) identify, evaluate, adapt and introduce new technologies and solutions, (2) expand and strengthen knowledge and understanding of equipment, and (3) develop a proactive approach to identify challenges and apply innovations to improve methods and tools. PG&E developed the program based on a benchmarking study and the hazards identified by the Commission's Risk Assessment Unit to bring the training program in line with industry best practices. The Gas Distribution R&D and Innovation program provides the ability to research changes and enhancements

in the gas operations industry and determine appropriate actions to benefit gas customers. Training cost estimates are based on the number of courses and anticipated staffing. R&D estimates are based on industry practice with selected R&D implementers.

DRA recommends reducing PG&E's technical training forecast by $8.81 million, or 70%. For R&D and innovation, DRA recommends reducing PG&E's forecast by $982,000, or 40%. DRA recommends that PG&E's forecast be set at the 2012 recorded level, without escalation. DRA claims that there is "embedded" funding for this work in other MWCs.

PG&E argues that adopting DRA's recommendation would prevent technical training improvements, as required by SB 705. PG&E agrees there is funding for training embedded in other MWCs, but claims this funding is adequate only to continue technical training at historical levels, not to enhance that training, as recommended in PG&E's 249 page benchmarking study. PG&E, Engineers and Scientists of California (ESC) and Cycla agree that the enhanced training is important.

Discussion

We approve PG&E's proposed forecast for technical training and R&D. Limiting funding to 2012 levels would fail to support the incremental funding necessary to cover enhanced levels of training beyond the limited scope of training that is covered through embedded funding. The enhanced training is also necessary to address hazards identified by the Commission's Risk Assessment Unit of the SED. Funding this enhanced training program should improve system safety and reduce risk of hazards caused by inadequately trained employees.

3.11. Gas Operations Information Technology (IT) and Infrastructure Costs

PG&E's Gas Operations IT portfolio is designed to improve safety, compliance, productivity, execution, customer satisfaction and system integrity. The gas operations IT portfolio includes the following:

- Gas Distribution Asset Management: Pathfinder Project; Estimator Toolset Enhancements, Including Graphic Work Design Tool; Compass Enablement; Technical Information Library Re-Platform; and GEMS Re-Write;
- Public Safety and Integrity Management: DIMP Information Technology Enhancements; Public Safety Initiatives; New Regulatory Reporting Requirements; and Back-Up Radios for Gas Service Representatives;
- Gas Operations: Gas Control Center Radio System; Gas Control IT Applications; Pipe-to-Soil Monitors; and Gas Operations Information Technology Enhancements; and
- Mobile Platform for Long-Cycle and Short-Cycle Work; Mobile Extension and Enhancement to Additional Crews; Mobile Device Replacement/Upgrade; Mobile O&M Leak Survey, Repair and Replacement; First Responder Portal; Upgrades to the Field Automation System (FAS) Interface for Gas Distribution; and Testing and Conforming Applications to Vendor Upgrades.

PG&E's 2014 forecasts Gas Operations' technology expenses in MWC JV of $19.244 million. DRA recommends reducing PG&E's 2014 expense forecast by $8.433 million, including a $6.9 million reduction for the Pathfinder Project. TURN recommends reducing PG&E's expense forecast by $2.941 million based on DRA's proposed 14% disallowance of costs using PG&E's Concept Cost Estimating Tool, and based on no funding for PG&E's mobile extension and enhancement program or PG&E's mobile device replacement and upgrade program.

PG&E's forecast for capital expenditures related to Gas Distribution IT Projects in MWC 2F compared with DRA's forecast is detailed in Table 10-43 of Exh. DRA-10, page 64, and summarized as follows:

$ in Millions

	PG&E	DRA
2012	$26.919	$12.506
2013	$27.725	$11.115
2014	$43.722	$11.617

DRA recommends reducing PG&E's 2012 forecast to reflect recorded expenditures. We resolve parties' disputes relating to MWF 2F forecasts below.

3.11.1. Path Finder Project

PG&E forecast includes $16.69 million in 2014 capital expenditures and $10.3 million in 2014 expense for the Pathfinder Project which is designed to convert gas distribution asset and maintenance information from legacy and paper-based systems to the Systems, Applications & Products (SAP) and GIS systems. Pathfinder is a tool to improve the safety and reliability by installing tools to enable the electronic collection, processing, review, analysis and integration of distribution records. Pathfinder builds upon the gas transmission asset management project utilizing mobile technology to convert paper-based processes to electronic format.

DRA recommends reducing PG&E's 2014 capital and expense forecast for Pathfinder by $13.69 million and $6.91 million, respectively. DRA recommends slower implementation and normalizing PG&E's $10.3 million expense forecast over a three-year period, thereby setting the 2014 forecast at $3.4 million. DRA claims that PG&E has not shown that the data conversion needs to happen

within a three-year time frame. DRA also argues that 2012 spending levels support its 2014 forecast.

PG&E contends that delaying the Pathfinder Project would impede its ability to perform quantitative risk analysis and move toward more risk based investment planning. PG&E claims that adopting DRA's recommendation would reduce spending on this project to 25% of the monthly spending at the end of 2012 and would delay completion of the project until 2022.[28]

Discussion

We approve expense funding for PG&E's Pathfinder Project for 2014, except for a reduction by $$1.442 million based on DRA's disallowance for use of the Concept Cost Estimating Tool, as discussed at Section 7.8. For 2012 capital spending, we adopt DRA's recommendation to use the 2012 recorded amount of $3.081 million. For 2013 and 2014 capital spending, we adopt PG&E's forecast, except for a reduction of 14% based on DRA's disallowance for use of the Concept Estimating Tool. PG&E's forecast timeline for Pathfinder is aligned to support decision making and analytics for programs and departments that impact public safety. Data conversion planned as part of the project is prioritized using a risk-based approach to address areas that could potentially present the largest risk. If PG&E does not implement the Pathfinder Project on its planned schedule, it could negatively impact its ability to successfully implement robust integrity management. Given the integral importance of the Pathfinder Project, we do not adopt DRA's recommendation to slow down the implementation. Cycla concludes that PG&E's documentation to support

[28] *See* PG&E Opening Brief, Section 3.11.1.3.2.

staffing to implement Pathfinder appears reasonable. Our reduction in the forecast is intended to recognize the risk of forecast error inherent in the use of the Concept Estimating Tool.

3.11.2. Back-up Radios for Gas Service Representatives

PG&E forecasts $8 million in capital expenditures in 2014 to purchase a back-up radio system for GSRs. SB 705 requires that PG&E implement a plan to "[p]rovide for timely response to customer and employee reports of leaks and other hazardous conditions and emergency events" and that the plan be "consistent with best practices in the gas industry." PG&E argues that having backup radios for GSRs is an industry best practice.

GSRs are PG&E's emergency first responders, staffed and scheduled to be able to respond to emergencies within 30 minutes 75% of the time and within 60 minutes 99% of the time. GSRs are trained to investigate gas odors inside structures, including homes. For PG&E to provide a timely response to an emergency, such as a report of a gas odor inside the customer's home, PG&E must be able to communicate with its GSRs. DRA recommends zero funding for this project, claiming that GSRs do not need backup radios. DRA claims GSRs already have several options for communication without the backup radios.

Discussion

We approve PG&E's forecast for the back-up radios for GSRs, except for a reduction of 14% to reflect use of the Concept Estimating Tool, as proposed by DRA. Cycla also believes that the documentation for this technology improvement appears reasonable. The back-up radio project will provide GSRs, dispatch operators and their supervisor's access to a private mobile radio system. Deploying radio communication equipment will allow GSRs and dispatch

operators to communicate during emergencies when the existing cellular system is congested and in geographic areas where the cellular coverage is unavailable or not robust.

3.11.3. Mobile Platform Technology Solutions

PG&E forecasts $10.7 million for 2014 capital expenditures and $2.1 million 2014 expense to deploy mobile platform technology solutions and support for gas distribution work crews. The platform includes: (1) long-cycle and short-cycle work; (2) mobile extension and enhancements to additional crews; (3) mobile device replacement/upgrade; (4) mobile O&M leak survey, repair and replacement; and (5) a first responder portal.

PG&E's mobile platform technology supports the migration from paper based to electronic based systems for the gas distribution workforce. Cycla concludes that the scope of PG&E's Gas Operations IT projects is "consistent with practices employed by best operators, and that the proposed activities reflect a reasonable activity phase-in rate." We conclude that PG&E's proposed expenditures do not duplicate other programs, and that the benefits of the program justify the costs. The rollout is to ensure a larger group of crew members are available to receive electronic notification of emergencies or other work, especially as crews subdivide or re-group in different formations.

PG&E forecasts $1.54 million for 2014 capital expenditures and $144,000 in expense for mobile for long-cycle work where crews are dispatched to a work location for multi-day projects. This initiative involves installing mobile devices and communications equipment in the trucks assigned to long-cycle work crews. By reducing paper-based processes, field crews will be able to access data more quickly and enter data directly with reduced error risk. The effort required to

automate the long-cycle work processes generally involve updates to asset information in SAP and GIS.

DRA recommends a $950,000 reduction for mobile long cycle work, assuming a cost of $1 million to upgrade FAS and configure Ventyx, GIS and SAP, claiming that some software applications modifications for other mobile devices are applicable to the long cycle mobile devices.

PG&E forecasts $400,000, $1.6 million, and $3 million of capital expenditures for mobile for short cycle work for 2012, 2013, and 2014, respectively. DRA agrees with PG&E's 2012 figure, but proposes only $600,000 for 2013 and 2014, reducing PG&E's forecast for those years by $3.4 million. Short-cycle crews typically consist of two persons assigned to work that can be completed within a short time frame. This initiative will install mobile devices and communications equipment on crew trucks and configuring systems so that PG&E can schedule and optimize field resources. Dispatchers can track crew more efficiently and can provide customers more accurate time estimates for completing jobs. The effort required to automate the long-cycle work processes generally involve updates to asset information in SAP and GIS.

Discussion

We adopt recorded expenditures as the 2012 forecast, as proposed by DRA. We adopt PG&E's 2013 and 2014 capital and 2014 expense forecast for mobile long cycle and short cycle work, but reduced to reflect DRA's proposed 14% disallowance for use of the Concept Estimating Tool.

PG&E explains that previous programming work done for the mobile application for leak survey and locate and mark processes cannot be reused for the long cycle project. In the leak survey process, information is captured on an exception basis. The applications for leak survey and locate and mark were built

on a different platform and for different devices than the work being done on the mobile platform and with Ventyx. The leak survey and locate and mark work involves one person, not a crew, performing different work than long cycle crews.

PG&E claims that the work for the short-cycle platform will cost more, not less (as DRA recommends), than the work for the long-cycle platform because there are more work processes to be modified. We find no basis to conclude that the work for the short-cycle platform is duplicative of the work for the long-cycle platform.

3.11.4. Mobile Extensions and Enhancements

PG&E forecast $1.8 million in capital expenditures in 2014 for its mobile extension and enhancement to additional crews program. The additional funding will extend PG&E's other mobilization efforts to additional crew personnel (including Title 200 and Title 300 crews) who do not have mobile devices. PG&E claims that the rollout is required to ensure a larger group of crew members are available to receive electronic notification of emergencies or other work, especially as crews subdivide or re-group in different formations.

DRA recommends no funding for this work, stating that the additional crew members do not need the mobile devices, and that PG&E has not shown the benefits of providing a mobile device to each of the crew members that are in the same truck. DRA believes that crew members can adequately communicate by use of existing laptops in addition to the new mobile devices proposed in the Long-Cycle and Short-Cycle Mobile Projects. TURN also recommends no funding based on TURN's opinion that providing additional devices could counterproductively make data management and quality control more difficult and expensive.

Discussion

We conclude that PG&E has adequately justified the funding for its mobile extension and enhancement to additional crew. We adopt PG&E's forecast for this program. As PG&E explains, the intent of this program is to provide one device at each job site, but not to provide a device to all personnel in the field. The mobile devices will generally be assigned to each crew foreman and installed in that person's truck resulting on one device at each job site. The additional devices will be provided to workers in multi-person crews, allowing the crew members to have more than one device per crew for when the crew needs to be split into smaller groups or when a crew member has been temporarily rotated into a supervisor role. Our approval of this funding is in accord with Cycla's finding that PG&E's "[m]obile platform technology supports the migration from paper based to electronic based systems for the gas distribution workforce," that the scope of PG&E's Gas Operations IT projects is "consistent with practices employed by best operators," and that "the proposed activities reflect a reasonable activity phase-in rate."[29]

3.11.5. Mobile Device Replacement/ Upgrade Project

PG&E forecasts 2014 capital expenditures of $1.875 million for mobile device replacements and upgrades, rolling out mobile technology to approximately 780 personnel. This initiative is to enable more of the workforce to use mobile equipment and obtain productivity gains. PG&E claims that the collection of information directly from crews performing the work while at the

[29] Exhibit 167, Cycla Report at 38-39.

job site is an industry best practice. Implementing this project will bring PG&E in line with industry best practices and improve PG&E's data validation.

DRA recommends no funding arguing that this initiative duplicates PG&E's lifecycle replacement program, and that the additional crew members do not need the mobile devices.

PG&E responds that this program is not to replace assets at the end of their lifecycle, but to ensure that mobile devices assigned to users meet the requirements of their job duties. PG&E claims that DRA's recommendation would prevent optimization of the technology portfolio.

TURN also recommends no funding, arguing that the additional 780 units are far in excess of what is needed for 300 crews. TURN believes that providing additional devices could actually make data management and quality control more difficult and expensive. PG&E responds that mobile devices let workers document work as soon as practical after a job is complete while the job is still fresh, rather than trying to recall attributes of a project after the fact.

TURN claims this program duplicates other programs. TURN's proposed disallowance is independent of whether these devices include phones. TURN claims this is an excessive request to cover mobile upgrade needs of 300 gas crews since PG&E is already purchasing new mobile units for these crews.

Discussion

We are persuaded by DRA and TURN that PG&E's proposed funding of $1.875 million for 780 additional mobile devices for 300 crews has not been justified, particularly in view of the new mobile units we are already authorizing for long and short cycle work. While providing these additional devices may enable more of the workforce to use mobile equipment, we are not persuaded that PG&E has justified that any benefits are sufficient to offset the burden on

ratepayers relating to these additional expenditures. We decline to authorize additional funding for this request.

3.12. Building Projects, American Gas Association (AGA) Fees, and Publicly Available Standard (PAS) 55 Certification (MWC AB)

PG&E forecasts for Gas Operations buildings projects, AGA dues and Publicly Available Standard (PAS) 55 certification costs. PG&E's MWC AB expense forecast is $6.5 million, consisting of $5.7 million for buildings projects, $300,000 for AGA dues and $500,000 for PAS 55 certification expenses. DRA proposes expense reductions of $4.14 million, and TURN proposes reductions of $2 million.

PG&E also forecasts $50.628 million in 2014 capital expenditures (MWC 78) that includes 12 major building projects, consisting of a new headquarters office, a control center, a backup control center, a training center, and various other service and office spaces. DRA proposes capital expenditure reductions of $15.916 million to PG&E's MWC 78 forecast. Cycla states that "[t]he new gas control center, the 'hot' backup control center, and the new training facility are consistent with practices employed by the best gas distribution (GD) operators."

TURN argues that the Commission should disregard Cycla's evaluation of PG&E's requested funding for gas operations buildings since Cycla did no analysis of PG&E's cost estimates nor compare the costs to other estimates used for similar products. Cycla made no effort to determine if the unit cost was credible or reasonable. Cycla read PG&E's workpapers, copied project descriptions from those workpapers, and concluded that, because PG&E used a unit cost and multiplied that unit cost against the units to obtain a final dollar figure, the cost estimate was reasonable.

3.12.1. Gas Operations Headquarters Building

PG&E forecast $1.66 million in 2014 expense for a new consolidated headquarters office in San Ramon to accommodate increases in engineering, operations, construction and technical staff. PG&E forecasts capital costs for the new headquarters building in MWC 78. PG&E's capital forecasts for MWC 78 compared with DRA and TURN are:

	($000s)		
Year	PG&E	DRA	TURN
2012	$16,405	$8,886	$11,591
2013	$3,054	$2,463	$2,583
2014	$2,490	$2,490	
Totals	$22,546	$13,839	$14,174

PG&E's capital forecast is based on allocating 80.65% of project costs to distribution and 19.35% to transmission. PG&E calculates these ratios based on its common plant allocation process which uses recorded labor ratios. Approximately 75% of all Gas Operations employees are classified as distribution.

DRA recommends reducing PG&E's capital forecast by $8.1 million, substituting 2012 actual costs for PG&E's forecast. PG&E objects to DRA's reduction, arguing that it fails to account for the full forecast cost over the 2012-2014 period for the headquarters building. Although 2012 spending was lower than forecast due to project delays, PG&E still expects to complete the headquarters project by 2014. As a result, PG&E contends that the unspent money forecast for 2012 is still needed to finish the total project by 2014. Yet, DRA makes no provision in its 2013 or 2014 forecast to recognize this make-up in previously forecasted 2012 spending.

TURN recommends reducing PG&E's 2014 expense forecast by $1.13 million, and capital forecast by $17.5 million based primarily on a recommendation to allocate 27% of costs to distribution, and 73% to transmission based on the ratio of distribution and transmission employees at the new headquarters building.

PG&E disputes TURN's calculation as representing a single point in time at a time while people were still moving in, and that is not representative of distribution/transmission employee ratios once the building is fully occupied. The headquarters was not fully staffed when TURN made its evaluation. The overall number of employees scheduled to move to the headquarters has increased since that time, and a large number of the employees who had not yet moved were distribution employees.

PG&E has 42,000 miles of distribution main and 3.3 million distribution services, but only 6,750 miles of gas transmission pipe. Comparing just main, transmission pipe represents only 14% of the system. If services are counted, the percentage is 8.6% (PG&E's 3.3 million distribution services add another approximately 30,000 miles of pipe to the system).

Discussion

Although no party disputes the merits of adding the new headquarters building or the total building costs, we have two concerns regarding PG&E's capital forecasts: 1) the overall project timing and end date; and 2) the allocation of common cost between the transmission and distribution departments.

We first address project timing as a factor in the forecast. PG&E acknowledges that the lower than forecast 2012 capital expenditures were due to project delay. We agree with DRA that PG&E's 2012 capital forecast should reflect actual costs; thus, we adopt PG&E's recorded 2012 spending of

$8.886 million for the total 2012 capital costs. We agree with PG&E that 2013-2014 capital forecasts should be adjusted to reflect the underspent funds from 2012. Accordingly, we apply the underspent funds from 2012 of $7.519 million (=$16.405 - $8.886 million) as an addition to the 2013 capital forecast.

Although the headquarters building will be shared between transmission and distribution employees, we share TURN's concerns with PG&E's allocation calculating of common costs. A reasonable basis for allocating common headquarters building costs for ratemaking purposes is the ratio of gas distribution employees expected to occupy the building in relation to gas transmission employees. The ratio of miles of physical transmission versus distribution pipeline facilities offers a less direct cause-and-effect relationship to assess how the headquarters building will be utilized and how to allocate between distribution and transmission functions.

We conclude that PG&E's allocation of 81% of the headquarters building costs to distribution is excessive, in terms of the use of the building for gas distribution purposes. However, we find TURN's allocation of 27% to distribution too low to the extent that it does not account for the ratio of distribution employees after the building is fully operational. At full capacity, PG&E expects 865 full time employees with 520 dedicated to gas transmission. This mix would support an allocation of no less than 60% to transmission and no greater than 40% to distribution. Therefore, we adopt a forecast for the distribution allocation of costs for the headquarters building of 40% to distribution based on TURN's calculation of the ratio of employees occupying the building assuming remaining vacancies are filled by distribution employees.

Based on the above discussion, we authorize PG&E's capital costs for the new headquarters building to distribution as follows: $3.55 million for 2012, $4.23 million for 2013 and $1.23 million for 2014.

3.12.2. Gas Control Center

A new Control Center will be co-located with a new gas dispatch center and transmission control system on the fifth floor of its San Ramon facility. The Control Center is to directly support the goal of attaining zero public and employee safety incidents. Forecasted capital expenditures are for installation of devices, related software, and supporting telecommunication radio system assets to monitor and control pressures and flows in the gas distribution system. PG&E plans to operate the Control Center as a centralized, real-time distribution monitoring and control system analogous to its existing transmission system. The Control Center will provide diagnostic capabilities to keep the system working normally and prevent safety-related events. If an accident does occur, the Control Center and dispatch function will enable faster response and more robust mitigation. PG&E identifies three overarching risks facing gas distribution operations: (1) gas leaks, (2) gas supply and service loss, and (3) inadequate response and recovery.

For its new gas control/dispatch center, PG&E forecasts renovating the existing building at a total capital cost of $21.1 million.

DRA does not oppose PG&E's proposed Control Center and installation of monitoring and control devices on the gas distribution system, but claims that PG&E's 2012-2014 forecast is overly optimistic in view of the permitting and system operations issues and potential implementation schedule.

PG&E disagrees with DRA's proposed forecast reductions. DRA recognized the reduced spending from 2012, caused by project delays, but

proposed no corresponding spending increases to make up for that delay in 2013 or 2014. PG&E claims, however, that 2012 reduced spending was due to temporary project delay, not to any reduction in the overall forecast cost. PG&E claims that work that was delayed during 2012 was to be done during 2013. PG&E thus argues that if the 2012 forecast is reduced based on actual spending, the 2013 forecast should be increased to $18.8 million to make up the difference.

TURN challenged PG&E's estimate for the gas control/dispatch center on the basis that PG&E's estimate of $605 per square foot of capital and expense of $63.25 per square foot of expense exceeds PG&E's estimate of $560 per square foot for new office building construction. TURN claims that the Control Center project is more in the nature of tenant improvements to an existing facility. PG&E presented a forecast cost of tenant improvements in its workpapers with a unit cost of $125 per square foot, which is substantially below that of new office construction ($560 per square foot). TURN claims PG&E did not sufficiently demonstrate where figures come from, or why they are reasonable. TURN also proposes a reduction of $7.2 million to remove a 15% contingency allowance,

PG&E responds that this is no ordinary building project, but requires complex SCADA equipment to monitor and control the 42,000 mile, million service distribution system.

Discussion

All parties agree that the Control Center will serve an important safety function, and should be funded. We first address the dispute over project timing as it relates to the forecast amount by year. Since PG&E spent less than for forecast during 2012, we adopt actual 2012 spending as the forecast amount for 2012. PG&E and DRA both agree on the 2013 capital forecast, and we adopt this uncontested amount for 2013. We agree with PG&E that since there was a delay

in spending in 2012, an adjustment should be made to add the remaining amount of the unspent forecast applicable to subsequent years. As previously discussed in connection with approval of control center remote monitoring devices, however, we believe that PG&E's expectation of completing the Control Center by 2014 is overly ambitious.

We next address the dispute over common cost allocations. PG&E opposes TURN's allocating only 27% of common costs to the distribution function. PG&E argues that it's forecast for the Control Center already excludes costs associated with the transmission control center, and that the entire remaining forecast is only for the Distribution Control function. We interpret PG&E's statement to mean that its forecast includes only the distribution function after applying its own allocation methodology. We believe that a 40% allocation for common costs should apply, consistent with the approach applied to the headquarters building. In applying this allocation, we take into account the amounts that PG&E has already excluded for the transmission portion of costs. We also apply the 40% common cost allocation to adjust PG&E's 2014 expense forecast for the Control Center.

We recognize that the control center is more involved than an ordinary building project, and more than mere tenant improvements. We are unconvinced, however, that costs as high as $605 per square foot for the Control Center are justified. As noted by TURN, the capital cost of $605 per square foot of capital cost and expense of $63.25 per square foot exceeds even PG&E's estimate of $560 per square foot for construction of a new office building. The Control Center here does not involve construction of a new building, but is more in the nature of tenant improvements to an existing facility. We reduce PG&E's capital cost forecast for the Control Center from $605 to $560 per square foot

figure, which represents PG&E's estimate for the construction of a new office building.

We also reduce PG&E's forecast by $7.2 million for a contingency allowance, as proposed by TURN. PG&E identifies nothing particularly unusual or complex about cost estimations for the Gas Training Center that would justify the need for ratepayers to cover a contingency amount of $7.2 million.

Given the above discussion, we adopt the following forecast for the new gas control dispatch building as follows: $2.324 million for 2012 and 2.819 million for 2013.

3.12.3. Gas Control Hot Backup Facility

PG&E proposes to create a mirror-image "hot" backup to its new gas control and dispatch center, and forecasts $3.337 million in 2014 capital expenditures for MWC 78 for this purpose.[30] PG&E explains that the backup facility will allow for uninterrupted, efficient shift of gas control and dispatch functions to the backup location in the event of an emergency that disrupts or prevents use of the primary control center.

TURN claims that PG&E presents no analysis demonstrating that the safety and reliability benefits of this planned redundancy justifies the $30 million dollar-plus price tag, or that there was no less expensive back-up strategy worthy of consideration. PG&E acknowledges a "temporary gas distribution control

[30] PG&E uses the term "hot" backup to describe a facility with the duplicative operational ability of a primary location that is in a state of stand-by to be activated in the event of an emergency.

center hot backup" is located in its Brentwood facility alongside the hot backup control center for PG&E's transmission system.

This project is not expected to go into service until after the 2014 test year. TURN also questions why PG&E included in its showing cost forecasts associated with such post-2014 projects. TURN proposes the Commission decline to expand the scope of review to specific projects unlikely to go into service until after the 2014 test year.

TURN argues that because the hot back up control center is expected to be operational prior to the 2017 rate case period, the current GRC is not the appropriate vehicle to address the reasonableness of the project.

PG&E responds that the temporary facility is not an adequate substitute as it has none of the distribution control functionality that PG&E needs and which Cycla found consistent with industry best practices.

Discussion

We conclude that given the time frame involved in its planned completion, it is premature to address the issue of PG&E's proposed funding for the hot backup center in this decision. Accordingly, we exclude from PG&E's 2014 capital forecast for MWC 78 the $3.337 million in proposed funding for the hot backup center. Cycla suggests that PG&E may wish to consider stretching the time for construction and implementation of the "hot" back-up control center dispatch facility, especially considering the complexities associated with making the new control center fully operational. At the time of the 2017 GRC, we expect PG&E to provide an update on the status of its plans for the hot backup control center, with a more specific schedule for proposed implementation.

3.12.4. Gas Training Center

For the 81% distibution portion of PG&E's costs, PG&E proposes to spend $6.1 million in capital and $1.05 million in expense on a new 30-acre gas training facility near Winters. PG&E forecasts $32.962 million in capital expenditures in 2014 for this facility to provide technical training to maintenance, construction, operations and engineering employees in areas such as carbon monoxide and leak investigation and repair techniques and to facilitate training employees on new technologies.

DRA recommends no funding for the training center, arguing that: (1) PG&E does not need a new facility to train employees in a manner consistent with industry best practices; (2) "emergency response exercises would be more practical to be planned and organized with first responders in locations throughout PG&E's service territory that may be unique to that location rather than at a new gas training center location many miles away"; and (3) "new Transmission Training facilities can be requested in proceedings outside of this GRC."

PG&E conducted a benchmark study in 2011-12 to compare its gas training to best-in-class, identify gaps, and put together an extensive plan to elevate all PG&E gas training to best-in-class. The benchmarking led PG&E to conclude that its existing facilities were inadequate and that a new training facility was needed.

The training center would cover issues for distribution service i.e., measurement and control, field services, construction techniques, emergency response). Thus, the ability to seek costs for a transmission training facility outside of the GRC is not applicable.

TURN recommends reducing PG&E's capital expenditure forecast for the training center by $8.427 million (for 2013) and $36.952 million (for 2014).

TURN recommends reducing PG&E's expense forecast for the training center by $586,000. The reductions are based on (1) a cost of $240 per square foot, rather than the $676 per square foot PG&E forecast, (2) allocating only 27% of costs to distribution and (3) eliminating a 15% contingency factor.

TURN challenged PG&E's estimate of unit costs. PG&E estimated unit costs of more than $676 per square foot to build this facility, plus a15% contingency factor (or $7.2 million). TURN developed an alternative forecast new construction unit cost of $240 per square foot, and eliminated the contingency based on the Commission's past practice of removing such amounts for "rough order of magnitude" estimates.

PG&E disputes TURN's unit cost challenge, arguing that the $240 per square foot figure TURN used was based only on national average cost for a new medical building, not for a natural gas training facility. TURN responds that it did not use the $240 per square foot figure because PG&E's project is similar to a medical building. Rather, TURN used the highest available non-PG&E unit cost data for new construction, which turned out to be the national average for a new medical building.

TURN claims that PG&E failed to demonstrate the reasonableness of its forecast for this project. PG&E worked with "Swinerton Builders to compile a Rough-Order-of-Magnitude (ROM) estimate for the costs." The "detailed cost estimate" provides no information that would establish the reasonableness of the cost estimates. TURN recommends removing the "project contingency" cost of $7.2 million, and using lower unit cost estimates based on TURN's forecast of $21.1 million.

Discussion

We conclude that funding for the new training center is warranted. DRA acknowledged that neither web-based nor instructor-based training are adequate substitutes for live simulation training. DRA did no study to determine whether PG&E's existing facilities are adequate for live simulation training for any of the activities listed above. DRA agrees that these are important training activities.

We reduce PG&E's forecast amount, however, (1) to remove PG&E's project contingency of $7.2 million and (2) to reflect allocation of the building costs to gas distribution based on the 40% allocation of gas distribution employees, as used for the Gas Control Center, discussed above. Given the level of costs involved, we find insufficient basis to burden ratepayers further with an additional contingency fee. The approved funding offers enough money to cover unforeseen contingencies.

We also find that PG&E's forecast cost per square foot appears excessive in view of the lack of detailed cost support and in comparison to other available benchmarks. TURN's alternative forecast based on the national average for a new medical building, however, is not precise enough as a basis for setting a revenue requirement. The national average for a medical building does not reflect geographic differences in construction costs, or the specialized mechanical and electrical infrastructure needed for the Control Center. To resolve differences over parties' conflicting estimates, we limit PG&E's forecast cost for the training center to the $485 per square foot cost that PG&E has estimated for the Antioch Service Center which PG&E developed for a generic 53,000 square foot office construction project. This amount is less than what PG&E forecasts for the Control Center, but is still based on PG&E-specific cost data.

3.12.5. Antioch and San Carlos Service Centers and Vaca Dixon Yards

PG&E forecasts 2014 expense of $565,000, $185,000, and $81,000 for funding the Antioch, San Carlos, and Vaca Dixon Service Centers, respectively. TURN disputes PG&E's forecast for the Antioch Service Center.

The Antioch Service Center project is to replace temporary office space installed in 1979 with a permanent structure of 15,000 square feet and a 2-acre paved yard to accommodate growth and provide a safer employee environment. PG&E forecasts $6.75 million for construction, $958,320 for paving capital costs, and $780,000 of related expense. PG&E claims that current facilities need to be replaced because they are losing their integrity and structural soundness.

TURN recommends rejecting the Antioch project, arguing that no new service center is needed. Assuming the Commission authorizes funding, however, TURN presents an alternative forecast of $3.1 million in capital and $284,000 in expense. PG&E relies on an office construction unit cost of $485 per square foot developed for a generic 53,000 square foot office construction project, adjusted to $450. TURN claims that PG&E's use of $11 per square foot for paving costs is double the unit cost PG&E itself developed for such costs, according to the Corporate Real Estate workpapers. The adjustment from $11 to $5.49 per square foot would reduce the forecast by more than $475,000.

PG&E explains that its workpapers provide two unit costs: (1) $15 for new paving and (2) $5.49 for re-paving. This is a new paving project. PG&E's $11 per square foot forecast is thus lower than the $15 workpaper figure.

DRA recommends reducing PG&E's forecast by $300,000, arguing that these are one-time expenses. DRA proposes a lower capital expenditure forecast for the Vaca Dixon and San Carolos Service Centers.

Discussion

We recognize that the Antioch Service Center represents aging infrastructure that will need to be addressed in due course. Given the significant magnitude of other higher-priority expenditures being undertaken during the 2014-16 GRC cycle, however, we conclude that ratepayers should not be burdened with this additional project expenditure for this GRC cycle. PG&E should manage with the current facility for now, but may renew its request for funding a new facility in the next GRC.

3.12.6. Vaca Dixon Yard

PG&E proposes funding to replace temporary office space at the Vaca Dixon Substation used by gas general construction employees. PG&E forecasts capital expenditures of $81, 000 in 2012 and $3.427 million in 2013. DRA recommends funding of $107,000 for 2012 and only $200,000 in 2013 based on changes in the scope of the project after PG&E submitted its forecast. PG&E does not deny that its overall forecast cost for the Vaca Dixon project declined based on changes in project scope, but opposes DRA's proposed reductions unless corresponding increases are made to other 2013 and 2014 forecasts that turned out to be higher than originally forecast.

Given the fact that PG&E changed the scope of the project after its forecast was made, we agree with DRA that authorized funding should be reduced accordingly. Unlike other projects where temporary delays in 2012 were not expected to change the forecast of ultimate funding needed during the 2014 test year, PG&E has not shown that the original overall funding for this project remains accurate. Accordingly, we adopt a reduced forecast cost to reflect DRA's recommended reductions for the Vaca Dixon Yard.

3.12.7. Miscellaneous Building Projects Under $1 Million

PG&E forecasts capital expenditures for 2012, 2013, and 2014, of $3 million, $3.485 million, and $2 million, respectively, for 25 miscellaneous building projects, each of which is valued at under $1 million. DRA recommends reducing these forecasts to $24,000, $250,000, and $250,000, based on using 2012 actual expenditures for 2012 forecasts, and using 50% of PG&E's 2011 capital expenditures of $496,000 recorded in MWC 78 as the basis to forecast minor projects for 2013 and 2014 since PG&E does not have 2007-2012 data for MWC 78 projects broken down for major and minor projects.

DRA does not identify any factors that warrant a conclusion that any of the forecast minor project costs are unreasonable. We conclude that PG&E's forecast for minor projects under $1 million are reasonable and approve its forecast for 2012-2014.

3.12.7.1. Publicly Available Specification (PAS) 55 Certification

PAS 55 is the British Standards Institute's publicly available specification for optimized management of physical assets and requires evidence of alignment between good intentions and actual delivery. It is a valuable mechanism to ensure that life cycle planning, risk management, cost/benefit analysis, customer focus and sustainability are actually delivered. PG&E forecasts $500,000 in expense for initial certification and will incur expense for ongoing certification requirements.

DRA recommends normalizing the 2014 cost over the rate case cycle, reducing PG&E's forecast to $167,000, treating this as a one-time cost. PG&E explains that PAS 55 certification is not a one-time cost. The initial certification will occur in 2014, but there are on-going costs to maintain the certification. We

conclude that PG&E's 2014 forecast is reasonable for PAS 55 Certification and hereby adopt it.

3.12.7.2. AGA Fees

PG&E forecasts $300,000 for AGA fees for membership and access to best practices benchmarking information. DRA recommends reducing this forecast to $243,000 on the assumption that a portion of this money is for lobbying. PG&E claims its forecast does not include funds for lobbying, but is based on prior AGA invoices, allocated evenly between gas distribution and gas transmission, and then allocated 25% to lobbying, based on historical experience, which is then excluded from its forecast. Since PG&E's forecast already excludes lobbying costs, we find that PG&E's forecast for ratemaking recovery of AGA fees is reasonable and hereby adopt it.

4. Electric Distribution

4.1. Policy and Introduction

The electric distribution revenue requirement covers costs for PG&E to: (1) own, operate and maintain (a) distribution plant; (b) a portion of transmission plant providing service directly to specific customers and connecting to specific generation resources; and (c) a portion of common and general plant; as well as to provide services to its 5.4 million electric distribution customers.

4.2. Electric Operations Technology

4.2.1. Introduction

PG&E forecasts for Electric Operations Technology Projects for Distribution System Operations, Asset and Records Management, Work Design and Management, and Workforce Mobilization and Scheduling. Electric Operations Technology covers 17 projects in four technology areas as shown in Tables 4-4 (Expense) and 4-5 (Capital) of PG&E's Brief.

PG&E forecasts capital expenditures for 2012-14 of $37.89 million, $53.499 million, and $70.67 million, respectively for MWC 2F, Electric Operations Technology and $12.07 million in 2014 expense in MWC JV to enhance technology applications and deploy new technologies. We resolve disputes and adopt forecasts regarding Electric Operations Technology projects, as discussed below.

4.2.2. Electric Distribution Geographic Information System/Asset Management (GIS/AM)

For its Electric Distribution GIS/AM project, PG&E forecasts capital costs in MWC 2F of $20.6 million for 2012, $32.2 million in 2013, $27.8 million in 2014, $2.0 million in 2015 and $2.0 million in 2016. PG&E also forecasts $1.8 million in 2014 expenses. This project funds PG&E's efforts to validate, enhance, and convert legacy mapping and asset connectivity data to a single GIS to maintain geospatial and other attributes of assets.

DRA proposes no funding for this project arguing that PG&E forecasted the same project in the last GRC, and customers shouldn't fund this project twice. PG&E denies that the current project is the same one that was previously forecast.

In support of a proposed disallowance for the GIS/AM project, DRA also relies on D.12-12-030 (Pipeline Safety Enhancement Plan (PSEP)), which disallowed recovery of PG&E's gas transmission Pipeline Records Integration Program.

TURN also opposes project funding approval. If any funding is approved, however, TURN proposes that such funding exclude the 18% provision for unforeseen contingencies. TURN also proposes that PG&E be required to produce a full benefit/cost analysis after project completion. TURN proposes

that expenditures for the ED-GIS project, together with components of the Workforce Mobilization Project, be combined into a memorandum account capped at authorized funding levels.

Key mapping and asset management projects PG&E has undertaken as part of its evolution over the past several years were described to DRA in responses to data requests.

PG&E claims that DRA's recommendation to reject the ED GIS/AM would result in abandoning investments for technology that has not been fully implemented but included in forecasts in PG&E's 2011 GRC and expected as part of PG&E's project plan.

TURN proposes that funding for Electric Distribution (ED)-GIS (Electric and Gas) and Workforce Mobilization and Scheduling (Electric and Gas) be limited to $192 million in 2012-2016. Specifically, for ED-GIS (Electric and Gas) TURN proposes $107.7 million; and for Workforce Mobilization and Scheduling (Electric and Gas) $100 million in IT spend less the following amounts: $2 million for PG&E's lower request for mobile units; $2 million for TURN's proposed reduction in mobile units for service planners; $5.5 in IT spend for the reduction to mobile devices for additional electric crew members; and $6.25 million in IT spend for TURN's proposed reduction to the Scheduling Integration with Time Management project.

Discussion

We approve PG&E's forecast for the ED GIS/AM project for 2012-2016, but with a reduction of approximately 25% to remove the provision for contingency fees and to account for the lack of cost/benefit analysis. Specifically, for the expenses in MWC JV, we approve $1.373, a reduction of $458,000. For the capital expenses in MWC 2F, we approve $15.45M for 2012, $24.1M for 2013, $20.9M for

2014, $1.5M for 2015, and $1.5 for 2016. In addition, given the other large funding increases at issue in this GRC, we conclude that burdening ratepayers with full funding of this project has not been sufficiently justified.

We recognize that PG&E performed no structured risk assessment or cost/benefit analysis to support its funding proposal for this project. Nonetheless, based on our own assessment of project benefits, we conclude that the GIS/AM platform warrants funding in view of the improvements it will provide. The ED GIS/AM project will benefit ratepayers by bringing PG&E's mapping and asset management into line with best industry practices. PG&E is now lagging the industry in transitioning from manual to electronic mapping and asset management. The lack of a functional registry system was a major finding in the IRP Report. Liberty also considers PG&E's current legacy mapping system to be dysfunctional.

The GIS/AM project will be integrated with PG&E's enterprise asset and work management system as a unified records and asset management system with a streamlined user interface to perform data entry, analysis, and dynamically maintain and update essential records. Most technology initiatives within the Electric Distribution Technology Project Portfolio will leverage the GIS/AM platform to improve operating efficiency and accuracy.

We conclude that our disallowance of PG&E's gas transmission Pipeline Records Integration Program costs in D.12-12-030 does not provide a basis for denying funding for prospective improvements for the ED GIS/AM project. In D.12-12-030, we did not address electric distribution facilities or related recordkeeping requirements at issue here. Recordkeeping expectations for gas transmission involve different considerations from the requirements for electric

distribution. Therefore, it is inappropriate to apply the findings in D.12-12-030 to the ED GIS/AM project.

We conclude that the current project bears some similarities to the previous project forecasted in the 2011 GRC, but there are also differences. The strategy and scope of the currently proposed ED GIS/AM project is to integrate critical utility business information systems and eliminate paper-based asset and records management practices, and does not include remedial work to correct past deficiencies. The previous forecast in the 2011 GRC was for a combined gas and electric Asset Mapping/Facilities Management project with basic GIS capabilities. PG&E subsequently completed only certain tasks associated with that project, closed that program in 2011, and moved remaining tasks into separate gas and electric projects. Consequently, because that prior project remained uncompleted, the funding previously authorized for that combined gas and electric project may have exceeded, at least to some extent, the amounts actually spent on the project.

We thus conclude that ratepayers have already born some risks of funding the prior GIS project forecasted in the 2011 GRC without receiving any benefits from completion of the originally anticipated project. Consequently, ratepayers should not be burdened with funding further unanticipated contingencies associated with the GIS/AM platform that is now being proposed. We recognize that PG&E may encounter different conditions when this project is implemented (over a two and a half year period) than were known when the forecast was first developed. We conclude, however, that given the levels of funding we approve, PG&E should absorb any further risk of unforeseen contingencies. We decline, however, to adopt TURN's proposal that spending for the ED GIS/AM program be capped and subject to memorandum account treatment. Consistent

with forward-looking test year ratemaking principles, we decline to rely on hindsight review for this project. We believe that PG&E should have the flexibility to adjust spending for this program as changing conditions warrant over time without being subject to memorandum account caps. By the same token, we acknowledge TURN's concerns about PG&E's lack of a full benefit/cost analysis but don't believe it is appropriate to require such after project completion. Thus, to account for the lack of benefit and cost analysis, in addition to removing the contingency costs for the project, we find it appropriate to reduce the capital expenditures forecast for 2012-2016 by 25%.

4.2.3. Workforce Mobilization and Scheduling Projects

PG&E seeks funding for Electric Distribution Workforce Mobilization and Scheduling Technology (Workforce Mobilization) projects, with capital funding in MWC 2F for 2012 based on recorded costs of $7.2 million, and forecasts for 2013 of $11.1 million, and $14.8 million in 2014. For 2015 and 2016, PG&E forecasts capital funding of $27.0 million and $28.6 million, respectively. PG&E forecasts $2.97 million in 2014 expenses for Workforce Mobilization in MWC JV. (PG&E's Opening Brief at 4-23.)

Workforce Mobilization projects consist of: (1) field crew/work type projects; (2) work scheduling and dispatch system consolidation; and (3) scheduling integration with time keeping systems. PG&E claims these initiatives will yield more efficient scheduling and dispatching, improve records accuracy, and reduce administrative work. PG&E's dispatchers can notify field crews and provide work instructions during emergencies when crews are already in the field and can automatically assign them to the highest priority

work. Mobile technology will improve coordination with local emergency response teams during emergency and outage situations.

Liberty did not classify the workforce mobilization project as a safety initiative, but mainly as targeting work efficiency improvements.

DRA recommends no funding of expense or capital for the Workforce Mobilization projects, stating that the projects are an inefficient use of ratepayer funds and that the capital revenue requirement (2010-2016) exceeds forecast annual savings. DRA notes that the $77.5 million in capital expenditures from 2010 through 2016 generates annual costs of $11.6 million. DRA's analysis relied on the low-end estimate.

TURN recommends several reductions under the Workforce Mobilization and Scheduling Category. For expenses, TURN recommends disallowing $110,000 in 2014 for Mobile for Additional Crew Members and $450,000 in 2015 for Scheduling Integration with Time Management project. For capital expenditures, TURN recommends disallowances in three projects. For the Mobile Devices for Additional Crew project, TURN recommends disallowing $1.76 million in capital in each of 2014, 2015, and 2016. TURN also recommends zero funding for the Scheduling Integration with Time Management project, a reduction of $1.75 million of PG&E's forecasted capital expenditures in each of 2015 and 2016. For the Service Planners project, TURN recommends a 20% reduction as belt-tightening, should the Commission address post-test year projects, reducing capital expenditures by $1.3 million in 2015 and $758,000 in 2016. Additionally, as noted above, TURN proposes that PG&E be required to

provide a cost/benefit study for the Workforce Mobilization projects through a memorandum account.[31]

Discussion

We approve funding for Workforce Mobilization and Scheduling Projects, consisting of expenses forecast in MWC JV and capital forecasts in MWC 2F, but with slight modifications to incorporate some of the reductions proposed by TURN. We thus reduce the capital forecast by $1.317 million for 2014, $4.343 million for 2015, and $3.835 million for 2016. We reduce 2014 expense by $110,000. We adopt PG&E's 2012 recorded spending level of $7.2 million as the approved 2012 funding level for MWC 2F.[32]

We find that the Workforce Mobilization projects offer certain prospects for cost savings and for qualitative benefits. PG&E has estimated savings from Workforce Mobilization projects range between $8.4 million to $11.6 million in 2015 and beyond, and $6.4 million savings for 2014. The high-end of the estimated range of savings equals DRA's estimate of $11.6 million for annual project costs. In addition to the potential for cost savings, there are qualitative benefits to improve public and employee safety, reliability, compliance documentation, and customer satisfaction. While we conclude that funding is warranted in view of the qualitative improvements and potential savings, we acknowledge TURN's concerns that PG&E's proposed spending levels appear excessive in relation to potential benefits. We thus conclude that the some of the

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[31] TURN's Opening Brief at 86 (expense) and at 100-104 (capital).

[32] PG&E's Opening Brief at 4-23.

reductions proposed by TURN in PG&E's forecasts are appropriate, and adopt those reductions. The reductions are discussed in more detail below.

PG&E factored the estimated savings generated by the workforce mobilization projects into its cost escalation offset. In order to achieve cost savings forecast in this rate case, PG&E claims it needs the funding to implement them. We discuss the various elements of PG&E's Workforce Mobilization below. We discuss the treatment of PG&E's proposed productivity to offset in Section 4.20.2.

PG&E committed to offset Electric Distribution escalation for 2012-2015 via productivity improvements and other initiatives as a result of its Electric Operations Improvement Plan (EOIP). This totals roughly $30 million in expense for 2014-2016 and $180 million in capital from 2012-2015. No capital escalation offset was calculated for 2016 according to PG&E's methodology.

PG&E calculates a productivity benefit for Electric Distribution as 1.7% of the 2014 expense request and 2.5% of the 2014 capital request. TURN argues that PG&E's claim that the escalation is representative of the productivity benefit is merely an assumption, and that efficiency benefits could potentially exceed the escalation in expense and capital. Actual capital savings for 2012 from the improvement program have been higher than forecast, although expense savings were less than forecast.

TURN claims that efficiency improvements are not necessarily due to IT investments, and that the majority of predicted capital savings from the EOIP are from analysis of shared costs and overheads and from reviewing labor and contracting strategies. In rebuttal, PG&E claims that obtaining efficiencies do require the IT expenditures requested, because the efficiency improvements are "data-driven."

TURN argues that significant savings are possible with existing data or additional research of opportunities. For example, part of PG&E's solution strategy is to focus on the highest cost programs (e.g., Emergency Response, Maintenance, New Business/Work at the Request of Others (NB/WRO)) that will provide $26 million in savings in 2012. Another major opportunity is saving materials costs by examining sourcing opportunities ($82 million in savings). TURN argues that the largest savings do not require or warrant $350 million in additional IT spend between 2012-2016. TURN claims that the forecast costs for IT expenditures in Electric Distribution are greater than the benefits PG&E is claiming, and that PG&E needs to achieve greater benefits or lower costs to align its IT expenditures.

Workforce Mobilization by Field Crew or Work Type - Mobile for Service Planners

PG&E's service planners currently collect service information on paper, perform certain tasks in the office and then contact the customer with that information. The proposed project will enable data gathering and initial contract arrangements to be made in the field on the first visit. Regarding Workforce mobilization for service planners, PG&E requests $10.2 million in IT for 2015-2016.[33] This funding provides for purchases of 948 units, which includes an allowance for spare devices of 15%. (Ex. 123 at 31.) PG&E explains that these devices are purchased to replace units in the field if they malfunction, are damaged, stolen or lost or are given to new employees. The mobile devices are

[33] PG&E-4 at 2-52.

to meet specific workgroup needs and require six to eight weeks lead time to manufacture, thus requiring their advance purchase.

We adopt TURN's recommendation for a 20% reduction as a belt-tightening adjustment. This reduces the capital expenditures by $1.274 million in 2015 and $769,000 in 2016. PG&E has not determined if mobile devices will replace desktop computers. TURN also refers to "15% extra laptops in case one is non-operational."

Mobile Devices for Additional Crew Members

PG&E seeks capital funding of $1.317 million in 2014, $1.321 million in 2015, and $1.317 million in 2016 and $110,000 in 2014 expense to acquire mobile devices for additional crew members to enhance productivity and improve emergency and outage response time. TURN proposes no new funding for these mobile devices, stating that PG&E has not sufficiently demonstrated the efficiencies.

TURN also claims the project will cause data quality issues. PG&E claims that it explained in a data response how data quality is assured through several steps as summarized in Exh. PG&E-19 at 2-36.

PG&E requests funding for 532 mobile devices for 445 electric T200 and T300 crews. This covers one device per crew, with 20% spare. For PG&E's 300 gas long and short cycle plus general construction crews, PG&E requests 346 mobile devices, equivalent to one per crew plus 15% spare. TURN considers one mobile unit per crew plus spares to be adequate at this time, as mobile technology is changing rapidly.

PG&E argues, however, that by providing crews with an additional mobile device, crews can split into teams for smaller jobs and both teams can receive and complete work packages in the field, resulting in greater efficiencies. The project

supports capturing overtime, travel time and crew sizing efficiencies initiatives described in the Improvement Plan.

Given that the average crew size includes only 4.36 workers, the proportion of crews that are as large as six is relatively small. We agree with TURN that the 15-20% spare units should serve as a sufficient cushion to cover the eventuality that a large crew needs to split. Therefore, we disallow funding for this project.

Scheduling Integration with Time Reporting

PG&E claims this project enhances and automates the exchange of time reporting among different systems and allows field employees to electronically capture and transmit time keeping data. TURN opposes funding, stating that the project is not justified, and only saves clerical time. PG&E explained that it will also reduce supervisor review time, improve quality of payroll data, better unit cost data, and improve recordkeeping. We agree with TURN that the potential savings and improvements claimed due to the scheduling integration project are not sufficient to justify the costs. We thus disallow capital of $1.75 million for 2015 and 2016. TURN also recommends to disallow 2015 expense of $0.45 million, but PG&E has not requested such expense.

As-Built Drawings

The Workforce Mobilization projects would enable the workforce to review as-built drawings on mobile devices. TURN questions the value of this benefit compared to the cost. We are persuaded that the benefits justify the costs. PG&E argues that field conditions can be difficult for employees to interpret without access to as-built drawings. Due to visual obstructions or construction methods (e.g., underground facilities), employees cannot see key aspects of the

facilities necessary to perform their work. Field access to as-built information will improve the safety, reliability and efficiency of PG&E's field activities.

4.2.4. Data Historian for Electric Distribution

PG&E forecasts capital costs of $12.3 million in 2014, $10.9 million in 2015, and $1.0 million in 2016, and $0.2 million in 2014 expenses for its Data Historian project.

PG&E's data historian software application provides central data archiving and analysis generated by PG&E's SCADA system. The project will replace existing software with an upgraded, industry standard data historian application to enable engineering and planning functions with more granular data and more powerful analytical tools. The Data Historian project is intended to develop advanced system alarms to monitor new types of data and identify trends through more advanced analysis to provide early warning of potential equipment failures and unstable operating conditions.

DRA and TURN both oppose funding for the Data Historian project, arguing that PG&E failed to show that ratepayer benefits justify the costs. TURN argues that PG&E failed to show that the additional functionality from the Data Historian project is worth $25 million over three years. Both PG&E and Liberty call this as a safety project, but PG&E classified it as only "medium" priority. PG&E presented no analysis of whether outages would be avoided or quantitative impacts. TURN also opposes forecast amounts beyond the test year (i.e., $10.9 million in 2015, and $0.98 million in 2016).

PG&E claims the existing system cannot accommodate *planned* increases in SCADA devices. TURN, however, recommended a reduction to PG&E's SCADA request. PG&E admitted that its existing Data Historian system could accommodate a small expansion in the number of SCADA devices.

Discussion

We conclude that the Data Historian Project is justified, but with a reduction of 25%, as we believe this will sufficiently allow PG&E to move forward with this project and will be in line with our approximately 25% reduction for Installation of Substation SCADA (*see* Section 4.17). For expenses in MWC JV, we approve $155,000, a reduction of $52,000. For the capital expenses in MWC 2F, we reduce capital expenditures by $3.1M in 2014. We express no opinion on 2015-2016 forecasts. Given the other large funding increases at issue in this GRC, we conclude that burdening ratepayers with full funding of this project has not been sufficiently justified.

The Data Historian project, implemented in conjunction with increased SCADA capabilities, will provide system safety and reliability benefits by helping reduce equipment failure, fire risk and outage durations through enhanced monitoring, analysis and control. PG&E's knowledge of asset conditions will be enhanced so that equipment can be repaired in advance of failure.

PG&E's existing Data Historian system cannot support modern grid operational needs nor accommodate planned increases in SCADA devices such as circuit breakers, reclosers and switches. The existing tool has limited integrated analysis screens that require manually intensive analysis. Liberty agrees that PG&E's data historian capabilities currently lag the industry and need to be upgraded to keep up with the increased SCADA functionality.[34]

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[34] Liberty Report at 119.

We thus, conclude that these safety and reliability benefits to customers justify the data Historian project, and approve PG&E's forecast for 2014, but with a reduction of 25%. We express no opinion on 2015 and 2016 forecasts. Attrition for 2015 and 2016 is separately addressed in Sec. 12.

4.2.5. Customer Connection Online (CCO)

PG&E forecasts $3.9 million in 2014 expense, incurred actual capital costs of $2.8 million in 2012, and forecasts $11.1 million in capital for 2013-2016 for the CCO project. This initiative builds upon SAP Work Management (Plant Maintenance Module) enhancements to provide improved work order management and tracking.

DRA recommends funding only a 2014 forecast of $1.949 million, reflecting a 50% reduction in PG&E's forecast for the CCO project. DRA argues that claimed customer benefits do not justify funding the level of CCO project costs that PG&E seeks. DRA considers development, implementation and testing costs to be one-time non-recurring costs such that additional funding is not required during the rate case cycle for this activity. DRA argues that ratepayers should not provide funding for recurring costs already embedded in historical expenses. DRA claims that PG&E has not demonstrated that the funding authorized in its 2011 GRC associated with its Distribution Control Centers (DCC) consolidation project is insufficient.

Since this project serves NB activities (i.e., hooking up new customers to PG&E's system or adding additional facilities for existing customers), TURN proposes that those customers causing this expenditure pay for it. Similar to the principle behind collection of new customer connection administrative costs, TURN proposes that this project be paid for by a new online administrative fee. PG&E opposes TURN's proposed administrative fee, arguing that its customers

access all kinds of products and services from other vendors and service providers via online services. PG&E claims it is virtually unheard of to charge customers to obtain services online.

Discussion

We approve PG&E's forecast for this project. But, for the 2012 capital expenditures in MWC 2F, we approve the recorded CCO program expenditures of $2.792 million instead. We recognize that PG&E's existing online tools are cumbersome and do not adequately meet customer needs for requesting and monitoring service requests. The new CCO tools offer enhanced website capabilities and better integration to back end systems to provide customers timely and direct access to service request status and related information. We find that the CCO project provides customers with added transparency regarding project timelines, work status, updates and alerts when milestones are met. Customers will have 24/7 online access to project information, reducing project status calls to the PG&E Contact Center and providing customers more convenience.

PG&E identified $0.8 million in cost savings per year starting in 2013 for Phase 1, and anticipates additional financial savings for Phase 2 of the CCO project. PG&E relies on such cost savings to offset its forecast of cost escalation, but did not specifically attribute savings to the CCO project.

We decline to adopt DRA's proposed 50% disallowance. Applying a 50% reduction, the forecast for the CCO program would be $416,000 for 2013 and $1.916 million for 2014. It is unclear how this reduced level of funding could affect PG&E's ability to implement the proposed CCO project and related improvements. We find insufficient rationale to reduce the adopted forecast. For purposes of this decision, we do not adopt TURN's proposal that cost

recovery for this project be limited to charging the users of the website via "a new online administrative fee." TURN argues that because this project involves hooking up new customers to PG&E's system or adding additional facilities for existing customers, the project should be paid for only by the customers causing this expenditure. PG&E objects, claiming that customers access all kinds of products and services from other vendors and service providers via online services, and charging website users to obtain services online is virtually unheard of. Considering the unprecedented nature of TURN's proposal in comparison to customary practices for on-line services, we decline to impose a separate fee on customers' use of this on-line service.

4.2.6. Outage Reporting and Analysis System Replacement

PG&E forecasts capital costs of $3.3 million in 2013, $4.5 million in 2014, and $0.4 million in 2014 expenses for its Outage Reporting and Analysis System Replacement project. This project moves outage reporting out of PG&E's existing Centralized Electric Distribution System Analysis (CEDSA) system and into another platform based on the GIS/AM project.

PG&E claims the new platform will increase outage reporting and tracking efficiency, improve data capture accuracy, and reduce duplicate data entry processes, and increase accuracy in outage reporting. The Outage Reporting and Analysis System Replacement project will be completed along with the ED GIS/AM project. PG&E did not estimate cost savings for this project, nor the costs of alternatives.

DRA proposes reducing funding for this program by 14% due to its concerns with the Concept Cost Estimating Tool. TURN recommends no

funding for the project claiming that: (1) the ED GIS/AM project is delayed; and (2) PG&E's existing CEDSA system can meet outage reporting requirements.

Discussion

We conclude that the Outage Reporting and Analysis System Replacement project is justified, but with a reduction of funding. We adopt DRA's recommendations regarding forecasts based on the Concept Cost Estimating Tool, as discussed in Section 7.8.2, which reduces PG&E's forecast funding by 14%. Therefore, we approve $311,000 for expenses and $2.8M for 2013 capital expenses, and $3.9M for 2014 capital expenses. Liberty acknowledged that PG&E's current outage reporting system cannot track conductor failures by wire size, but could not say whether it is worth $8 million to obtain this information. Yet Liberty did find that the existing tools are hindering PG&E's system safety improvement and recognized the critical nature of this project by classifying it as a safety initiative.

We therefore conclude that ratepayer funding of this project is necessary in order for PG&E to retain the ability to report on its reliability performance or to perform analyses necessary to meet customer expectations for service reliability. Continued use of CEDSA is not feasible for this purpose because CEDSA will be retired as part of the GIS/AM project by the end of 2014.

4.2.7. Graphic Work Design Tools

PG&E forecasts capital costs of $3.0 million in 2013, $3.1 million in 2014, $3.1 million in 2015, and $0.3 million in 2016, and $0.8 million in 2014 expenses for its Graphic Work Design Tools project. PG&E proposes replacing its current construction design and estimating toolset with more modern, integrated and graphics-based construction visualization and estimation software. DRA agrees that modern design tools will provide improvements as PG&E claims and save

ratepayers money over time, but proposes a 14% reduction relating to use of the Concept Estimating Tool as discussed at Section 7.8.2.

TURN proposes disallowance of $2.9 million in 2013, $3 million in each of 2014 and 2015, and $0.3 million in 2016. TURN argues that PG&E has not shown the urgency of this project or that the benefits of integrating the existing system into one elegant tool are worth a $12.4 million addition to rate base. TURN recommends no funding based on assumed timing of the project relative to completion of the GIS/AM project. TURN claims that PG&E can rely on existing design tools. TURN claims there are no quantified benefits, but the project is intended to achieve more customer satisfaction, increased data integrity regarding distribution assets, and employee productivity by streamlining documents and estimates.

PG&E explains that proposed enhancements to its current design tool are only to keep the existing system running until conversion to the new graphic work design tools. The existing tool will not support integration with the ED GIS/AM system.

Discussion

We approve funding for PG&E's proposal for Graphic Work Design Tools as reasonable, but also adopt DRA's proposal, to reduce PG&E's forecast to reflect the 14% disallowance relating to use of the Concept Cost Estimating Tool as discussed at Section 7.8.2. The proposed tools can significantly improve design and construction consistency and efficiency, incorporating optimal design and material usage cost-effectiveness to produce integrated construction drawings and estimation documents. The Electric Graphic Work Design Tools project will be used for large NB, Subdivisions, Rule 20, Reconstruction, Capacity/Reliability, and Work at the Request of Others.

PG&E's new design tools need to be working when it converts over to its ED GIS/AM system in 2014. PG&E's proposed enhancements to the current design tool are intended only to keep the existing system running until it can convert over to the new graphic work design tools. The existing tool will not support integration with the ED GIS/AM system.

4.2.8. Advanced Applications for DCC

PG&E proposes to spend $9.5 million in capital in 2015 and 2016 for advanced applications for its DDC. PG&E's proposal includes the deployment of advanced software applications to its DDC and provides tools for integrated monitoring and control of the distribution system. Applications available in the marketplace can provide better integration between Distribution Management System and Outage Management System solutions. These applications help operators to analyze and manage planned and unplanned events, and include the following types of capabilities: Integrated SCADA control user interface; Restoration switching analysis; and Operator training simulator. PG&E classified this as a safety project but Liberty did not.

TURN contends that this project does not seem essential or necessary based on alleged benefits. TURN recommends disallowing requested capital funding of $3.8 million in 2015 and $5.7 million in 2016.

We believe this program will be another important program especially for integrating SCADA control and restoration switching analysis to support a smarter grid, accommodating growing volumes of various distributed energy and demand response resources. We acknowledge TURN's concerns, however. In addition, given the other large funding increases at issue in this GRC, we conclude that burdening ratepayers with full funding of this project has not been

sufficiently justified. We address 2015 and 2016 post-test year ratemaking in Section 12.

4.2.9. SAP Work Management Enhancements

PG&E forecasts capital costs of $1.0 million in 2013, $2.1 million in 2015, and $5.5 million in 2016, and $0.8 million in 2014 expenses for its SAP Work Management Enhancements project. The SAP Plant Maintenance (PM) Module is the platform for Gas and Electric Operations. Employees use the PM Module to create work orders, enter purchase orders, request parts, manage assemblies, plan and schedule work, and close out work orders. PG&E is bringing different departments onto the SAP platform to more fully utilize the PM Module functionalities and phase out disparate, paper-based work order processes. DRA proposes a 14% disallowance based on use of the Concept Estimating Tool.

The most expensive phase of this project is Phase 5, Operational Reporting and Analytics, $4.6 million in capital in 2016. This project will evaluate the business need for an operational reporting and decision support system and develop reports/dashboards. TURN recommends no funding for Phase 5 of this project which will evaluate the business need for an operational reporting and decision support system and develop reports/dashboards. TURN's rationale for recommending no funding is that Phase 5 is the most expensive component of a set of integrated project enhancements.

Discussion

We conclude that PG&E's proposed SAP Work Management Enhancements funding for 2014 is reasonable, and offers ratepayer benefits. We adopt PG&E's forecast for SAP Work Management Enhancements, but reduced to incorporate DRA's proposed 14% disallowance based on use of the Concept Estimating Tool, as discussed further at Section 7.8.2. We decline to approve

funding for Phase 5 of the project, which is not scheduled to be implemented until 2016.

We recognize that PG&E must redesign its work order management processes and develop standardized processes for all departments to use the PM Module and enter data in a consistent manner. This project supports the ED GIS/AM project, will improve efficiencies in work management processes and improves PG&E's ability to offset escalation in its forecast.

4.3. Applied Technology Services (ATS)

PG&E forecasts $2.151 million for 2014 expense for MWC AB in support of ATS initiatives. The ATS is a multidisciplinary team of engineers, scientists, technicians that assists various engineering and operating departments. PG&E's ATS MWC AB expense forecast includes: (1) $1 million for activity regarding electric and magnetic field issues; (2) $1 million for electronic scanning and archiving of reports and test results regarding PG&E's physical assets; and (3) $100,000 for the San Ramon Technology Center (SRTC) facility upgrade. PG&E' 2014 forecast for these activities (excluding escalation), is $1.1 million higher than 2011 costs.

PG&E's 2014 ATS capital forecast for MWC 05 includes the costs of miscellaneous tools and equipment for employees performing field and laboratory tests. PG&E's ATS forecast for MWC 78 includes the: (1) ATS performance laboratory upgrades; (2) SRTC Upgrade; and (3) SRTC parking lot. PG&E's 2014 capital forecast for these activities is $2.8 million (excluding escalation), approximately $1.0 million lower than 2011 costs. The decrease is primarily a result of the onetime purchase of equipment in 2011.

DRA proposes a reduction in PG&E's expense forecast of $1.085 million, opposing funding for the ATS Document Library Scanning and Archiving Project as well as for the SRTC facility upgrades.

DRA opposes new funding for these projects, arguing that they add little ratepayer value and lack sufficient documentation or analysis. DRA claims that PG&E does not need additional funding for SRTC Upgrades since building upgrades and modernizations are ongoing processes. DRA states that there are embedded costs for facility upgrades and that PG&E should reallocate funding from previous investments and upgrades.

DRA also recommends a $90,700 reduction to PG&E's 2014 capital forecast for MWC 05 and a $1.958 million reduction for MWC 78. ESC supports PG&E's forecasts in these areas. Liberty finds that the ATS Department "supports work efficiency, reliability and general safety." No party disputed PG&E's 2014 MWC 78 forecast of $230,000 for the ATS Performance Laboratory Upgrades. DRA accepts PG&E's 2013 MWC 78 forecast and recommends adopting PG&E's actual costs for 2012.

Because PG&E's forecast is consistent with historical costs, DRA is not taking exception to PG&E's three-year total request. PG&E requested a three-year total of $1.8 million. DRA further states that since PG&E's actual 2012 capital expenditures exceeded its forecasted 2012 expenditures, and because DRA accepts the 2012 actual expenditures, DRA adjusted its 2013 and 2014 forecast so that DRA's three-year total from 2012- 2014 equals PG&E's forecasted three-year total.

Discussion

We adopt PG&E's $2.151 million expense forecast for 2014. We conclude that the ATS document scanning project will improve system safety, reliability,

and efficiency. The SRTC upgrade will provide better use of limited space. The ATS Document Library contains records for PG&E Lines of Business (LOBs) dating back to the early 1900s. These records are deteriorating and include valuable information not readily available elsewhere. PG&E plans to scan and upload these documents to a modern records management system to support records retention and improve accuracy and timeliness of search capabilities. The project PG&E proposes to upgrade the SRTC facility by modernizing common areas built in the early 1970s. The purchase and installation of new furniture will promote modern work methods, and help maintain a safe environment for employees and visitors. We are persuaded that these qualitative benefits justify the proposed funding.

We conclude that the facility upgrades that PG&E forecasts for the SRTC are properly forecast in this GRC. Thus, we approve PG&E's capital forecast in MWC 05 and MWC 78. The proposed funding for the STRC facility is incremental to existing ongoing maintenance and is not covered within embedded funds. Previous funding in this MWC was for other specific upgrades. PG&E does not have a recurring source of funding for the SRTC upgrade.

PG&E's forecast for MWC 05 covers tools and equipment, for which costs vary year to year, as opposed to a specific project to be completed in 2012-2014. PG&E's 2011 recorded costs ($985,000) were significantly higher than PG&E's 2014 forecast. PG&E's recorded costs for 2012 exceeded PG&E's forecast for that year as well as each year thereafter, including the test year. This pattern suggests that PG&E will spend more, not less, than $645,000 in the coming years.

4.4. Electric Mapping and Records Management (MWC GE)

PG&E forecasts $31.117 million for Electric Mapping and Records Management expenses for 2014, an increase of 825% over 2011 levels. This forecast includes Base Mapping and Records Management, and four new initiatives: (1) Records Quality Assurance Program (QAP); (2) Field Asset Inventory; (3) Conversion of Paper Records to Electronic Format; and (4) Electronic Records Update to Standard Format. The proposed program will create new maps, record updates and maintain electric distribution maps, and provide mapping information for planning new services, analyzing existing services, forecasting work and maintenance of PG&E's facilities. PG&E proposes to perform a detailed inventory of its Electric Distribution System overhead and underground facilities to identify and correct all the discrepancies between actual conditions and assets in the field and its asset records on its maps and in databases.

PG&E's forecast includes $10 million for a Field Asset inventory is to identify discrepancies between actual conditions in the field and asset records; $14.2 million to convert paper records to electronic format to improve accessibility from any location, to protect against physical damage, and to provide for electronic searching; and $1 million to update existing electronic records to a stand enterprise-side format to improve search functions. PG&E used project specific estimating methods. The increase is due to initiatives to improve accuracy, completeness, uniformity, and accessibility of electric distribution system records. Some of these initiatives are in response to the IRP report issued in June 2011 and ongoing Companywide records improvement efforts.

DRA recommends a forecast of only $4.416 for MWC GE for base mapping and records management based on a five-year average (2007-2011). In all other respects, DRA opposes PG&E's forecast new initiatives for MWC GE, recommending a total reduction in PG&E's forecast of $26.701 million. DRA claims that PG&E's requested increase is unjustified based on historical levels. If incremental expenses are incurred over authorized funding levels, DRA proposes that PG&E's shareholders bear the expense.

DRA opposes additional ratepayer funding for PG&E's projects for its Field Asset Inventory, Converting Paper-Based Records to Electric Format, Updating Electric Records to Standard Format and its Records QAP to address PG&E's electric distribution mapping and recordkeeping deficiencies. DRA also opposes PG&E's proposed contingency costs associated with the above projects.

DRA recommends denying incremental ratepayer funding over historical expense levels to address PG&E's electric distribution mapping and records deficiencies. DRA claims PG&E's Electric Mapping and Records Management proposal includes the same activities associated with prudent recordkeeping and should be part of the normal, routine and on-going maintenance activities already funded by ratepayers.

DRA claims that PG&E has been authorized funding over the last 10 years to ensure critical records were maintained and preserved, by converting paper-based maps and records to electronic format. PG&E's as-built drawings (installation records) and maintenance records must be accurate, reliable, accessible, and preserved. DRA claims that PG&E failed to properly maintain and update records and databases so that extensive remedial work is now needed. DRA claims that PG&E's recordkeeping practices have been deficient since the 1970s. PG&E has had approximately 40 years to correct, verify and

compare asset records and asset field inventory, completely update records missing critical information, streamline processes for easy retrieval of records, convert all paper based records to electronic formats, and migrate/consolidate all necessary mapping record databases.

DRA thus argues that PG&E received sufficient funding during that period to address projects similar to its 2014 proposal for mapping and records corrections, upgrades, consolidations and paper record conversions to electronic format. DRA claims that PG&E decided not to use authorized funds to convert paper-based, historical, as-built drawings and maintenance records to electronic format. DRA argues that ratepayers have already funded this activity and should not be charged twice for these normal, on-going, and routine mapping and records maintenance activities already embedded in existing funds. DRA proposes that PG&E shareholders absorb the incremental cost of converting as-built drawings and maintenance records.

PG&E claims that DRA's recommendation would halt PG&E's progress towards implementing industry standard asset and risk management tools.

The CEP opposes all of PG&E's forecast initiatives (a $27.8 million reduction). CEP also recommends that the Commission open an investigation regarding PG&E's past recordkeeping practices for Electric Distribution and adopt certain requirements regarding PG&E's wireless infrastructure.

ESC supports PG&E's proposals to improve records management practices and tools, including the proposed conversion of paper-based records to electronic format. Liberty finds that although PG&E's Mapping and Records Management Program initiatives improve system safety risk levels, there is no foundation for justifying them on a cost versus benefit basis.

Discussion

We adopt PG&E's forecast for Electric Mapping and Records Management expenses for 2014 as reasonable. Although PG&E's request is for a large increase over historical levels, limiting funding to historical spending levels would not cover the expanded scope of initiatives planned. Although PG&E did not provide explicit quantification of costs relative to benefits, based on our own assessment, we conclude that the expected benefits from the project warrant approval of PG&E's funding request. As noted by Liberty, PG&E's existing mapping and asset management systems do not integrate all necessary data sets in a single system to support mobile technologies, system modeling, reporting and analysis, and overall asset management. We conclude that in order to come up to acceptable industry service standards, PG&E's mapping and records initiatives should be implemented as planned, with funding to support them.

PG&E's funding estimates were based on information from recently completed records management projects in other departments, proposals from vendors who completed similar projects at other utilities, and inventories of specific records and numbers of assets at PG&E.

We recognize that PG&E spent less than imputed amounts each year during 2007-2011 for MWC GE. The five-year average (2007-2011) was $4.416 million and the three-year average (2010-2012) was $3.714 million. During PG&E's 2011 GRC, expenses in MWC GE showed a similar declining trend due in part to implementing PG&E's Mapping and Improvement Project Phase 2 to convert older electronic and manual maps to an electronic mapping platform. We conclude, however, that PG&E has not previously received ratepayer funding for the specific new mapping and records management improvement projects being requested here. Therefore, past spending patterns for MWC GE

do not provide a basis to deny or reduce PG&E's forecasts for proposed mapping and asset management programs that take advantage of new technology and provide tools and systems to support safe and reliable service.

We decline to adopt CEP's proposal to open an investigation regarding PG&E's past recordkeeping practices for Electric Distribution.

4.5. Electric Distribution Maintenance (EDM)

4.5.1. Introduction

PG&E's EDM expense includes inspection, testing, repair and replacement of distribution facilities, and new initiatives to proactively replace aging assets that pose safety and/or reliability risks. PG&E's EDM expense forecast for 2014 of $128 million which is $13.4 million higher than 2011 costs primarily due to maintenance on new capital projects e.g., Idle Facilities Removal, Infrared Switch and Conductor Replacement and Underground Oil-Switch Replacement. PG&E's forecast covers: MWC BF - Patrols and Inspections; MWC KA - Overhead Preventive Maintenance; MWC KB - Underground Preventive Maintenance; MWC KC -Network Preventive Maintenance; and MWC BK - Maintenance of Other Equipment. PG&E forecasts increases in EDM expenses of 11% from 2011 to 2014, with the largest increases stemming from forecasted work levels for safety, maintenance, and program compliance. Forecasts of increased expenses for vegetation management reflect new environmental permitting requirements and advanced tree trimming to reduce fire risks. Other forecasted increases are due to infrared inspections to improve safety and reliability, as well as improved records management.

DRA recommends a reduction of $24.450 million to PG&E's 2014 forecast for expense work related to EDM - MWCs BF, BK, KA, KB, and KC. TURN recommends reduction of $9.803 million.[35] CCUE recommends that PG&E receive additional funding for maintenance on Critical Operating Equipment (COE). CCSF recommends that funding for Streetlight Burnouts and Streetlight Group Replacement be withheld until PG&E develops performance and reliability standards for streetlight replacement. California City-County Street Light Association (CAL-SLA) recommends a lower unit cost for streetlight burnout replacement than PG&E forecast. Liberty found that with one exception (PG&E's Infrared Conductor Replacement Program), PG&E's EDM programs appear to be effective and properly managed.

PG&E also requests approval of capital forecasts of $158.2 million of 2012, $161 million for 2013, $176.7 million for 2014, $159.8 million for 2015, and $154.2 million for 2016. EDM capital projects consist of constructing or modifying electric distribution facilities and substations, as well as improving distribution system capacity and reliability. Drivers of PG&E's forecasted EDM capital expenditure increases are for electric meters, distribution substations, underground cables, and replacing or reinforcing poles. PG&E points to demand growth; continuing to upgrade the worst-performing circuits to improve reliability; and expanding use of Supervisory Control and Data Acquisition (SCADA) equipment to monitor, control, and remotely shut off electricity during emergencies to justify its increased EDM capital forecast.

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[35] The MWC elements of EDM expense difference among PG&E, DRA, and TURN are itemized on Table 4-1 of PG&E's Opening Brief.

DRA recommends reductions of $52.887 million in 2013 and $83.939 million for 2014, to PG&E's forecast for EDM capital work related to MWCs 2A, 2B, and 2C. DRA also recommends that capital work in 2012 in MWCs 2A, 2B, and 2C be funded at 2012 recorded costs. TURN recommends reductions of $20.864 million in 2012 and of $51.312 million in 2014 to PG&E 2014 EDM capital forecast.

4.5.2. Overhead Line Maintenance (MWC 2A) and Underground (MWC 2B)

PG&E's capital work in overhead corrective line maintenance in MWC 2A consists of scheduled replacement of overhead distribution line equipment. This work improves public and system safety, employee safety, reliability and compliance by correcting maintenance conditions that could lead to equipment failure and outages, as well as potentially harmful to employees or customers. PG&E's forecast for MWC 2A is $108.68 million for 2013 and $108.67 million for 2014.

PG&E's 2014 forecast for MWC 2B is $48.416 million, including escalation. DRA recommends a total of $25.7 million in reductions to four categories of work (including escalation) in MWC 2B: (1) Underground Notifications; (2) Underground COE Notifications; (3) Underground Major Notifications; and (4) Underground Oil-Switch Replacements.

DRA recommends reductions to PG&E's capital forecasts of $33 million for 2013 and $52.7 million for 2014 with adjustments relating to: Overhead Notifications, Overhead COE Notifications; and Bird Safe Notifications. For each of these categories, recorded 2012 costs were higher than PG&E's 2012 forecast. DRA thus recommends a reduction to PG&E's 2013 and 2014 forecasts equal to the amount by which PG&E's 2012 recorded costs exceeded its 2012 forecast. On

this basis, DRA proposes reductions of $485,000 for Overhead Notifications, $2.529 million for Overhead COE, and $1.042 million for Bird Safe/Bird Retrofit - DRA's rationale for reducing PG&E's 2013 and 2014 forecasts is to keep the total approved forecast for 2012-2014 at the same level as PG&E requested in its application.

As with overhead corrective maintenance work in MWC 2A, DRA recommends that PG&E's 2013 and 2014 forecasts in MWC 2B for Underground Notifications, Underground COE Notifications and Underground Major Notifications be reduced by the amount PG&E's 2012 recorded costs exceeded its 2012 forecasts.

Discussion

We adopt PG&E's capital forecasts in MWC 2A for overhead corrective maintenance relating to: Overhead Notifications, Overhead COE Notifications; and Bird Safe Notifications. We also adopt PG&E's capital forecasts in MWC 2B for Underground Notifications, Underground COE Notifications and Underground Major Notifications. We find no basis to conclude that PG&E's higher-than forecasted spending in 2012 warrant reductions to 2013 and 2014 forecast levels for either MWC 2A or MWC 2B. PG&E's 2013 and 2014 forecasts in MWC 2A for Overhead Notifications, Overhead COE Notifications and Bird Safe Notifications are found to be reasonable and we accordingly adopt them. DRA did not challenge the appropriateness of PG&E's recorded costs in 2012. PG&E's higher-than-forecast costs in 2012 were due to (1) a higher-than-expected number of new corrective maintenance notifications, and (2) extra work not anticipated in its forecast. We also adopt funding for 2012 based on recorded amounts to provide a more accurate forecast.

4.5.3. Idle Facilities Removal (MWC 2A and MWC KA)

PG&E forecasts capital expenditures necessary to remove idle facilities in MWC 2A. PG&E's capital forecast for Idle Facilities Removal is $22.864 million in 2013 and $26.567 million in 2014 (excluding escalation). This subprogram involves removal of aging idle distribution equipment before it becomes a hazard to employees and the public.

PG&E also forecasts $3.819 million in 2014 expenses in MWC KA to investigate and review idle facilities on its system. The expenses cover desk and field reviews of equipment currently tagged as idle to assess its condition and determine if it is likely to be used in the future, or should be removed before it becomes a hazard to employees and the public. This expense is tied to PG&Es capital forecast for Idle Facilities Removal.

DRA recommends rejection of PG&E's forecasts for both the capital and expense funding of the Idle Facilities project. DRA presents a 2014 expense forecast of $5,650 for routine maintenance of idle facilities removal, based on a three-year average of PG&E's recorded expenses.

DRA recommends 2013 and 2014 capital funding of $101,000 per year based on a five-year average of historical spending, arguing that PG&E's 2013 and 2014 forecasts are not adequately supported.

TURN agrees with DRA on recommended disallowance of capital and expense funding for the Idle Facilities Removal project. If the Commission grants any additional funding, however, TURN recommends no more than $2 million per year. TURN argues that this would still be a significant increase over historical spending. TURN believes removal of idle facilities should be done when it is convenient for crews already in the field to do so.

If TURN's recommendation is not adopted for the capital expenditures for the Idle Facilities Removal Program or if PG&E is provided funds to complete its basic review of facilities, TURN proposes that the 2014 forecast of expenses for Idle Facilities Investigations be reduced to normalize test year costs to account for the rapidly diminishing cost trend through the rest of the GRC cycle. Specifically, given that PG&E's 2015 forecast is significantly lower than the 2014 forecast and the 2016 forecast is zero, TURN recommends a normalizing adjustment for the test year forecast to conform with the Commission's practice of not including one-time expenses in the test year. The normalized amount is $1.623 million, which represents a reduction of $2.196 million to PG&E's forecast.

PG&E argues that historical spending for this activity is not indicative of proposed future spending to significantly increase the number of idle facilities removed per year. In the past, PG&E monitored and maintained these idle facilities in compliance with General Orders (GO) 95, 128, and 165 requirements to maintain a safe and reliable electric distribution system, but removed very few of them.

PG&E thus has a large accumulation of idle facilities, and seeks to address that accumulation before they become older. PG&E claims no cost/benefit analysis is necessary to support the conclusion that aging facilities will present increased risk to public and employee safety and system reliability.

Discussion

We recognize that PG&E's stock of idle facilities has accumulated and will ultimately need to be removed as they age. We conclude, however, that the large increases in funding over historical levels sought by PG&E for this GRC have not been justified. PG&E has not demonstrated that idle facilities pose a safety and reliability risk to a degree that justifies costs of $22.864 million in 2013 and

$26.567 million in 2014 in MWC 2A. PG&E could only provide an example of oil seepage from transformers but could not state how often such problems actually occur.

Liberty concludes that PG&E's idle facilities do not pose a safety risk and does not classify PG&E's Idle Facilities Identification and Removal program as a safety program. Liberty stated:

> PG&E felt that idle facilities can result in safety hazards, mitigatable through removal or de-energization. Liberty felt that no observed or defined safety risk differentiating these lines from other lines was apparent. GO rule 95 requires lines temporarily out of service to be inspected and maintained in conditions that will avoid hazards. It also common practice in the industry to disconnect and ground an idle tap line or transformer.[36]

PG&E did not perform a cost-benefit study or engineering study, or identify specific idle facilities it plans to remove. PG&E previously designated idle facility removal as a low priority.

For this GRC cycle, we limit capital funding for Idle Facilities Removal to $2 million per year in MWC 2A, as proposed by TURN. This amount is more than the historical levels of spending, but less than the dramatic increase that PG&E requests. We find no basis to justify approval of funding above the $2 million limit suggested by TURN. Considering the cumulative ratepayer cost burden of other higher-priority programs being approved in this GRC cycle, we conclude that PG&E's proposed additional spending increases for idle facilities removal can be deferred at least for this GRC cycle. We may consider funding

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[36] Exhibit 168, Liberty Report at 123.

idle facilities replacement at a higher level in a subsequent GRC in view of the risks, costs, and other relevant facts at issue at that time.

Although we reduce PG&E's capital forecast, we conclude that PG&E should still move forward with its basic review of facilities in order to provide a basis to determine the appropriate removal strategy going forward. We reduce PG&E's 2014 forecast of expenses for Idle Facilities Investigations in MWC KA to normalize the test year to account for the diminishing costs forecast through the rest of this GRC cycle. PG&E's 2015 forecast is significantly lower than the 2014 Test Year forecast and the 2016 forecast is zero. We adopt a normalized 2014 expense amount of $1.623 million, which represents a reduction of $2.196 million to PG&E's 2014 expense forecast.

4.5.4. Infrared Inspection and Tags (MWC 2A and MWC KA)

PG&E forecasts 2014 expenses of $3.5 million and $10 million for Infrared Inspections and Infrared Tags, respectively, in MWC KA. PG&E also forecasts associated 2014 capital expenditures of $15.0 million for Infrared Conductor Replacement and $750,000 for Infrared Switch Replacement in MWC 2A (excluding escalation). PG&E conducted infrared inspections on a limited basis prior to 2013. PG&E now proposes to expand the infrared inspection program to cover its entire overhead distribution system. This program is designed to proactively replace deteriorated splices and spans identified during infrared inspections. The Infrared Switch Replacement program will also proactively replace deteriorated overhead switches identified during infrared inspections, which will prevent outages.

DRA recommends rejection of PG&E's requested funding for this program, arguing that PG&E did not show that the program is cost-effective and

could not identify any cost/ benefit analysis or engineering studies to justify the proposed spending. DRA notes that there is no government requirement that PG&E perform an infrared inspection of its entire system, and PG&E has not performed one in the past 20 years. PG&E was unable to identify conductors or switches subject to the program that had failed.

PG&E claims, however, that infrared inspection is the best way to identify switches, splices and spans of conductor that are prone to failure. PG&E's regular visual inspection process does not capture internal deterioration or misalignment.

PG&E's Infra-red Conductor Replacement program is coordinated with a similar program in MWC 08. Liberty states that "PG&E's two different conductor replacement programs appear to compete with, rather than complement each other, and that two reasonably aggressive programs are "both chasing the same prey." Liberty is concerned with an apparent lack of coordination between the programs, noting that the MWC 2A program appears to be directed at replacing single spans while the MWC 08 program seems to be directed at replacing multiple spans. Liberty recommends that PG&E's infrared program be limited to inspections and the generation of an asset registry, so that PG&E would not be funded for capital work in MWC 2A. Liberty also found that PG&E's forecast of the unit costs of conductor replacement of $108 per circuit foot to be unduly high. Liberty states that the replacement work can be done for about $50 per circuit foot based on workpaper data. This adjustment translates into a reduction from $570,000 to $264,000 per mile. Liberty attributes the high unit costs to PG&E's lack of identification of a suitable replacement conductor and a lack of effective program controls.

Discussion

We approve PG&E's forecasted capital and expense funding for the Infra Red Conductor Replacement program in MWC 2A and MWC KA. We conclude that the infrared conductor replacement program provides an important safety enhancement and that funding for it is appropriate, even though PG&E has not quantified a cost/benefit risk analysis. This replacement program will reduce the number of "wires down" incidents on PG&E's distribution system, thereby preventing outages and hazards to public and employee safety. Liberty found that PG&E's Infrared Conductor Replacement program contributes to system safety and improves system reliability by identifying heated switches. Liberty believes, however, that addressing deteriorated conductors will take significantly more resources than PG&E forecasts in this GRC. PG&E's forecast in this GRC reflects only the initial results of its efforts to develop a multi-year plan for replacement of key assets.

We are satisfied with PG&E's explanation of how conductor replacement work funded in MWC 2A and MWC 08 is coordinated and not duplicative. PG&E explains that the two programs in MWC 2A and MWC 08 are separated only for accounting purposes, and that replacement work will be performed by the same construction personnel and on the same basis. A single span replacement will apply where conditions require more immediate attention, and replacement of longer sections of conductor will apply in areas where PG&E has identified multiple spans of deteriorated conductor. We thus conclude that PG&E's requested funding for overhead conductor replacement forecast in both MWC 2A is not duplicative of forecast costs in MWC 08.

We are also satisfied with PG&E's explanation of the reasons for the higher unit costs of the Infrared Conductor Replacement Program. As noted by PG&E,

the forecast reflects a mix of projects of different wire sizes. Total funds forecast reflect this mix of projects.

4.5.5. Incandescent Streetlight Replacement (MWC 2A)

PG&E proposes funding to replace an obsolete incandescent series streetlight system in the City of San Francisco. Manufacturers no longer make the parts required to keep these series streetlights operational, which has led to long outages. PG&E's 2013 and 2014 capital forecast for this program is $7.25 million and $7.24 million, respectively (excluding escalation). PG&E has approximately 1,180 incandescent streetlights that require replacement, and its proposed replacement program funding covers a three-year period from 2012-2014.

DRA recommends 2013 and 2014 funding of $2.85 million per year which represents the amount PG&E spent on the program during 2012. DRA also believes that PG&E's unit cost forecast, based on a pilot project, is likely to drop drastically when PG&E begins doing a larger volume of work. DRA believes that the actual 2012 level of work, which was below PG&E's forecast, shows PG&E is not committed to executing the program at the pace set out in its forecast.

PG&E disputes DRA's reductions. PG&E does not expect economies of scale with regard to the construction work that makes up the bulk of incandescent streetlight replacements. Under its regular program of streetlight installation and maintenance, PG&E already buys in bulk the transformers, cables and bulbs it will use to replace the obsolete series streetlights. PG&E denies that completion of relatively few streetlights in 2012 shows a lack of commitment to completing the work forecast for 2013 and 2014. PG&E's work in

2012 focused on preparatory work for future conversions and replacements rather than on completing replacements.

PG&E claims that its 2013 and 2014 forecast funding is necessary to complete incandescent replacements in a timely fashion, and that DRA's limited funding would prolong the replacement process up to nine years, causing undue hardships on affected customers. CCSF supports PG&E's plans to replace these obsolete streetlights, but in view of PG&E's history of re-prioritizing streetlight revenues towards other activities, CCSF proposes that approval of PG&E's funding the conditioned on its actually performing these replacements.

Discussion

We conclude that PG&E's plan is reasonable for the replacement of the San Francisco incandescent streetlight. DRA's recommended funding limitations would require nine years for PG&E to complete the replacement of its obsolete series streetlight system. Such a delay in completing replacements would prolong the risks of lengthy outages, and possibly complete failures of portions of the system due to the unavailability of spare parts, including special bulbs used in these types of lights.

We conclude that PG&E has reasonably quantified the expenditures required to complete the replacements. Given the concerns raised by CCSF, however, we question whether PG&E will spend the adopted funds for streetlight replacements during the 2014-2016 cycle, or will choose to reprioritize the use of funds for some other purpose.

Accordingly, we authorize PG&E to track actual expenditures incurred for replacement of the San Francisco incandescent streetlights in a memo account, capped at PG&E's proposed 2013 and 2014 capital spending forecast for this program. As a revenue requirement for 2014, we will adopt the level forecasted

by PG&E. We expect PG&E to spend the authorized funds for this designated purpose and not to postpone spending based on claims that the money was spent on other projects. In the next GRC cycle, we will require PG&E to provide an accounting of its progress in completing the forecasted streetlight replacements. To the extent that the memo account records indicate that PG&E failed to spend the money for this designated purpose, we will make the appropriate reductions in the authorized revenue requirement the next GRC.

4.5.6. Permit Updates (MWC 2A)

PG&E forecasts costs for Permit Updates to maintain rights-of-way easements for distribution lines on United States Forest Service lands. PG&E forecasts $200,000 in 2013 and $388,000 in 2014 in MWC 2A for capital work related to Permit Updates (excluding escalation).

DRA recommends 2013 and 2014 capital funding of $67,500 per year. PG&E's 2012 recorded costs were higher than its 2012 forecast. DRA's recommendation reduces PG&E's 2013 and 2014 forecasts by the excess of PG&E's 2012 recorded costs relative to its 2012 forecast. DRA adjusted its 2014 forecasts so that DRA's 2012-2014 total equals PG&E's forecasted total. Therefore, DRA recommends capital expenditures of $565,000 for 2012, $67,500 for 2013, and $67,500 for 2014. PG&E opposes DRA's adjustment, arguing that DRA presents no reasoned basis for assuming that 2012 variations will lead to lower forecasts for 2013 and 2014.

TURN recommends a $34,287 increase to Permit Updates in MWC 2A, claiming that PG&E underestimated the portion of Permit Update costs that are historically recorded as capital and overestimated the portion recorded as expense. PG&E accepts TURN's recalculation of the ratio of expense and capital

in the forecast for Permit Updates, and its recommendations for both MWC KA and MWC 2A.

Discussion

We adopt PG&E's forecasted capital and expense amounts of $388,000 and $50,000 for 2014 Permit Updates in MWC 2A and KA, respectively, consistent with TURN's recalculations of the ratio of expense and capital. TURN recalculated the forecast of Permit Updates expenses based on average recorded costs from 2007-2012 for a 2014 forecast of $50,000, a reduction of $250,000. PG&E agreed to TURN's adjustment to its Permit Updates expense forecast in its rebuttal testimony. We thus adopt a test year forecast of $50,000 for MWC KA.[37] We decline to adopt DRA's adjustments. We find insufficient basis to reduce 2013 and 2014 forecasts based solely on recorded spending during 2012.

4.5.7. Underground Oil Switch Replacements (MWC 2B and MWC KB) -

PG&E requests $25 million in 2014 capital spending in MWC 2B to proactively replace potentially hazardous, older-vintage underground oil-filled switches. PG&E also forecasts related 2014 expense of $1.5 million in MWC KB. Approximately 2,500 of these switches were manufactured prior to 1970, and another 20,000 switches were manufactured prior to 1981. There have been more than 250 failures of oil-filled switches on PG&E's system reported for root cause analysis since 2000, many of which have been catastrophic, including older-vintage switches. PG&E forecast covers replacement of 500 of these switches per year starting in 2014 after PG&E conducts a condition-based

assessment. PG&E forecasts unit counts for investigations of 2,500 units in 2012 and 4,300 units in each of 2013 through 2016 for a total unit count of 19,700 in the five years.

DRA recommends reducing PG&E's 2014 forecast by $20 million, down to $5 million, corresponding to replacement of 100 switches per year. DRA and TURN claim that PG&E has not sufficiently supported the proactive replacement of switches at the pace proposed. DRA and TURN also oppose authorizing any incremental expense relating to these replacements.

TURN believes that PG&E has not justified replacements at the rate that it proposes, but agrees with DRA's forecast of $5 million per year covering replacement of 100 switches per year. TURN believes that some capital switch replacement funding that is addition to its embedded funding may be reasonable.

PG&E characterizes its forecast as a focused effort to inspect, analyze, prioritize, and replace aging infrastructure elements, rather than a piecemeal attempt at maintenance. PG&E claims this is new work that cannot be funded out of an existing budget for corrective maintenance. PG&E claims that TURN and DRA unduly downplay the reliability impacts and safety hazards associated with a violent switch failure. PG&E claims that it is generally more expensive to replace facilities on an ad hoc basis after they fail than to replace them proactively.

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[37] PG&E's numbers in the Comparison Exhibit and Opening Brief do not reflect TURN's errata adjustments and are modified to reflect the $250,000 reduction for a test year forecast of $50,000.

Discussion

We conclude that underground oil switches need to be replaced proactively, but question how rapidly such proactive replacement should occur in view of the costs. PG&E explained the general benefits of replacing oil switches, but did not quantify the risk-adjusted value of its proposed rate of replacement in relation to the cost burden on ratepayers. To the extent that switch failures cause outages, PG&E has not estimated the reliability improvement expected from the program, or compared the hypothetical improvement to the costs of this and other reliability programs.

Although we believe that some level of proactive replacement is warranted, we are concerned that PG&E's proposed rate of replacement reflects an unjustified cost burden on ratepayers relative to mitigation of risks. Even with replacement of 500 oil switches per year, as proposed by PG&E, a number of years would be required to replace all switches. During those remaining years, some residual risk of switch failure exists under either PG&E's or DRA's proposal. The difference between the proposals is a matter of degree of risk mitigation versus cost.

DRA's and TURN's recommendation to fund replacement of only 100 oil switches per year is unreasonably low. At that pace of replacement, some of the 2,500 pre-1970 switches currently on PG&E's system would still remain 25 years from now, at which point they would be at least 65 years old. In any event, the longer the oil switches remain, the greater the risk of failures, with the associated reliability and safety risks. On the other hand, while PG&E's proposal would fund a more rapid rate of replacement, it would place an undue cumulative cost burden on ratepayers during 2014-2016 GRC cycle during a period that many other new high programs will be increasing ratepayer costs.

We conclude that the appropriate 2014 funding level lies between the extremes proposed by either PG&E or DRA. We thus adopt a 2014 funding level for replacement of 250 oil switches per year, which is half of the rate that PG&E proposes, but more than twice what DRA and TURN propose. Adopting this funding amount resolves parties' conflicting proposals, and provides some momentum to move forward with proactive replacement of switches, while moderating the cumulative cost burdens borne by ratepayers for the 2014-2016 GRC cycle. We recognize that funding a more rapid rate of oil switch replacement may need to be considered for a subsequent GRC cycle in order to complete the replacement of these switches within a reasonable time, consistent with the risks in relation to customers' capacity to bear cost increases.

We adopt PG&E's 2014 expense forecast of $1.5 million relating to oil switch replacements in MWC KB. Whether it is replacing 500 switches or 100, PG&E will still need to inspect and assess all candidates for switch replacement to properly prioritize replacement.

4.5.8. SCADA Safety Monitoring (MWC 2C)

PG&E's forecast for the SCADA Safety Monitoring subprogram for MWC 2C is $8.0 million in 2014 and $5.056 million in 2013 (excluding escalation). This subprogram covers the installation of upgraded SCADA capability on PG&E's networked distribution system in San Francisco and Oakland. The remote monitoring and control provided by the SCADA will allow PG&E to detect and respond to equipment overloads and prevent failures before they occur, improving the safety and reliability of the network.

DRA agrees with PG&E's 2012 forecast of $7.1 million, but recommends that PG&E's 2013 and 2014 forecasts for SCADA Safety Monitoring be reduced

by the amount by which PG&E's 2012 recorded expenditures exceeded its 2012 forecast. DRA's forecast for both 2013 and 2014 is thus $4.1 million per year.

PG&E explains that the higher-than-forecast expenditures in 2012 was due to a program change after the forecast was prepared.

Discussion

We adopt PG&E's forecast of SCADA monitoring for 2012 as agreed to by DRA. For 2013 and Test Year (TY) 2014, we approve $5.056 million and $8.0 million, respectively, for SCADA monitoring capital costs due to the project being critical for safety. As explained by Liberty (at 148), SCADA systems serve a critical role in monitoring and controlling widespread electric grids, and provide real time data and control functions for system operators. SCADA installations provide a critical safety tool for mitigating the down-wire risk to which the PG&E system is particularly vulnerable. For this particular program, we conclude that PG&E's historical costs ($0.4 million in 2009, $3.2 million in 2010 and $8.2 million for 2011) along with $7.1 million in 2012 actual recorded costs supports more test year spending needs than DRA has proposed. PG&E plans to increase feeder SCADA installations from 2014 through 2016, deploying an average of 50 new SCADA operable line switches per year at key locations on the distribution system to isolate portions of the system experiencing higher than average incidents of wires down. This equipment will allow operators to de-energize electrical lines more quickly.

4.5.9. Network Transformer and Protector Replacement (MWC 2C)

PG&E's forecast s $6.193 million in 2013 and $6.7 million in 2014 (excluding escalation) for replacing degraded network transformers (and associated network protectors) and/or replacing transformers in high-risk

situations (i.e., located in high-rise buildings) with lower risk units. For this work, DRA recommends 2013 and 2014 funding of $4.806 million per year, a $1.387 million reduction from PG&E's 2013 forecast and a $1.894 million reduction from PG&E's 2014 forecast. DRA claims PG&E's forecast is not in line with historical spending. PG&E's 2012 spending was less than half of its forecast. DRA recommends 2013 and 2014 funding at the level of a three-year (2010-2012) average of historical costs.

Discussion

We adopt PG&E's 2014 forecast for Network Transformer and Protector Replacement work. We conclude that PG&E provided adequate explanations of the need for increased spending levels in view of the increased scope of high-rise work. We find that historical cost levels are insufficient to fund PG&E's planned expansion of Network Transformer and Protector Replacement work. Future work will require replacement of transformers in high-rise buildings, which is more expensive than below-grade replacements. As PG&E explains, its below-forecast spending in 2012 was an anomaly. PG&E had to temporarily stop replacing network transformers in mid-2012 due to internal gassing of new explosion resistant transformers used for the replacements. The previously forecasted work was expected to resume in 2013.

4.5.10. Network SwivelocTM Manhole Cover Replacement (MWC 2C)

PG&E forecasts $5.527 million, $4.5 million, and $3.5 million for its Network SwivelocTM Manhole Cover Replacement in 2012-2014, respectively.

DRA agrees with PG&E's 2012 forecast, but recommends that PG&E's 2013 and 2014 forecasts for the SwivelocTM program be reduced by the amount

overspent for the 2012 forecast. PG&E claims that DRA provided no reason why PG&E would likely spend less than forecast for 2013 and 2014.

Discussion

We approve PG&'s 2012-2014 capital forecasts for the Network SwivelocTM Manhole Replacement Program. This project promotes system safety by replacing solid and grated manhole covers with hinged venting manhole covers (trade name SwivelocTM) designed to stay in place in the event of a vault explosion, thus reducing the risks associated with projectile damage and emission of hot gases. We find no basis to reduce PG&E's 2013-2014 forecasts based on the amount overspent during 2012. PG&E continues to anticipate spending for this program at forecast levels in 2013 and 2014.

4.5.11. Overhead Preventive Maintenance and Equipment Repair (MWC KA)

PG&E's forecasts $5.405 million for the Overhead Line Equipment Inspected and Tested subprogram. This subprogram consists of visual inspection and/or testing of reclosers, capacitor banks, voltage regulators, automatic transfer switches, and SCADA equipment. PG&E forecasts increased spending to inspect and test additional switches associated with FLISR equipment installed as part of PG&E's Cornerstone project.

TURN recommends a $1.214 million reduction. TURN claims that PG&E has historically over-forecast this activity and should have included cost savings from a 2010 reduction in the testing frequency of certain equipment in its 2011 GRC application. TURN argues that the incremental cost for PG&E's inspection and testing of new FLISR installations should be funded out of these undisclosed cost savings.

PG&E responds that it should not be penalized for experiencing lower than anticipated costs in the 2011 GRC. PG&E denies knowing at the time of its 2011 GRC application that it would be reducing testing frequencies. Also, when instituting the new testing regime, PG&E did not know there would be cost savings. The new testing procedures were more detailed and required more documentation. PG&E had not assessed whether less frequent but more extensive testing would reduce or increase costs.

Discussion

We conclude that PG&E's 2014 forecast of $5.405 million for the Overhead Line Equipment Inspected and Tested subprogram is reasonable and adopt it. We conclude that PG&E has provided adequate explanations as to the reasons why its spending in prior years was lower than forecast. PG&E explains that lower-than-forecast spending was due primarily to its decision in 2010 to change the testing frequency for capacitors and reclosers from twice per year to once per year.

4.5.12. Streetlight Burnouts and Group Replacements (MWC KA)

Streetlight Burnouts is a routine maintenance subprogram that replaces burned out streetlight lamps. PG&E's Streetlight Group Replacement proactively replaces streetlight lamps in a particular area before they burn out. PG&E's forecast for 2014 for Streetlight Burnouts is $8.761 million (excluding escalation), the amount of its 2012 recorded adjusted costs.

For Streetlight Burnouts, DRA recommends a $2.83 million reduction to PG&E's forecast. DRA claims PG&E's increased investment in group replacements should reduce the number of streetlight burnouts. PG&E responds that while group streetlight replacements can reduce the number of streetlight

burnouts, there is no direct correlation between the two programs, and benefits from group replacement are not realized for several years. PG&E claims its forecast increase in group replacements is not likely to significantly affect the burnout rate.

CCSF recommends the PG&E's forecast for Streetlight Burnouts and Streetlight Group Replacement not be funded until PG&E develops specific reliability goals and performance commitments. CCSF recommends that PG&E be required to: (1) report its performance regularly to the Commission and requesting municipalities; (2) consistently meet its performance goals as a condition of approving PG&E's forecasts; and (3) refund some revenue to customers through a mechanism similar to PG&E's QAP if PG&E fails to meet any performance goal for two consecutive months.

PG&E claims that it has already instituted new performance goals, implemented new tracking tools, and created a dedicated group to address streetlight burnout performance. PG&E has set performance goals to repair 90% of streetlight burnouts within five days, and complete 75% of underground and/or cable repairs related to streetlights within 30 days. PG&E does not believe codification of these goals is necessary given that it has dedicated personnel working on burnout performance. PG&E expresses a willingness to draft and provide a written description of these goals. At the time of evidentiary hearings in this proceeding, however, PG&E did not have a written copy of these performance goals.[38]

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[38] Exhibit 204 (DR CCSF 004-13(a), stating: "PG&E does not have a written copy of these performance goals." and DR CCSF 004-13(b)).

Since PG&E's performance goals are unwritten, CCSF raise concerns that: (a) PG&E has not properly communicated the performance goals to relevant employees, (b) employees may not be kept aware of changes or be able to refer to the goals; (c) PG&E could change the goals at any time, and (d) streetlight customers, the public and the Commission have no way of verifying PG&E's performance relative to the goals.

PG&E claims its performance in relation to these goals is irrelevant to consideration of whether to fund PG&E's streetlight maintenance activities. PG&E has failed to identify how it will report ongoing performance transparently, or be held accountable if its performance lags.

CAL-SLA recommends that PG&E's unit costs for Streetlight Burnouts for 2014 be reduced to $6.08 million, based on 2011 recorded unit costs of $308. PG&E's 2014 forecast is $325, based on its 2011 unit cost of $308, plus a forecast increase. PG&E's 2012 recorded unit cost was $316, halfway between 2011 recorded and its 2014 forecast costs. PG&E argues this is consistent with the ongoing upward trend in streetlight burnout unit costs, and supports PG&E's 2014 forecast.

CCSF asks that the revenues approved for PG&E's streetlight maintenance be attached to some specified level of service that includes an enforcement mechanism for local municipalities. CCSF seeks a commitment that PG&E reduce the frequency and duration of streetlight outages in those parts of the service territory that currently experience the lowest levels of service, or report regularly on its performance to the Commission and requesting municipalities.

CCSF also proposes that PG&E rates be subject to refund similar to refunds available in PG&E's Quality Assurance Program (QAP). Under the QAP, PG&E provides a credit to residential customers in the event that PG&E's

conduct is deemed substandard. Although the QAP is only available to residential customers, CCSF argues that the principle of customer compensation for substandard service applies all customers. CCSF argues that when the level of service falls below any performance goal for two consecutive months, PG&E should provide a performance deficiency credit to the affected customer in the next monthly invoice.

Discussion

We adopt PG&E's Street light Burnout expense forecast. We conclude that DRA's proposed funding would not provide for timely replacement. Until the system is replaced, there will be continued lengthy outages, and possible complete failures of portions of the system due to the unavailability of spare parts, including special bulbs used in these types of lights.

We also require that PG&E formally produce in written form its performance goals relating to street lighting replacements. PG&E shall also be required to: (1) report its performance regularly to the Commission and requesting municipalities; and (2) consistently meet its performance goals.

PG&E currently tracks streetlight maintenance activities pursuant to a set of internal performance goals developed in 2012. These performance goals call for repair of 90% of streetlight burnouts within 5 days, and completion of 75% of underground and/or cable repairs related to streetlights within 30 days. We shall formally hold PG&E responsible for adhering to these goals that is has already established on a voluntary basis. We shall require PG&E to publicly report its performance in meeting these goals to the Commission and requesting municipalities on an annual basis.

At this time, however, we do not believe the record is sufficiently developed to adopt CCSF's proposal for payment of a deficiency charge to

streetlight customers when PG&E fails to meet performance standards for two consecutive months in a municipality. Depending on the results of PG&E's public performance reports prescribed above, however, we may further consider imposing such a deficiency charge in the next GRC.

4.5.13. Insulator Washing

PG&E's 2014 forecast for insulator washing is $459,000 (excluding escalation). Insulator washing prevents contamination from building up to the point where it might cause outages or pole fires.

DRA recommends funding of $52,000, based on a three-year average (2009-2011) of PG&E's recorded expenses. DRA argues PG&E did not adequately support its request for funding above historical levels.

PG&E washed relatively few insulators in 2010 and 2011, but expects washing more insulators in 2014, mostly due to plans to expand the scope of the insulator washing program beyond the coastal areas where it had performed insulator washing in the past.

We conclude that PG&E's 2014 forecast for insulator washing is reasonable and adopt it. The safety and reliability benefits of increased insulator washing justify approving PG&E's forecast for this activity.

4.6. Pole Test, Treat, Restoration and Joint Utilities Coordination

PG&E's 2014 forecast expense for Pole Test and Treat, Pole Restoration and Joint Utilities Coordination Programs in MWC GA is $15.05 million, including

escalation.[39] PG&E's forecast is $8.5 million higher than in 2011 due to an increase in the forecast number of poles requiring inspection between 2012-2014.

Electric pole inspections and treatment are needed to provide safe and reliable electrical service to customers. When an inspection shows that a pole does not meet the strength requirements of GO 95, PG&E restores it when feasible. If a pole cannot be restored, it is replaced as part of the capital program in MWC 07.

PG&E conducts pole inspection on a 10-year cycle, with the current cycle scheduled to end in 2014. To complete its current 10-year pole inspection cycle by 2014, PG&E increased the number of pole inspections starting in 2012 to work down a backlog of deferred inspections from prior years. PG&E's 2014 forecast was originally assumed 312,500 pole inspections to be conducted per year. PG&E subsequently revised its forecast based on the assumption of 300,000 pole inspections per year during 2013 and 2014. A level of 300,000 poles must be inspected during 2013 and 2014 is necessary in order to complete the current10-year inspection cycle.

Once the backlog is completed, PG&E plans to complete a subsequent 10-year inspection cycle covering approximately 2.35 million poles, or 235,000 poles per year. Thus, the expected number of pole inspections PG&E plans to perform annually after 2014 should decrease to 235,000 per year.

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[39] PG&E originally forecast $16.1 million in 2014 for expenses for pole test and treat, pole restoration and joint utilities coordination activities costs. In Rebuttal, PG&E reduced its forecast by $1.1 million (to $15.1 million) to account for additional joint pole credits to correct an assumption regarding joint pole cost recovery.

DRA considers PG&E's level of inspections above 235,000 poles per year to be the deferred maintenance that results from this backlog. DRA recommends a reduction in PG&E's 2014 forecast expense of $2.783 million to exclude this deferred maintenance. DRA claims that shareholders, not customers, should be responsible for funding this deferred maintenance. DRA argues that the Commission has increasingly been reluctant to authorize ratepayer funding for projects for which funding was previously authorized, but then deferred.

DRA claims that to maintain an appropriate pace for its 10-year inspection cycle, PG&E should have consistently inspected 235,000 poles per year. DRA claims that 235,000 poles per year is a more realistic forecast given the historical rate of pole inspections, and represents a normalized test year forecast.

DRA argues that by providing funding limited to 235,000 pole inspections in 2014, ratepayers only pay once for routine maintenance. Shareholders thereby absorb costs for inspections associated with backlogged poles and deferred maintenance.

PG&E claims that DRA's recommendation is unfair and would deprive it of needed funding for pole inspections for 2014. PG&E also argues that DRA's proposed normalization is inappropriate given that there are likely to be other corresponding one-time projects in attrition years that would correspond to PG&E's higher pole inspection forecast in 2014.

In addition to DRA's proposed reductions, TURN recommends a $1.6 million reduction for uncollected joint pole credit payments. PG&E partially agrees with TURN's recommended reduction to its Joint Pole Credits forecast, though for different reasons than those offered by TURN.

PG&E forecasts receiving approximately $1.6 million in joint pole credits in 2014, with a corresponding reduction in its Pole Test and Treat forecast. TURN

thought PG&E stated in a data request response that it only collects 50% of what it is owed from joint pole owners. On that basis, TURN argued that customers should be credited an additional $1.6 million. PG&E claims that TURN's interpretation of the data response was incorrect. PG&E recovers 100% of the joint owner costs it is entitled to recover.

PG&E, however, expects to eventually recover most, if not all, of those other joint owners' share of joint pole costs, PG&E concluded it would be appropriate to revise its joint pole credits forecast upward based on an assumption that it will ultimately recover 100% of recoverable joint pole costs.

Based on this revised assumption about the percent of joint pole costs that will be recoverable, and PG&E's current forecast level of Pole Test and Treat work, PG&E anticipates receiving an additional $1.067 million in joint pole credits. PG&E's reduced its 2014 forecast for MWC GA by a corresponding amount. However, if the Commission approves reduced funding for Pole Test and Treat work, there would be a corresponding decrease in joint pole credits that would partially offset the reduction.

Discussion

We recognize that PG&E needs to complete an accelerated level of pole inspections during 2013 and 2014 at the level of 300,000 per year in order to complete its 10-year inspection cycle on schedule. We conclude that timely completion of this level of inspections is appropriate from an operations perspective to promote safe and reliable service. For ratemaking purposes, however, we conclude that the portion of 2014 forecast expense for pole inspections that exceeds the 235,000 pole amount constitutes deferred maintenance that should be paid for out of shareholder retained earnings.

We thus adopt DRA's proposal to limit ratepayer funding to cover only up to 235,000 pole inspections in 2014, for a $2.783 million reduction to PG&E's forecast for MWC GA. We conclude that pole inspections in excess of 235,000 poles per year represent deferred maintenance. We agree with DRA that ratepayers should not be responsible for the deferred maintenance costs on backlogged pole inspections that were previously funded by ratepayers. Annual inspection of 235,000 poles represents a normal test year figure that should be funded by ratepayers in TY2014.

Although PG&E was authorized funds for pole inspections during prior GRC cycles, PG&E deferred spending on pole inspection work during those cycles in conjunction with performing unanticipated work in other areas. In some cases, PG&E had no discretion to delay or not perform work, such as for emergency recovery. PG&E claims its forecast work in this GRC is to perform the inspections that it had to postpone, and that customers are not paying twice for the same pole inspections twice.

We do not accept PG&E's claim that it had no choice but to postpone pole inspections as a result of other unanticipated obligations. Even assuming that other unanticipated work was of a higher priority, PG&E fails to demonstrate that such obligations for higher priority work forced the postponement of forecasted pole inspections. PG&E voluntarily chose not to perform previously forecasted pole inspections. Obligations to complete unforeseen projects deemed to have a higher-priority does not explain why PG&E shouldn't (or couldn't) also fund lower-priority projects (such as pole inspections), particularly if such projects had previously been found necessary to provide safe, reliable service. PG&E offers no satisfactory explanation as to why in GRC cycles before 2011, it

couldn't have funded BOTH higher priority projects AND the pole inspections funded by ratepayers.

We recognize that PG&E's earned rate of return may have been lower as a result of spending more money on pole inspections in addition to other higher priority work. The risk of earning a lower return, however, does not justify PG&E's choice to allow a pole inspection backlog to develop at ratepayer expense. In summary, we adopt DRA's proposed reduction.

We agree with TURN's that ratepayers should be credited with 100% of the pole test and treat fees that are due from Joint Owners. However, as explained by PG&E, TURN's recommendation to reduce the original 2014 forecast for MWC GA by $1.6 million was based on an incorrect interpretation of a PG&E data request response, in which TURN believed that PG&E only credited ratepayers with 50% of joint pole credits. PG&E's original application forecast assumed PG&E would recover 100% of joint owners' share of joint pole costs, but only for the 60% of jointly owned poles that are jointly owned with AT&T. PG&E calculated the forecast this way because AT&T pays PG&E its share of joint pole costs regularly, while payments from other joint pole owners, who co-own the other 40% of jointly owned poles, are more sporadic. Since PG&E expects to eventually recover most, if not all, of those other joint owners' share of joint pole costs, PG&E concluded it would be appropriate to revise its joint pole credits forecast upward based on an assumption that it will ultimately recover 100% of recoverable joint pole costs. As such, PG&E recalculated this expense in response to TURN's testimony, as a reduction of $1.067 million to its forecast for MWC GA. Since we adopt a lower pole inspection forecast for MWC GA, however, we correspondingly reduce the joint pole credit amount in proportion

to the reduced forecast amount for Pole Test and Treat work, resulting in an adjustment of $0.232 million.[40]

4.7. Pole Replacements

PG&E forecasts pole replacements in MWC 07 of $69.578 million for 2014 and $159.798 million for 2013, including escalation. PG&E agrees to accept its 2012 recorded costs and revised its 2012 forecast accordingly. PG&E forecast $69.6 million in 2014 for pole replacement work.

PG&E's 2014 forecast is lower than 2011 spending because in 2011, PG&E was replacing a higher than "steady state" number of poles to reduce an accumulation of poles scheduled for replacement in prior years. PG&E is continuing efforts begun in the last GRC cycle to complete the replacement of poles that had been scheduled for replacement in prior years. As part of this initiative, PG&E's plans to replace about 25,000 poles in 2012 and 2013. After completing this work, PG&E forecasts that the number of pole replacements will decrease to a "steady state" of approximately 6,000 poles per year, beginning in 2014.

For 2014 Pole Replacements, PG&E forecast units of work for the year and unit cost to perform the work. The units of work calculated for 2012 and 2013 reflect PG&E's effort to eliminate the backlog of pole replacements. By 2014, PG&E plans to reach a consistent level of pole replacement work.

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[40] The $0.232 million adjustment to the joint pole credit results from reducing the ($0.735 million) credit attributable to PG&E's pole inspection forecast by 31.48% (%2.783 million reduction/$8.840 million forecast = 31.48%).

For 2012, DRA agrees with funding for MWC 07 at the level of PG&E's 2012 recorded costs. DRA also agrees with PG&E's 2014 forecast for pole replacements of $69.578 million, except for a reduction of $37,000 based on DRA's different methodology for calculating escalation rates (2.61% instead of 2.75%). No other party disputes PG&E's 2014 forecast.

For 2013 funding, however, DRA recommends using the same level as PG&E forecasts for 2014, resulting in an $83.617 million reduction to PG&E's 2013 forecast. DRA claims it is unreasonable to authorize increased expenditures for 2013 to eliminate PG&E's pole replacement backlog because PG&E deferred this work in previous years. Because authorized pole replacements were deferred in previous years, DRA concludes that additional work above that amount forecast by PG&E in 2013 represents deferred maintenance backlog that should be shareholders' responsibility.

DRA argues that PG&E caused the backlog, and exacerbated the issue by spending far less than was authorized for pole replacements. If PG&E had not deferred pole replacements earlier, and had not compounded the backlog by spending less than authorized, DRA argues, the need to address the backlog problem would have likely never occurred. From 2007 through 2011, PG&E spent $206.5 million less than was authorized for pole replacements. DRA thus argues that since PG&E caused the backlog by repeatedly spending less than was authorized, ratepayers should not again pay for this deferred maintenance in this GRC. DRA thus recommends reducing PG&E's projected capital expenditures for pole replacements by $83.617 million for 2013. Since PG&E bases 2014 capital expenditure forecasts on a steady state spending, i.e., excluding escalation of $67.816 million, DRA proposes the same steady state level of expenditure be adopted for 2014 funding.

DRA explains, however, that its recommendation for a reduced funding level does not mean that the pole replacement backlog problem should be ignored or delayed to a future GRC.

PG&E disputes DRA's claim that ratepayers pay twice for the same pole replacement work. PG&E explains that funds previously authorized in rates for pole replacements were redirected to other work which PG&E deemed to warrant higher priority. PG&E argues that managing a large complex utility requires the flexibility to shift funds to higher priority work that was not anticipated when the forecast was originally prepared or adopted. PG&E explains that it has more work than it forecast in nondiscretionary areas, it must shift funds and resources from other areas to meet those needs.

PG&E concedes spending less than GRC-imputed amounts for pole replacements from 2007 to 2010. However, in 2011, PG&E spent almost $30 million more than imputed in the 2011 GRC. Although PG&E's 2014 GRC forecast $155.7 million for Pole Replacement spending during 2012, the imputed amount for 2012 was only $53.514 million (2011 GRC settlement). While PG&E's 2012 recorded costs of $119.316 million were about $35 million (or $29 million calculated by DRA) below PG&E's most recent 2012 forecast, they were more than $65 million above the capital amount imputed from the 2011 GRC decision.

DRA claims PG&E's forecast would result in customers being "charged twice for routine and on-going maintenance work that was deferred by PG&E." PG&E responds that it is not asking customers to pay twice for the work forecast for MWC GA. PG&E reduced some of its pole inspection work in prior years in order to perform unanticipated work in other areas, including areas where PG&E has no discretion to delay or not perform work, such as emergency recovery. PG&E argues that it should not be required to implement the workload in its

GRC forecast in an inflexible matter, but should be allowed the flexibility to reallocate its resources in response to emerging priorities.

PG&E has forecast work in MWC GA in this GRC to perform the inspections that it had to postpone before, and claims that customers are not paying twice for the same inspections.

CCUE claims that PG&E's replacement of aging poles is not keeping up with the Average Service Life (ASL) of 42 years. CCUE recommends that PG&E replace an additional 19,000 poles per year, at an additional cost of $218.367 million per year in capital, adding $19.7 million to the revenue requirement in 2014.

PG&E does not oppose CCUE's recommended increase in the forecast, but explains that its current pole replacement program adequately addresses deteriorating poles. TURN opposes CCUE's recommendations, but agrees with PG&E that its current program does not need to be accelerated. Pole life is actually increasing and poles are not replaced merely on the basis of their age but rather based on their status, as determined by in-person inspections, and there is no need to accelerate pole replacements.

Discussion

We adopt PG&E's pole replacement forecasts for 2012 and 2014. As discussed below, we adopt DRA's proposed reductions for 2013. We decline to adopt CCUE's proposal to increase ratepayer costs beyond the level PG&E proposes to cover its rate of pole replacements. CCUE argues that PG&E is not replacing poles quickly enough and recommends a further increase by $218.367 million for a total 2014 forecast of $287.945 million ($19.7 million increase in the test year). CCUE recommends that PG&E replace an additional 19,000 poles per year, adding $19.7 million to the revenue requirement in 2014.

PG&E's poles are not replaced based only upon their age but rather based on their status, as determined by in-person inspections to meet strength and loading requirements. Many factors are working towards increasing the length of pole life, including regular inspections under GO 165, more widespread use of restoration techniques, more widespread use of pole treatments such as through-boring, and software modeling of pole strength. A faster rate of pole replacements would make the system incrementally more reliable, but we are not persuaded that the additional cost burden that CCUE proposes to impose on customers is justified in terms of reliability benefits.

As discussed above in connection with our treatment of pole inspection deferrals, we conclude that it is appropriate from an operational perspective for PG&E to accelerate its pole replacements as necessary to reduce the prior back log. We do not believe, however, that ratepayers should be burdened with all of the deferred maintenance costs incurred to reduce that prior backlog. Funds were originally collected from the ratepayer based on representations that certain pole replacements were warranted to provide safe and reliable service. Yet, PG&E did not spend all of the funds to complete the designated work. The fact that PG&E must pay for a higher priority activity or program, however, does not nullify or extinguish its responsibilities to fund forecasted programs unless such work is deemed no longer warranted for safe and reliable service.

We thus adopt DRA's proposed reduction relating to PG&E's catch up provision of pole replacements for 2013. We also adopt funding based on recorded expenditures for 2012, which represents $65 million over test year 2011 imputed amounts. By adopting the 2012 recorded expenditures, we provide some recognition of PG&E's efforts toward reducing prior years' backlog of pole replacements. By adopting DRA's proposed reduction for 2013, however, we

assign a share of responsibility to PG&E shareholders, rather than ratepayers, for pre-2011 pole replacement backlogs that were previously funded by ratepayer money.

We disagree with PG&E's argument that it is unfair for its shareholders to absorb a share of cost burden for pole replacements scheduled in the past but not performed. PG&E explains that the funds originally designated for those replacements were used for other work deemed to have higher priority. PG&E claims that DRA's recommendation amounts to a request that PG&E indefinitely spend more than imputed amounts in Electric Operations.

While PG&E claims unfairness to its shareholders, we conclude that it is unfair for ratepayers to fund expenditures for work that PG&E repeatedly deferred based on the timing of GRC funding. We recognize that during 2011, PG&E did spend $29.1 million more than the imputed amount for pole replacements in its 2011 test year, and for 2012 PG&E spent more than $65 million above 2011 imputed amounts. Nonetheless, even with these years of spending above imputed amounts, PG&E still had a backlog of pole replacements compared with prior years' adopted forecasts. Even after accounting for this progress in reducing the backlog, PG&E's capital forecast for 2013 still includes a significant provision to make up for earlier deferrals in spending. These catch-up expenditures represent pole replacements for which ratepayer funding had been authorized but not spent during GRC cycles before 2011.

PG&E is responsible for providing safe and reliable customer service whether or not its overall spending matches funding levels authorized or imputed in rates. PG&E bears the risk that, as a result of spending obligations, the earned rate of return may be less than the authorized return. 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. Based on 2011-2012 spending levels, for example, PG&E demonstrated its capability and willingness to spend more than previously authorized or imputed amounts when deemed necessary to meet service obligations.

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 doesn't automatically justify postponing projects previously deemed warranted for safe and reliable service.

By paying for unanticipated higher-priority expenditures out of ratepayer revenues, rather than out of retained earnings, PG&E's shareholders were protected from the risk that such unanticipated spending would erode profits. To provide this protection to shareholders, PG&E curtailed implementation of the programs which ratepayers had funded. PG&E now seeks similar funding from ratepayers in this subsequent GRC to pay for a program that was curtailed. Utility spending should not be driven simply by the timing of rate relief by deferring pole replacements at levels based on previously adopted forecasts. Accordingly, although we do not expect PG&E to implement its workload in an inflexible manner, we do not believe that ratemaking should provide an incentive to ration projects based upon the timing of rate cases. We thus reduce PG&E's test year revenue requirement to exclude the effects of capital expenditures for deferred maintenance for pole replacements incurred in 2013, as discussed above.

4.8. Vegetation Management

PG&E forecasts $190 million for Vegetation Management expenses in MWC HN for Test Year 2014, an increase of 17.6% over 2011 expenses. The increase is driven mainly by increased environmental regulatory compliance and increased fire risk reduction work to improve public safety. PG&E also requests continuation of its Vegetation Management one-way balancing account.

PG&E's Vegetation Management Program supports public safety, service reliability, and regulatory compliance through management of vegetation growth near electric distribution facilities. PG&E patrols, inspects and maintains clearance on trees required for regulatory compliance and removes trees or other vegetation from around poles that have the potential to cause fires. PG&E annually inspects approximately five million trees along 113,500 miles of high voltage distribution lines.

DRA's estimate for PG&E's Vegetation Management expenses is $164.223 million, or $25.777 million less than PG&E's forecast relating to: (1) Routine Tree work; (2) Environmental Compliance; and (3) Fire Risk Reduction. No one disputes PG&E's forecasts for Vegetation Control, Quality Assurance, or Public Education.

4.8.1. Routine Tree Work

PG&E forecasts $156 million for Routine Tree Work, which is a 3% increase from 2011 levels. DRA forecasts $151.602 million, based on 2011 recorded expense levels for Routine Tree Work, representing a $4.398 million reduction to PG&E's forecast. Spending during 2011 represents the highest recorded annual spending for the period 2007-2011. DRA claims that embedded historical costs can be reallocated and utilized to perform Routine Tree Work. DRA claims PG&E's forecast (1) is not justified compared to historical spending levels;

(2) relies on PG&E's Excel GROWTH function to predict changes in units and unit costs in Routine Tree Work which "routinely overestimates" costs; and (3) lacks adequate documentation of likely increases in contractor costs for Routine Tree Work.

PG&E responds that its forecast is in line with historical levels, reflecting only a 3% increase from 2011 recorded spending to the 2014 forecast which is due primarily to increased unit costs. PG&E contends that simply relying on recorded costs fails to account for divergent trends in costs, as reflected in its 2014 forecast.

Discussion

We conclude that PG&E's forecast for Routine Tree Work has been justified and adopt it. PG&E provided reasonable explanations for the 3% increase in costs for 2014. PG&E provided DRA with evidence to support increasing contractor costs, including labor agreements between PG&E's tree contractors and the International Brotherhood of Electrical Workers (IBEW) that provide for a 2% salary increase in 2011-2012 and a 3% increase in 2014. PG&E offered to have DRA review its contracts with contractors at PG&E's offices. PG&E had the lowest vegetation costs per line mile, compared to other utilities, over a four-year period.

As noted by PG&E, factors driving the increase in unit costs for Routine Tree Work include rising contractor labor costs, lower productivity due to a lower volume of trees worked (more time driving and less time working), and changes in the mix of work performed (i.e., where fewer trees are pruned and tree removals involve larger-diameter trees). PG&E had the lowest vegetation costs per line mile, compared to other utilities, over a four-year period.

Between 2009-2011, PG&E's Excel GROWTH function was able to forecast expenditures within 1% of actual amounts in two years out of three and within 5% in the third year. We find no evidence that PG&E's Excel GROWTH function produces overestimations of routine tree work costs for 2014.

4.8.2. Fire Risk Reduction

DRA claims that ratepayers should not pay the $11.113 million forecast by PG&E for additional Fire Risk Reduction. PG&E's current work to reduce the risk of fires is recorded as Routine Tree Work. DRA claims it is inappropriate to require increased ratepayer funding for activities already embedded in historical expenses.

PG&E responds that its Fire Risk Reduction Work forecast is not embedded in historical amounts. From 2007 through 2013, PG&E's fire risk reduction work mainly consisted of tree branch removal near conductors. PG&E plans to continue this work as part of Routine Tree Work. Beginning in 2014, however, PG&E plans to conduct more intensive inspections focused on the very highest fire risk areas. PG&E has not previously conducted this type of intensive inspection, and it is not included in past fire risk reduction expenses.

Discussion

We conclude that PG&E has justified its forecast for Fire Risk Reduction Work and adopt it. As PG&E notes, the forecast increase is intended to cover more intensive inspections on the highest risk fire areas that is beyond the scope of work covered in embedded funds.

Liberty "found that the Fire Risk Reduction program could potentially reduce wildfire risk. This initiative consists of an aggressive tree inspection and removal program for high fire-risk areas." Liberty says: "[o]ften a hazard tree is not readily apparent without a detailed investigation using sonic or intrusive

bore tests." Liberty states: "the initiatives …generally represent appropriate and effectively managed responses to underlying safety issues." Approval of PG&E's forecast is consistent with Liberty's findings here.

4.8.3. Environmental Compliance

PG&E forecasts $12.591 million for Environmental Compliance expenses, an increase of $12.276 million over 2011 expense. PG&E is increasing the environmental compliance oversight of its contractors as a result of state and federal agencies' increased focus on the potential impacts of Vegetation Management work on sensitive habitats. PG&E will have more elaborate worksite assessments and a greater number of permits to facilitate compliance with environmental regulations as compared to prior years.

DRA's Test Year estimate is $2.361 million for PG&E's Environmental Compliance. DRA normalized half of PG&E's incremental request of $6.138 million. DRA recommends a $10.230 million reduction, claiming PG&E's forecast is excessive based on the level of environmental compliance costs embedded in PG&E's historical costs; and inadequate documentation of the need for additional funding. DRA claims that PG&E will not require $12.276 million in the Test Year to perform these additional activities.

PG&E responds that reliance on historical expenditures fails to account for the new programs for which spending on environmental compliance will be required in 2014 and beyond.

Discussion

We conclude that PG&E has justified its forecast for Environmental Compliance expenses. PG&E's work papers provide explanations of the forecast costs and related assumptions associated with Environmental Compliance work. PG&E forecasts a significant cost increase due to the implementation of the Bay

Area Habitat Conservation Plan, increased scrutiny by environmental agencies, and the need for increased erosion mitigation at Vegetation Control sites. The result will be additional screening, surveying, permitting, monitoring, and mitigation at more tree and pole clearing sites. This is new work that is not embedded in other work categories. In view of these additional cost factors, we find PG&E's forecast for environmental compliance is reasonable and it is adopted.

4.8.4. Balancing Account and Tracking Account

PG&E's 2007 GRC Decision 07-03-044 established the Incremental Inspection and Removal Cost Tracking Account Procedure to record incremental inspection and removal costs PG&E incurs for work required by California Department of Forestry and Fire Protection (CAL FIRE). PG&E has not sought any cost recovery through this procedure, but requests its continuation due to the uncertainty of the costs associated with CAL FIRE's interpretation of utility obligations. No party opposed PG&E's proposal. DRA does not oppose PG&E's request for continuation of its Vegetation Management one-way balancing account.

4.9. New Business and Work at the Request of Others

4.9.1. Processing New Customer Connections (MWC EV)

PG&E forecasts $10.78 million in 2014 for expenses in MWC EV related to processing of new customer connections. DRA proposes a reduction of $1.848 million. The specific elements of dispute between PG&E and DRA are summarized as follows:

	PG&E	DRA
Service Inquiries	$5.5	$4.9

Plug-in Electric Vehicle Service	$1.9	$0.7

The forecast difference for service inquiries relates to different assumptions about how the ratio of new customer connections to applications should be estimated. PG&E uses three years of recorded data. DRA uses only data from 2012 which yields a $600,000 reduction from PG&E's forecast. DRA argues that the use of 2012 data reflects the most recent market conditions. We accept PG&E's methodology and forecast amount, and agree that a three-year period offers a more accurate forecast than does only a single year. As PG&E notes, data from any individual year in the NB/WRO program can be highly variable. The average of three years of data offsets this volatility by using longer term trends.

Parties also differ regarding the forecast for service to Plug-in Electric Vehicles (PEV). PG&E's forecast for this element is $1.9 million which is 533% greater than 2011 recorded costs. PG&E based its 2014 forecast on the estimated number of PEV sales multiplied by the cost per load check. PG&E assumed that the number of PEV applications processed would equal 100% of the number of PEV sales. DRA recommends a reduction of $1.2 million to PG&E's forecast based on the assumption that: (1) PEV sales remain flat from 2012-2014 and (2) the load check application rate resulting from those PEV sales does not change. DRA applies a 40% ratio of PEV applications to sales based on 2011 data. DRA argues that the growth of the PEV market and associated costs remain uncertain. We conclude that DRA's forecast is unreasonably low. DRA's forecasted load check rate on a historical value doesn't reflect the effects of negotiations between PG&E and the DMV to improve PEV sales visibility and to increase the load check rate to 100%.

Discussion

PG&E's assumption of increasing PEV sales is consistent with reported trends. PEV sales in 2012 grew faster than PG&E initially forecast (6,000 recorded sales vs. PG&E's forecast of 3,300). Industry and market indications suggest that PEV sales will continue to grow. The California Plug-In Electric Collaborative, a multi-stakeholder public-private partnership, describes a suite of policies in California that support a growing market for clean PEVs fueled by electricity. Therefore, we adopt PG&E's forecast of $10.78 million for expenses in MWC EV.

4.9.2. Electric Distribution Work Requested by Others (MWC 10)

PG&E forecasts capital expenditures in MWC 10 for installation of electric infrastructure to connect new customers to PG&E's distribution system and to accommodate increased load from existing customers, and relocation of electric distribution and service facilities at the request of a governmental agency or other third party (Exhibit (PG&E-4) at 9-28, lines 3-7). Under its obligation to serve, its tariffs, and franchise agreements with local government, PG&E must perform work necessary to accommodate this increased demand. PG&E's 2012-2014 forecast includes projects such as San Francisco's Transbay Terminal, a central subway in San Francisco, and the high-speed rail (HSR) project in California's central valley (Exhibit (PG&E-4), at 9-30, Table 9-26). The increase over 2011 levels is primarily due to economic recovery forecasts of independent economic forecasting firms. The differences between the PG&E and DRA forecast for MWC 10 for 2012, 2013, and 2014 are as follows:

	PG&E	DRA
2012	$69.7	$110.725

2013	$83.29	$ 81.496
2014	$96.465	$88.818

DRA recommends that PG&E's 2012 recorded costs of $345.314 million be adopted in lieu of its 2012 forecasts for MWCs 10 and 16. PG&E agrees with DRA's recommendation for 2012. DRA's estimate for 2014 is $88.818 million, reducing PG&E's forecast for the HSP project by $5 million on the grounds that the project has been delayed by a half year and might have additional delays. DRA recommends a $5 million reduction for 2014, with the corresponding funding amount moved into 2015, based on the effects of the delays. PG&E does not dispute that the HSR schedule delays have occurred or that they impact the funding forecasts for 2014 and 2015. PG&E simply argues that if DRA is allowed to reduce the 2014 forecast for this one project, PG&E should be allowed to increase the forecast for other projects where the scope has increased or the schedule has accelerated.

DRA also reduces PG&E's 2013 and 2014 forecast amounts for NB-related WRO projects.

Discussion

For 2012, the actual recorded amount for MWC 10 will be adopted. For 2013 and 2014, DRA's forecasted figures for MWC 10 will be adopted. Thus, the adopted MWC 10 figures (in $000s) are: $110,775 (for 2012); $81,496 (for 2013) and $88,818 (for 2014). We conclude that PG&E's 2014 forecast for MWC 10 should be reduced by $5 million to reflect the expected delay in the High Speed Rail schedule. PG&E doesn't dispute that that the High Speed Rail Project has been delayed. We agree in principle that PG&E has the right to offer evidence regarding any additional relevant offsetting project changes in the record that would increase the forecast. In this instance, we find no specific offsetting

adjustments identified that would justify approving offsetting increases in the forecast based on subsequent changes in scope or schedule. Accordingly, we adopt DRA's forecasts for MWC 10 including a reduction of $5 million based on anticipated delays in the High Speed Rail schedule.

4.9.3. Electric Distribution Customer Connections (MWC 16)

PG&E's capital forecast costs for MWC 16 includes residential and non-residential NB work, PEV, and transformer purchases and scrapping. For MWC 10 and 16, PG&E's combined capital forecast is $436 million for 2014 and $355.8 million for 2013, including escalation. The differences between the PG&E and DRA forecast for MWC 16 for 2012, 2013, and 2014 are as follows:

	$ in Millions	
	PG&E	DRA
2012	$210	$234.59
2013	$272.54	$ 260.44
2014	$339.56	$ 317.69

DRA recommends reductions to MWC 16 costs for: (1) Residential Expenditures; (2) PEV Expenditures; and (3) Transformer Purchases.

For residential work, DRA uses the same estimating methodology as does PG&E, but assumes a different ratio of suburban backbone work to subdivision work. DRA accepts PG&E's forecast for increases in units of subdivision service and other residential work, but assumes fewer units of subdivision backbone work in 2013 and 2014 than PG&E forecasts. DRA's recommended subdivision backbone to subdivision service ratio is based on 2012 recorded data. The ratio of subdivision backbone units to subdivision units was lower than forecast in

2012. DRA assumes that this lower ratio will persist, with modest increases, in 2013 and 2014.

PG&E argues that it is unreasonable for DRA to agree with PG&E's forecast for accelerated growth in residential connections, including subdivision service connections, without accepting a corresponding growth in subdivision backbone work that must precede the service connections. PG&E also claims it is inconsistent with the economic recovery projections used in PG&E's forecast. DRA also recommends adoption of PG&E's 2012 recorded costs, which included a higher than forecast number of units of subdivision service and other residential work, without recommending corresponding increases to PG&E's 2013 and 2014 unit forecasts for subdivision service and other residential work.

DRA recommends adoption of PG&E's 2012 recorded costs, which included a higher than forecast number of units of subdivision service and other residential work, without recommending corresponding increases to PG&E's 2013 and 2014 unit forecasts for subdivision service and other residential work.

DRA challenges the PEV sales assumptions and load check application rates calculated as factors in the forecast capital PEV expenditures in MWC 16. DRA assumes that sales of PEVs will remain flat from 2012 through 2014, and assumes there will be no change in the load check application rate as a result of those PEVs sales.

DRA adopted PG&E's forecasting model for transformer purchases which is indexed to several other NB work categories including residential NB (including PEV), non-residential NB, and a grouping of other non-NB related MWCs, but proposes a reduction based on its recommended reductions to those other NB work categories.

Discussion

We adopt capital forecasts for MWC 16 for 2012 of $234.59 million, based on actual costs recorded for 2012. For 2013 and 2014 adopted capital forecasts, we accept DRA's proposed reductions, and adopt forecasts of $260.436 million and $317.369 million, respectively.

For MWC 16 residential work, we accept DRA's subdivision backbone estimate for 2013 and 2014. Although PG&E claims that DRA's assumptions for this element are internally inconsistent, we are persuaded that DRA's differing assumptions can be reconciled. As DRA explains, there is no inherent inconsistency in forecasting increased subdivision connections while at the same time, backbone connections are increasing at a lower rate. During 2012, backbone connections were actually decreasing as subdivision connections were increasing. During the recent economic downturn, many developers stopped building homes after subdivision backbone facilities had already been installed. Now that developers are again beginning to build out subdivisions, there is no corresponding increase in backbone connections, as those are already in place.

We also accept DRA's assumptions regarding PEV sales over the GRC period. We conclude that there is insufficient evidence to indicate that PEV sales will increase significantly over the current GRC cycle, particularly considering the findings in the "Joint IOU Electric Load Research Final Report," filed pursuant to D.11-07-029, as noted by DRA.[41]

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[41] *See* DRA Opening Brief at 147.

We also accept DRA's assumptions regarding transformer purchases which are made consistent with its assumptions for the other MWC 16 cost categories.

4.10. Electric Emergency Recovery

PG&E's Electric Emergency Recovery Program (ERP) is responsible for electric emergency recovery work, consisting primarily of responding to outages. An immediate response is necessary when an outage occurs, a situation is unsafe, or potential for an imminent hazard exists. PG&E forecasts emergency-related expenditures as: normal emergency (Level 1) and major emergency (Levels 2-3).

PG&E forecasts 2014 expense of $113.69 million, including escalation, for ERP in MWC BH (for Level 1) and MWC IF (for Levels 2 – 3). The forecast is $42.7 million less than its 2011 expenses. Forecasts differ from recorded amounts mainly because ERP forecasts are dependent on weather conditions, which are inherently difficult to predict.

PG&E forecasts emergency response capital expenditures in MWC 17 and MWC 95 of $169.383 million for 2013 and $168.9 million for 2014, including escalation. PG&E's 2014 capital forecast is $28.7 million less than recorded expenditures of $202.6 million in 2011. The work in MWC 17 involves routine emergency work that meets capital accounting criteria, such as equipment replacements.

DRA agrees with PG&E's forecast for 2012 to 2014, but reduces 2013 and 2014 by the same amount by which 2012 recorded amount exceeded PG&E's forecast.

PG&E forecasts a three-year total of $352.382 million. DRA agrees with this three-year total amount. Since actual 2012 capital expenditures exceeded the forecast, and because DRA accepts the 2012 actual expenditures, DRA adjusted

its 2013 and 2014 forecast so that DRA's three-year total from 2012-2014 equals PG&E's forecasted three-year total.

For MWC 17, DRA recommends a $9.4 million reduction per year to PG&E's 2014 and 2013 forecasts. PG&E accepts DRA's recommendation for 2012, but not for 2013 and 2014.

Discussion

We adopt PG&E's 2012 recorded expenditures, as agreed to by PG&E and DRA. We adopt PG&E's 2013 and 2014 capital forecast as reasonable. We also adopt PG&E's 2014 expense forecast in MWC BH and IF as reasonable. We are not persuaded by DRA's basis for reducing the 2013 and 2014 forecasts. The total number of Level 1 emergencies in a three-year period is not constant, and the number of emergencies in one year does not correlate with or influence the number of emergencies in other years. Just because PG&E responded to more Level 1 emergencies than forecast in 2012, PG&E will not necessarily respond to fewer Level 1 emergencies than forecast in 2013 and 2014. DRA's recommendation assumes a correlation that has not been shown to exist.

4.10.1. Electric Emergency Recovery Balancing Account

PG&E proposes that a balancing account be approved and implemented to apply to costs incurred in MWC IF and MWC 95, which are the MWCs PG&E uses to record expenditures associated with major emergencies that are not recovered under Catastrophic Event Memorandum Account (CEMA), a mechanism approved in 1991 through Resolution E-3238. The CEMA cost recovery mechanism is separate from the GRC, which includes forecasts for expense and capital expenditures associated with the utility's major emergency

response. PG&E proposes the balancing account to address recovery of the costs of major emergency response that do qualify for recovery under CEMA.

Under PG&E's proposal, if it spends less than its GRC forecasts for major emergency response in MWC IF and 95, the unspent amount would be tracked in the balancing account and returned to customers. If PG&E spends more than forecast for these MWCs, PG&E would seek subsequent cost recovery for the additional amount recorded in the two-way balancing account. PG&E argues that the balancing account mechanism would address its inability to recover all incremental costs reasonably incurred when responding to major and catastrophic events.

DRA opposes PG&E's proposal for a balancing account to cover major emergency expenditures not covered under CEMA, arguing that approval would give PG&E a blank check to engage in spending.

Discussion

We conclude that PG&E's proposal for a balancing account to cover the costs of major emergencies not covered under CEMA is warranted, and approve PG&E's request to implement it. We appreciate the potential for the general proliferation of balancing accounts to reduce the utility's incentive to contain and control escalating costs. In this particular instance, however, we conclude that the specific circumstances involved justify approval of PG&E's proposal for balancing account treatment given the nature of the costs involved.

As PG&E explains, as specified in D.07-07-041, recovery of emergency costs under CEMA is limited to situations where damages have occurred in a county or city in which either the Governor of the State or the President of the United States has declared a disaster or state of emergency. Such declarations are typically associated with significant public infrastructure damage and/or a

high level of response by governmental agencies. However, recent experience has shown that PG&E incurs significant costs responding to a major or catastrophic event where there is not the type of damage to public infrastructure or governmental response that merits a declaration by the Governor or President. Thus, the declaration requirement limits CEMA recovery to those catastrophic events generating a significant response by both the utility and the government. Where a disaster or state of emergency is not officially declared, PG&E is unable to recover under CEMA regardless of how extensively its facilities have been damaged.

We do not believe that authorizing the balancing account creates a "blank check" for spending, as argued by DRA. In a major emergency, PG&E must spend what is required in order to restore service to all customers, and does not have discretion to avoid spending required to address major emergencies not covered under CEMA. The proposed balancing account mechanism ensures that customers will be protected if PG&E's recorded costs are lower than forecast. PG&E will also be able to fund high priority work if recorded costs are higher than forecasted. Cost recovery will be subject to scrutiny to ascertain that the costs incurred were prudent and necessary to respond to a major emergency.

4.11. Distribution System Operations

PG&E forecasts $54.7 million in expense for Distribution System Operations (DSO) in 2014, including escalation. The DSO oversees electric distribution system operations by monitoring 720 distribution substations and 140,000 miles of distribution lines. PG&E's DSO also manages outage restoration, directs system switching, and manages its electric related field customer service work. PG&E also proposes to consolidate thirteen existing DCC into three new locations.

PG&E's DSO forecast includes: (1) $32.7 million for ongoing costs to operate the Control Centers, (2) $20.3 million for customer service work such as transfers of service (MWC DD); (3) $796,000 for technology support (MWC HG); and (4) $0.9 million for software to enable distribution control center consolidation (MWC JV). PG&E's 2014 forecast is $0.5 million higher than 2011 recorded expenses primarily due to software costs in MWC JV.

DRA and TURN recommends reductions to PG&E's forecast for each of these elements is as shown below:

	$ in millions		
Element	**PG&E**	**DRA**	**TURN**
Electric Distribution (MWC BA)	$32.74	$-3.974	$-5.571
Field Service Dispatch Scheduling	$20.328	$-0.515	
Technology Activities (MWC HG)	$0.796	$-0.27	
Technology Expense (MWC JV)	$0.877	$-0.877	$-0.877
Total	$54.741	$-5.393	$-6.448

PG&E's 2014 expense forecast of $32.74 million for MWC BA covers electric distribution grid operations, including switching, circuit reconfiguration, directing outage response, and scheduling customer work. PG&E's Distribution Control Center Consolidation (DCCC) Project involves consolidating 13 DCCs into three interrelated DCCs: one main center and two regional centers. Consolidation will enable greater integration, flexibility, and scalability of operations and will eliminate the need to staff the existing 13 DCCs. Consolidation is expected to reduce operators by 10 in each year from 2013 through 2015 (a savings of $1.87 million per year), reduce Support Personnel by one in 2013 ($150,000 savings) and five additional Support Personnel reductions in 2014 (savings of $750,000), and reduce overtime costs in 2016 by $1.5 million.

PG&E credits ratepayers with the savings in 2013 and 2014, but does not credit ratepayers with the savings from the reduction of Operators and overtime costs in 2015 and 2016.

TURN recommends that the savings that PG&E projects in 2015 and 2016 from staffing reductions and avoided overtime be normalized so that ratepayers realize the benefits during this GRC cycle. Normalizing the savings for 2015 reduces the test year forecast by $1.247 million. Normalizing $1.5 million savings from 2016 for reduced overtime results in $500,000 savings. TURN's total proposed reduction to the 2014 forecast to account for DCC Consolidation Project benefits is $1.747 million.

DRA recommends limiting PG&E's 2014 forecast for MWC BA to $28.769 million. DRA's figure is based on a 2011 recorded cost figure of $33.681 million, reduced for ratepayer savings from staff reductions and overtime attributable to the DCC consolidation.

DRA argues that PG&E is requesting funds for DCC pre-consolidation that it received in the 2011 GRC ($3.785 million in 2010 and $0.709 million in 2011). DRA recommends rejection of PG&E's entire forecast of $877,000 for software development for DCC consolidation. DRA states that the 2011 GRC authorized funding contained embedded for PG&E's proposed software labor (employee and contract labor) costs for the development and testing of its electronic wall mapping system. DRA states that PG&E had 2012 and 2013 to develop and test its electronic wall mapping system before the test year. DRA argues that ratepayers should not bear further rate increases to pay for activities already embedded in historical costs.

TURN recommends reductions incremental to DRA's adjustments. TURN recommends an additional reduction of $1.597 million for a test year forecast of

$27.132 million. If the Commission does not adopt DRA's recommendation, TURN still recommends a reduction of $1.597 million to account for the 2015 and 2016 savings from the DCC Project, resulting in a test year forecast of $31.146 million.

PG&E also forecasts capital costs of $33.8 million, including escalation, for one main DCC and two regional DCCs. No party opposed, and DRA specifically supported, PG&E's MWC 63 forecasts of $33.849 million in 2014 and $34.971 million in 2013, the largest expenditures for the DCCC project.

For PG&E's forecast in MWC 2F, DRA recommends a $256,000 reduction for 2014 and $1.8 million for 2013. TURN recommends overall reductions of $127,000 to PG&E's 2014 forecast. DRA recommends that PG&E be funded for 2012 at the level of its recorded costs for MWC 2F and MWC 63 rather that its forecast costs. PG&E agrees with DRA's recommendation for 2012.

PG&E's forecast for MWC 2F is $904,000 in 2014 and $6.373 million in 2013. DRA recommends the2013 and 2014 forecasts for MWC 2F be reduced by: (1) 20% to eliminate a project contingency factor in PG&E's forecast; and (2) a further 14% to account for alleged flaws in PG&E's Concept Estimating Tool, which was used to develop the forecast. DRA's recommendations would result in reductions of $256,000 in 2014 and $1.806 million in 2013.

TURN agrees with DRA's Concept Estimating Tool based reductions. TURN's recommendation reduces PG&E's 2014 forecast by $127,000 and PG&E's 2013 forecast by $0.9 million.

We adopt PG&E's forecast of $20.3 million in MWC DD for Field Service Dispatch Scheduling subject to disposition of labor rates and escalation addressed in a later section of this decision. PG&E's forecast is based on its 2011 recorded expenses but also includes an additional $115,000 for labor rate

increases between 2011 and 2012 and $418,000 for escalation. DRA's reduction of $515,000 is based only on 2011 historical spending without adjustment for subsequent changes through 2014.

We adopt PG&E's forecast of $32.743 million of MWC BA. Although DRA claims PG&E failed to reflect cost savings for reduced labor and associated overtime in the forecast, PG&E argues that these cost savings will be reflected implicitly in the attrition mechanism for 2015 and 2016, and shouldn't also be counted through a normalization adjustment for 2014. Thus, we find no basis to reduce PG&E's 2014 forecast for these savings that relate to the attrition years.

PG&E conducted DCC center "pre-consolidation" work during 2010-2012 even though these control centers will be phased out after the project is complete. PG&E explains that conducting this work was necessary for the safe and reliable monitoring and control of PG&E's electrical distribution grid.

PG&E does not dispute that it received funding for the DCC pre-consolidation in the 2011 GRC, but argues that its decision to postpone the DCC consolidation program one year was prudent because it allowed time to develop a more cost-effective consolidation program. When PG&E recognized a more cost-effective solution to DCC consolidation might be possible, it put its plans on hold for a year to evaluate its options. This ultimately resulted in a less costly project. Because it was temporarily not pursuing DCC consolidation, PG&E redirected the DCC consolidation funding to other work. PG&E argues that the one-year postponement thus should not result in rejection of the project.

As discussed previously, we do not believe ratepayers should fund deferred maintenance based merely on the claim that PG&E diverted authorized funds for other unanticipated work deemed by PG&E to be of higher priority at the time. In this instance, however, we conclude that PG&E has adequately

explained its rationale for deferring spending on the DCC consolidation project with the result that ratepayer interests benefitted resulting in a more cost-effective solution. Given the benefits to ratepayers from the deferral, we will permit PG&E to recover prospective funding to go forward with the DCC consolidation.

Thus, we also approve PG&E's forecast of $877,000 for MWC JV, which are for labor implementation costs related to implementing the software for the DCCC project.

We also approve PG&E's forecast of $2.8 million in 2012, $35 million in 2013 and $33.8 million in 2014 for capital costs of the DCCC project under MWC 63D, for the reasons stated above regarding the DCCC project.

PG&E's 2014 forecast of $796,000 (including escalation) for MWC HG is for technology specialists and supervisors to provide end-user support for critical applications, including minor projects and enhancements. Personnel provide troubleshooting and issue resolution of these managed applications and ensure that they are operating effectively. DRA recommends a $27,000 reduction from PG&E's forecast based on PG&E's 2012 recorded adjusted expenses with no escalation. We adopt DRA's adjustment.

Additionally, PG&E forecasts $1.8 million in 2012, $6.4 million in 2013, and $0.9 million in 2014 in MWC 2F for IT related capital costs for Distribution System Operations Activities. We approve PG&E's actual costs of $1.808 million in 2012. But because PG&E uses the Concept Estimating tool in developing the 2013 and 2014 forecast, we will reduce PG&E's 2013 and 2014 forecast by 14%, as per DRA's recommendation. Therefore, we approve $5.481 million in 2013, and $777,000 in 2014.

4.12. Electric Distribution Lines and Equipment Capacity

Through its Capacity program, PG&E expands bank capacity at substations and transformer capacity outside of substations to meet customer demand growth, and addresses equipment overloads and voltage complaints.

PG&E forecasts capacity costs in MWC 46 (Substation Capacity) and MWC 06 (Distribution Line and Equipment Capacity) for 2013 of $143.8 million and for 2014 of $182.8 million. The forecast is $29.5 million higher than 2011 recorded costs. Increases in forecast work are to address circuits with a large number of customers, overloaded transformers, completion of mainline loops to comply with design standards, and substation transformer emergency capacity issues.

DRA recommends reductions of $6.853 million in 2014 and $969,000 in 2013 for: Substation Capacity Projects Greater Than $1 Million in MWC 46; Overloaded Transformers in MWC 06; and Complete Mainline Loops in MWC 06. DRA also recommends that PG&E be funded for 2012 at recorded amounts, and PG&E agrees. No party disputes PG&E's forecasts for six categories of work in MWC 06.

DRA recommends a $1 million reduction to PG&E's forecast for Substation Capacity Projects Greater Than $1 Million. This work consists of upgrading existing transformer banks or installing additional banks at existing substations, and installing new transformer banks and other equipment at new substations. DRA recommends no funding for one of PG&E's substation capacity projects, the Gosford Substation Project. DRA argues that the Project has not yet entered the Permit to Construct (PTC) process, which is often lengthy, and that construction is unlikely to begin until after 2014. PG&E responds that the $1 million forecast

for this project is not for construction, but for preconstruction expenses including the PTC process.

Merced Irrigation District and Modesto Irrigation District (collectively, the MIDs) argue that PG&E should provide project cost information by Distribution Planning Area (DPA) and the Commission should evaluate the proposed revenue requirement for projects in overlapping DPAs to determine rates in the next phase of the GRC.

Discussion

We adopt PG&E's forecast for electric distribution substations in MWC 46, and conclude that PGE reasonably justifies the forecast. We also adopt the MID proposal for PG&E to provide project cost data by DPA in the next GRC. We thus direct PG&E to provide such information so that we may evaluate revenue requirements in overlapping DPAs.

4.12.1.1. Overloaded Transformers

PG&E's Overloaded Overhead and Underground Line Transformers subprogram in MWC 06 corrects capacity-deficient distribution line transformers by replacing them with larger transformers or adding transformers to existing ones and transferring load. DRA claims that because PG&E forecast fewer transformer replacements in 2012 than it performed in 2011, and transformer replacement is relatively low priority work, PG&E's forecast increased rate of replacement is excessive. For this subprogram in MWC 06, DRA recommends a $0.9 million reduction in 2013 and a $1.4 million reduction in 2014. DRA recommends that funding be limited to 300 transformers per year in 2013 and 2014. DRA does not question the importance of transformer replacement work, only the pace at which PG&E plans to complete it.

PG&E acknowledges that replacement of overloaded transformers is not an emergency, but asserts that it is important work that needs to be done. PG&E claims that based on the large number of extant overloaded transformers (more than 11,000), replacement should be accelerated going forward, to support reliability.

Discussion

We conclude that PG&E's forecast pace of replacement is reasonable and we adopt PG&E's forecast. Because PG&E forecast fewer transformer replacements in 2012 than it replaced in 2011, DRA argues that transformer replacement is relatively low priority work. DRA argues that PG&E has not justified its proposed rate of replacement and instead recommends 300 transformers per year in 2013 and 2014. PG&E replaced 259 transformers in 2011, and forecast replacing 176 in 2012. PG&E has recently identified 11,175 distribution transformers loaded to greater than 100% using SmartMeter™ data. Thus, we conclude that PG&E's forecast replacement of 375 transformers in 2013, and 417 transformers in 2014 is reasonable.

4.12.1.1.1. Mainline Loop Program

PG&E's Mainline Loop program seeks to complete 99 projects to bring existing radial lines up to the mainline loop design standard so that customers on those lines can maintain power when the circuit is broken.

For complete mainline loops, DRA accepts PG&E's forecast for 2013, but recommends a $4.2 million reduction from PG&E's forecast for 2014. DRA does not question the importance of the mainline loops work, only the pace at which to complete it. DRA claims that PG&E has not provided justification for a six-fold increase in the number of projects forecast over historical amounts, or demonstrated the urgency of completing all projects by 2016. DRA recommends

that only 32 mainline loop projects be undertaken between 2014 and 2016, divided evenly among those years.

Discussion

We adopt PG&E's forecast. We conclude that PG&E's forecast to complete 99 outstanding mainline projects by 2016 is reasonable given the need to comply with design standards and to provide better reliability and operational flexibility during maintenance and emergency situations. The radial lines identified for the mainline projects serve over 56,000 customer accounts that are at risk and customers could face long duration power outages in the event of a cable or equipment failure, third-party dig in, vehicle accident, or routine scheduled maintenance.

4.13. Substation Asset Strategy (SAS)

PG&E's (SAS) work is focused on operation, maintenance, installation and replacement of key substation infrastructure. Distribution substations transform high-voltage electricity from PG&E's transmission system to lower-voltage electricity for delivery to customers. Forecast work includes replacing obsolete and failed equipment, maintaining equipment reliability and effective operation.

4.13.1. SAS Expense Forecast

PG&E's 2014 SAS expense forecast for MWC GC is $38.6 million, including escalation. This forecast is approximately $5.5 million over 2011 recorded costs for MWC GC, and directly related to increased corrective work. DRA recommends $3.3 million of reductions consisting of: (1) $2.327 million for the Corrective Maintenance; (2) $0.853 for Substation Support Activities; and (2) $0.117 for escalation. DRA agrees with PG&E's forecast for the Preventive Maintenance subprogram, though the parties differ about how escalation should be calculated.

PG&E relied on 2011 recorded unit costs for its 2014 forecast since 2011 costs represented the most recent costs available. DRA calculated unit costs based on a four-year average from 2009-2012, which DRA claims better accounts for year-to-year fluctuations in costs of maintenance notifications.

Discussion

We conclude that PG&E's expense forecast for MWC GC is reasonable and adopt it. The forecast is based on unit costs from 2011, when all corrective maintenance costs were appropriately recorded in the same subprogram. PG&E did not begin to separately track SAS corrective maintenance costs until 2009. In 2009 and 2010, only a portion of its costs for corrective maintenance were included in this separate tracking mechanism and reflected in recorded costs for this subprogram. As a result, PG&E's recorded unit costs for corrective maintenance in 2009 and 2010 are less than the actual amounts spent on SAS corrective maintenance. Thus, we decline to adopt DRA's proposed reduction.

DRA recommends an $853,000 reduction to PG&E's 2014 forecast for System Funded Projects by using a three-year average (2009-2011) of recorded costs. DRA's reduction is based primarily on disagreement with PG&E's forecast of $500,000 for transformer relocation and $400,000 to support emergent programmatic substation reliability improvement initiatives.

DRA claims that transformer relocation is not necessary because PG&E relocated only one transformer in 2009-2011. We conclude that PG&E's historical level of work is not indicative of its future plans. We accept PG&E's explanation that its forecast of relocations is necessary to effectively manage its current inventory of surplus transformers. Maintaining a large inventory of surplus transformers in storage is not economical as their condition may deteriorate over time. A better use of the transformers is to install them where it is cost-effective

to use them rather than purchasing new units. DRA claims that PG&E did not provide sufficient documentation or analysis to support its request of $400,000 for Emergent Work. PG&E claims that emergent work that program details and exact cost estimates are not available because the final scope of the emergent program has not yet been defined.

Liberty found that PG&E's SAS programs are effectively managed, and have no unaddressed safety risks.

4.13.2. SAS Capital Expenditures

Four MWCs cover SAS capital costs. MWC 48 relates to the replacement of substation equipment such as switchgears, circuit breakers and batteries and other miscellaneous substation infrastructure. MWC 54 relates to the proactive replacement of substation transformers. MWC 58 relates to capital costs of substation safety including seismic, fire protection, and security work. MWC 59 relates to the emergency replacement of substation equipment. PG&E's combined 2014 capital forecast for these four MWCs is $175.012 million, including escalation.

DRA recommends 2014 capital funding reductions of $33.4 million from PG&E's forecast. The primary reductions are for switchgear projects, transformer replacement, and emergency equipment replacement.

Substation switchgear equipment includes electrical disconnect switches, bus conductors and circuit breakers used to control power flow, isolate problems, and protect electrical equipment. The switchgear targeted for replacement is on average 50 years old, and shows signs of deterioration. This switchgear equipment needs to be replaced to maintain long-term safety and service reliability.

DRA's recommendation for 2014 is based on PG&E's 2013 forecast, and would reduce PG&E forecast number of switchgear projects from 13 to 10. DRA claims that PG&E's plan to work on 13 projects simultaneously is overly ambitious, especially given that PG&E forecast 14 switchgear projects in the 2011 GRC but only completed two.

Discussion

We conclude that PG&E's forecast for SAS capital expenditures is appropriate and is adopted. We appreciate DRA's concern that the scope of the project appears overly ambitious. We agree with PG&E, however, that beginning work on these three additional projects in 2014 is appropriate because it takes several years to develop and execute a switchgear project. PG&E's forecast will allow a balance of switchgear projects in various phases of the project cycle so that PG&E can better plan and manage resources to efficiently execute switchgear projects going forward. PG&E decided to reschedule most of the switchgear projects originally forecast in the 2011 GRC until it had completed the Mission substation project in order to leverage lessons learned from that project. The project work scheduled for 2014 to 2015 reflects those lessons learned.

4.14. Electric Engineering – Distribution Planning, Operations and Power Quality

PG&E forecasts $23.72 million in 2014 expense for MWC FZ which contains four MATs. The Engineering Program primarily consists of electric distribution engineers who support capital expenditure programs, electric distribution operating functions, and power quality investigations. The majority of engineers focus on performing engineering analysis to support capital project needs for capacity, reliability and operations, responding to customer requests

requiring engineering expertise, and providing protective device settings and voltage control device settings for new equipment installations. PG&E's 2014 forecast is $4.1 million more than its 2011 recorded costs, due to an expected increase in program work. DRA recommends a $2.295 million reduction, with differences itemized as follows:

	($000s)	
Description	**PG&E Forecast**	**DRA Proposed Reductions**
Distribution Engineering	$18,743	-$650
Voltage Complaint Investigation	$1,425	-$204
Transformer Report Manage	$200	-$192
Field Work	$1,515	-$1,178
Escalation	$632	-$71
Non-Disputed	$1,207	_____
Total	$23,722	-$2,295

PG&E's 2014 forecast for Distribution Engineering (MAT FZA) is $18.743 million. DRA recommends a $650,000 reduction, including $450,000 for wires down investigations and $200,000 for emergent work. DRA claims PG&E did not provide sufficient documentation, calculations or analyses to support its forecast and that embedded funds can be allocated to the wires down investigation process.

Discussion

We conclude that PG&E has justified its $18.743 million forecast for MAT FZA. The forecast expense is warranted to cover PG&E's initiative to proactively identify problems and mitigate safety risks relating to conductor, connectors, and/or design issues that may contribute to downed wires. We

conclude that existing embedded funds for wires down corrective maintenance programs are different from the new investigations being proposed here, and thus, it is not reasonable to require PG&E to divert embedded funds to cover this new initiative.

We conclude that PG&E has justified its$1.425 million forecast for 2014 for engineering investigation of customers' voltage complaints and anomalous voltage conditions detected by SmartMeter™ technology. DRA proposes a $204,000 reduction given PG&E's lower-than-forecast spending on this activity during 2012. PG&E's reduced spending in 2012 was due to conducting only a pilot program initially prior to rolling out the program on a system-wide basis. Accordingly, PG&E's 2014 forecast reflects the full program roll-out. We adopt PG&E's $1.425 million forecast.

We also adopt PG&E's $200,000 forecast for engineering investigations of potentially overloaded and idle distribution line transformers. We decline to adopt DRA's proposed reduction of $192,000. DRA infers that because PG&E performed no proactive transformer reviews based on SmartMeter™ data during 2012, no funds should be authorized for this activity for 2014. PG&E explains, however, that below-forecast spending on transformer reviews during 2012 was because of fewer overloaded transformer replacements. PG&E forecasts $5 million in MWC 06 to replace overloaded transformers in 2014. Thus, additional 2014 funding for investigations of transformers will be needed to decide which overloaded transformers need to be replaced.

We also adopt PG&E $1.515 million forecast for field work relating to phase balancing and fuse replacements to address potential system overloads. DRA's proposed reduction of $1.178 million is based on the significantly lower level of activity in 2011 relating to this program, as compared to 2014. PG&E has

documented the need for a significant increase in the number of phase balancing projects relative to historic activity and identified where the additional work will be done in 2014.

4.15. Electric Distribution Reliability

PG&E Electric Distribution Reliability Program addresses overall reliability performance, and includes costs for electronic control equipment installation or upgrade, replacement of deteriorated sections of overhead conductors. Other significant components are the Targeted Circuit Initiative and installations of FLISR automated systems which use "self healing" circuit technology to reduce the outage duration of most customers to less than five minutes. FLISR systems use a combination of SCADA switches, telecommunications equipment and software running on a central computer to automatically limit the scope of outage to the zone where the outage originated. The methodology used to determine the costs was developed from the large portfolio of work associated with the Cornerstone Project. PG&E forecasts capital expenditures in MWC 08 and 49 PG&E forecasts capital expenditures in MWC 08 and 49 of $148.6 million for 2012, $193 million for 2013, $172 million for 2014, $174.5 million in 2015, and $179.2 million for 2016. PG&E's 2014 forecast is 9.3% higher than 2011 recorded amounts.

DRA recommends a reduction of $54.485 million to PG&E's 2014 forecast for MWCs 08 and MWC 49. TURN recommends a reduction of $53.1 million for 2014. CCUE believes PG&E should perform more work than forecast in MWCs 08 and 49.

The work in MWC 08 includes: (i) Base Reliability; (ii) Overhead Conductor Replacement; and (iii) Line Recloser Revolving Stock. The work in MWC 49 includes: (i) FLISR Installations; (ii) Targeted Circuit Initiative;

(iii) Recloser Control Upgrades; (iv) Overhead Protection; (v) Underground Protection; and (vi) Fault Indicators, Overhead and Underground.

4.15.1. Overhead Conductor Replacement

The Electric Reliability Overhead Conductor Replacement in MWC 08 is one of two coordinated programs to replaced deteriorated overhead conductor. PG&E forecasts $32.5 million in 2014 for MWC 08 to replace 325,000 linear feet (approximately 62 miles) of deteriorated conductor per year (less than 1% of the 70,000 miles of small conductor in PG&E's system).

DRA recommends a $16.5 million reduction from PG&E's forecast based on replacing 160,000 feet of conductor per year, reduced from PG&E's forecast of 325,000 feet per year, which is four times recorded levels. DRA's forecast for 2014 is a 100% increase over PG&E's request for the prior year and nearly double the previously highest recorded amount replaced (in 2008). DRA argues that PG&E's forecasted increased pace of replacements is excessive relative to historical levels.

Reliability improvements are a secondary goal of the program. Safety and the replacement of aging infrastructure are the primary goals. All of PG&E's overhead conductor replacement programs taken together replace much less than 1% of the conductor on PG&E's system per year, and conductor is constantly deteriorating. Thus, it is unlikely that the reliability benefits of replacement have changed significantly since 2009.

Discussion

We conclude that PG&E has justified its forecast for conductor replacements. The program will mitigate the public and system safety risks of "wire down" events and help address what Liberty described as a "widespread

safety concern." Proactively replacing deteriorated conductor reduces outages. Liberty noted:

> The longer a utility takes to address aging infrastructure, the more reliability and safety issues emerge, and the more difficult it becomes to support initiatives in a manner that maintains a sustainable rate trajectory.

Liberty questions PG&E's forecast unit cost for this program because it was higher than the unit cost for PG&E's other overhead conductor program (Infrared Conductor Replacement) and because it appeared to be based in part on projects where engineers installed upgraded conductor rather than replacing conductors with equivalent capacity wires Exh. 168 (Liberty) at 144. We accept PG&E's explanation that the higher forecast unit cost for this program, as originally envisioned, was directed toward larger scope projects that would sometimes require increased wire size (due to anticipated load growth) and replacement of supporting infrastructure such as poles and framing. By contrast, the Infrared Conductor Replacement program focused on replacing single spans of conductor with equivalent wires sizes on existing poles. PG&E's current plan for the program takes a more holistic approach, but the mix of work in the combined programs - and the funds necessary to perform that work - will be the same as forecast. Exh. 55.

We decline to adopt DRA's proposed reductions for this program. We recognize that PG&E's forecasted rate of replacement is considerably higher than historic levels, but it is still modest compared to the large amount of overhead conductor PG&E eventually will have to replace. Postponing replacements until future GRCs will exacerbate the problem as more conductor deteriorates and other types of aging infrastructure compete for funding. The Value of Service (VOS) Study of reliability benefits commissioned by PG&E determined that this

program has a benefit-to-cost ratio of approximately 2 (not including safety benefits). We thus conclude that it is in ratepayers' interests to fund this program at the level proposed by PG&E.

4.15.2. Line Reclosers (MWC 08)

PG&E also forecasts $24.42 million in MWC 08 for line recloser revolving stock. Each new FLISR circuit requires, on average, the installation of three line reclosers. Based on a 100-unit reduction to PG&E's 2014 forecast for FLISR installations, DRA also recommends a corresponding 300-unit decrease in PG&E's line recloser forecast, amounting to a $6.6 million reduction to PG&E's forecast of $24.420 million.

For 2014, DRA accepts PG&E's unit cost, but forecasts fewer miles of overhead conductor replaced (at 52, line 25) and fewer line reclosers purchased (in conjunction with DRA's recommended reduction for FLISR installations, each of which requires several line reclosers.

We approve funding for line reclosure revolving stock, but with approximately 25% reduction to be consistent with our 25% reduction of funding for FLISR/Feeder automation. In addition, given the other large funding increases at issue in this GRC, we conclude that burdening ratepayers with full funding of this project has not been sufficiently justified.

4.15.3. Distribution Circuit/Zone Reliability – FLISR Installations (MWC 49)

PG&E forecasts $61.923 million, $61.719 million, and $103.84 million for MWC 49 capital expenditures for 2012, 2013, and 2014, respectively. DRA agrees with PG&E for 2012 and 2013, except for a $19,000 difference for labor escalation. DRA disagrees with PG&E's 2014 forecast relating to the estimated number of FLISR installations.

PG&E forecasts 2014 capital costs of $60 million in MWC 49 for FLSIR systems based on deployment of FLISR technology on 200 circuits per year during 2014 to 2016, and targeting poor performing urban and suburban circuits. The technology is the same as that used in PG&E's Cornerstone Project, as addressed in D.10-06-048, and will build on the same infrastructure and technology to support that project.

DRA proposes reducing PG&E's FLISR forecast for 2014 to $30.0 million, funding FLISR installations only on 100 circuits per year, based on the average annual number of installations approved in D.10-06-048 (the Cornerstone proceeding). DRA uses a lower labor escalation rate (2.61% versus PG&E's 2.75%) which accounts for a $0.8 million reduction in 2014. DRA's 2014 forecast is twice as high as PG&E's highest previously recorded replacement amount (in 2008) and twice as high as PG&E proposes for 2013. DRA believes that PG&E would not have proposed a 2013 budget that failed to reflect PG&E's stated emphasis on safety and reliability. Thus, DRA believes its 2014 forecast, while a more moderate increase, but still reflects due emphasis on safety and reliability.

The 400 FLISR installations funded in D.10-06-048 (Cornerstone proceeding) were to be on PG&E's worst performing circuits, which is "low hanging fruit" in terms of available reliability gains. PG&E will thus be spending more money to achieve fewer reliability gains with this new round of FLISR installations. Because PG&E's forecast covers the next groups of poor performing urban and suburban circuits, PG&E argues that there are still significant reliability benefits to be gained from installing FLISR on these additional circuits.

As noted in D.10-06-048, for this GRC, PG&E was to perform and present a VOS study to help determine to what extent, if any, electric distribution

reliability should be improved to satisfy customer needs. In developing reliability improvement projects, PG&E was to demonstrate if there is a need for such programs or projects, and if so, whether the program or project represents the optimal solution considering alternatives and cost-effectiveness in the identification and prioritization processes. Subsequent to D.10-06-049, PG&E conducted a VOS of the reliability benefits of certain programs, which showed FLISR installations to have a favorable benefit-to-cost ratio. PG&E argues that this high benefit-to-cost ratio justifies an increased rate of FLISR installation. DRA questions the assumptions underlying PG&E's benefit-to-cost ratio.

TURN agrees with DRA's adjustments, but recommends that PG&E use the adopted lump sum to derive the most reliability it can for that amount of money with a more comprehensive approach to reliability spending.

Greenlining recommends that PG&E make an increased commitment to Limited English Proficient (LEP) speakers in its reliability programs. PG&E discusses its commitment to LEP speakers, and Greenlining's recommendations, in Exhibit 57 (PG&E-20), Section G, at 6-23 to 6-24.

CCUE believes PG&E should perform more work than it has forecast in several subprograms in MWCs 08 and 49. In general, CCUE believes additional work is justified by the programs' high benefit-to-cost ratio in PG&E's VOS study.

TURN reduces PG&E's forecast for these accounts by $53.1 million and proposes that PG&E approach reliability spending in a comprehensive manner and prioritize its spending to achieve the most reliability it can for that amount.

PG&E argues that it should not be required to prioritize this spending, despite significant reliability-related spending scattered throughout its various accounts. PG&E fails to justify why it should not be required to address electric

distribution reliability matters in an integrated fashion in order to allow prioritization of the programs in the context of reliability and with regard to the overall revenue requirement.

Discussion

We conclude that PG&E has justified the need for FLISR installations, but we will reduce 2014 capital funding by approximately 25%, for a 2014 adoption of $45 million, due to the fact that PG&E failed to justify why it could not address electric reliability matters in an integrated fashion. We previously provided the following guidance as to how PG&E should address electric distribution reliability in future Cornerstone proceedings:

> With respect to future proceedings, PG&E should address all electric distribution reliability matters in an integrated fashion through the GRC process. This will allow consideration and prioritization of all types of reliability programs and projects (existing, expanded or new), not only in the context of reliability but in the context of the overall base revenue requirement. [42]

We thus directed PG&E to consider reliability spending in the context of overall base revenue requirements. Given the large increase proposed for 2014, PG&E's reliability-related funding should be moderated. With reliability programs spread throughout PG&E's showing without comprehensive consideration and analysis of total spending and benefits, PG&E is not assessing the projects holistically or with an attempt at prioritization.

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[42] D.10-06-048 at 19. Emphasis added.

As noted by TURN,[43] PG&E's test year spending forecast related to electric distribution reliability includes the Smart Grid Pilot Program. TURN notes, however, that PG&E is not integrating the results of its Smart Grid Pilot Project activities into its $525.7 million (in 2014-2016) reliability spending forecast. The Smart Grid Pilot Results will not be available until PG&E completes its pilot in 2016. Instead of speeding up reliability-related spending, TURN thus argues that PG&E should slow down until the Smart Grid Pilot Project results are available and the technologies from the pilot program can be integrated in a comprehensive and cost-efficient manner. TURN thus recommends combining PG&E's 2014 forecasts for Base Reliability (MWC 08) and Circuit/Zone Reliability (MWC 49) for ratemaking purposes and making a high-level, downward adjustment to the combined forecast.

We are persuaded that PG&E's VOS analysis provides justification to support the project but believe reduced funding for FSLIR installations by approximately 25% will sufficiently allow PG&E to move forward with the project. This should allow PG&E to complete approximately 150 installations per year for 2014-2016, or approximately 450 installations over three years. This is a little less than the pace of work that PG&E forecasts for 2012 and 2013, the last two years of the Cornerstone program, but the total installations over three years would be slightly more.

PG&E's VOS study shows that the FLISR program has value to PG&E's customers, as measured by a benefit-to-cost ratio of 31.1. Both System Average

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[43] Exh. 137, TURN Testimony of Garrick F. Jones.

Interruption Duration Index and System Average Interruption Frequency Index are significantly improved on circuits with this technology.

As shown in PG&E's workpapers (WP 15-17), the benefit-to-cost ratio used by PG&E is based on a 2009 study. The benefits in that study would be higher than currently available benefits. PG&E acknowledges that the incremental reliability gains from FLISR installations it is forecasting are not likely to be as large as gains from the Cornerstone FLISR installations, but believes any difference between the past and future reliability gains will be modest. Even if incremental reliability benefits were only 50% of past levels (taking line reclosers costs into account), the FLISR benefit-to-cost ratio would still be more than 12. The FLISR installations would still be one of PG&E's most cost-effective reliability measures. Given these considerations, we conclude that this program should be funded, but adjusted by a 25% reduction to PG&E's forecast of FLISR installations based on the considerations noted above regarding integration of the technologies developed from the Smart Grid Pilot Project.

4.16. Underground Asset Management

PG&E's underground primary distribution cable covers approximately 27,900 circuit miles. PG&E forecasts $72.0 million in 2012, $68.9 million in 2013, and $140.1 million in 2014 for MWC 56, which primarily consists of replacing underground cables to address aging infrastructure and improve safety.

DRA accepts PG&E's 2012 recorded expenditures and 2013 forecast (with a slight adjustment in escalation), but recommends a lower 2014 forecast of $89.8 million.

4.16.1. Network Cable Replacement

PG&E forecasts $21 million for its Network Cable Replacement program consisting of 12kW primary circuits and corresponding low-voltage secondary

grids that comprise the majority of the network system. PG&E spent $798,000 on this program in 2011 and forecasts capital spending of $7.0 million and $6.0 million in 2012 and 2013, respectively. PG&E seeks to dramatically ramp the program up to $21 million in 2014 and $28 million in 2015 and 2016 for a total cost of $77 million. PG&E argues that it needs to replace primary and secondary network cables because the cables have reached the end of their useful lives and replacing the cables will improve safety and reduce the risk of fires and explosions in downtown San Francisco and Oakland.

TURN argues that PG&E has failed to adequately justify its request for $77 million over the next three years for proactive network cable replacements. TURN recommends the Commission reduce PG&E's request by $14 million for a test year forecast of $7 million, which is equal to PG&E's 2012 forecast expenditures.

Discussion

We adopt PG&E's 2014 forecast for Network Cable Replacement of $21 million. We recognize that PG&E's forecast reflects a significant increase over past years, but conclude that the safety risk that is mitigated warrants the increased expenditures. While TURN has challenged PG&E's support for claimed spending increases, we conclude that PG&E has provided sufficient information to support a conclusion that network cable failures can lead to explosions and manhole cover displacements. Cable failures can also cause major service interruptions in large parts of San Francisco. Many of the cables involved are between 50 and 90 years old, and at the end of their service life. Liberty states that "consistent failure incidents make addressing the risk an

important safety initiative."[44] Swiveloc manhole covers help to mitigate the safety risks, but do not eliminate them. Given the mitigation of the safety and reliability risks involved in this initiative, we are persuaded that PG&E's 2014 forecast warrants adoption.

4.16.2. TGRAM/TGRAL Switch Replacement

PG&E proposes to proactively replace 140 Transfer Ground Rocker Arm Main/Transfer Ground Rocker Arm Line (TGRAM/TGRAL) switches a year between 2014 and 2016 (420 total), through its TGRAM/TGRAL Switch Replacement Program. PG&E will have spent $77.192 million between 2010 and 2013 according to its forecast. PG&E forecasts test year spending of $39.200 million, and a 2014-2016 program cost of $117.6 million to complete the remaining units. Overall the proactive TGRAM/TGRAL Switch Replacement program will cost $194.881 million. PG&E's forecast is based on a list of cable and switch replacement projects, with cost estimates based on data from similar projects.

PG&E installed over 1,000 of these switches across its system starting in the 1940s. In June 2009, a cable failure in a manhole located in San Francisco escalated into a fire that burned through a TGRAM/TGRAL switch's case, igniting the oil in the switch and prolonging the fire. Shortly thereafter, PG&E determined that the TGRAM/TGRAL switches should be retired across the entire distribution system through a dedicated, multi-year program to improve public and employee safety. PG&E contemplates by 2016, replacing all remaining TGRAM/TGRAL oil-filled switches within its system, which are

[44] Exh. 168, Liberty at 145.

deployed primarily in densely populated urban areas, and provide underground cable sectionalizing capability for paper-insulated lead covered cable systems.

DRA recommends removing TGRAM/TGRAL switches at a rate of 100 units per year rather than 140 per year as forecast by PG&E. DRA argues that extending the program for a year is reasonable noting PG&E has already taken steps to adequately mitigate the risk posed by the switches. DRA recommends that, instead of replacing the remaining 420 switches over three years, the replacements be spread over four years for a cost of $28 million instead of PG&E's forecast of $39.2 million.

PG&E claims that DRA's proposed slowing of the pace of replacement would be arbitrary and contribute to a cascade of delays to efforts to address aging infrastructure.

TURN claims that PG&E failed to quantify the reliability benefits of replacing the TGRAM/TGRAL switches, and has not justified the requested level of spending or rate of replacement. TURN recommends limiting the program from 2014 onward to 33 replacements per year for a total of 99 units. TURN recommends denying capital expenditures above this level for proactive TGRAM/TGRAL switch replacements unless and until PG&E shows it is reasonable to proactively replace the switches of least concern (i.e., switches deemed to be Priority 8). TURN's recommendation results in a 2014 capital spending forecast of $9.124 million, or a $30.076 million reduction to PG&E's test year forecast.

Discussion

We approve PG&E's requested funding to remove and to proactively replace TGRAM/TGRAL switches for 2014. We find that these switches create safety risk, and completing their removal on the schedule proposed by PG&E is

an appropriate measure to promote safety. We base our funding approval primarily on considerations of safety, operability, and obsolete infrastructure replacement. Reliability improvements are only a secondary consideration. Liberty concludes that this switch replacement program contributes to employee safety by removing highly dangerous equipment. These switches comprise an antiquated type of underground oil switch and have a comparatively high failure rate. The switch vendor has issued several "Remove from Service" safety notices regarding them. PG&E claims that estimating benefits would have been difficult given the unpredictability of outages and acknowledges that the switches do not prevent outages, but only reduce their duration.

We disagree with DRA in its claim that if the switches needed to be replaced on PG&E's proposed accelerated timeline, PG&E could have previously accelerated their removal. PG&E's lack of action to accelerate the rate of removal in prior years does not justify continuing to delay the removal of these switches going forward.

4.16.3. Tie Cable and COE Cable Replacement

PG&E forecasts $7.4 million in MWC 56 capital expenditures in 2014 for Tie-Cable Replacements (i.e., ties connecting substations, not serving customers) with a three-year expenditure of $21.2 million. Tie-cables are 12-kV express circuits that transmit bulk power from one substation to another. The cables targeted for replacement were originally installed between 1935 and 1948, and have an increasing likelihood of failure. If multiple cables were to fail at the same time, substation outages would result, causing a large number of customers to experience long duration outages. PG&E's 2014 forecast for MWC 56 also includes COE Cable Replacement of $43.3 million. Through the COE Cable

Replacement Program, failed underground cable is replaced on a scheduled, prioritized basis, as opposed to an immediate, emergency basis.

DRA recommends that PG&E's 2014 combined forecast for Tie-Cable Replacement, COE Cable Replacement and Reliability-Related Replacement be set at the same level as PG&E's combined 2013 forecast, with the reductions in Tie-Cable Replacement and COE Cable Replacement. This translates to 2014 combined funding for Tie- Cable Replacement and COE Cable Replacement of $12.9 million. DRA objects to PG&E's forecast because spending in these three areas historically has been significantly below authorized amounts. PG&E's forecast increases in 2014 for Tie-Cable Replacement and COE Cable Replacement address backlogs caused by deferred maintenance.

PG&E acknowledges that there were several years where it spent less than the GRC authorized amount on "traditional" cable replacement. PG&E used the funding for cable replacement to pay for what it deemed to be higher priority work. PG&E does not dispute that its forecast increases in 2014 for Tie-Cable Replacement and COE Cable Replacement are intended to address backlogs. PG&E argues, however, that it should not be denied funding to address its cable replacement backlog.

If expenditures on TGRAM/TGRAL Replacement and Network Cable Replacement are taken into consideration, however, PG&E's 2010 spending on cable replacement was $27.0 million less than the authorized amount, not $32.6 million as claimed by DRA, and 2011 spending on cable replacement was approximately $5 million more than authorized, not $17.2 million less as claimed by DRA. Overall, PG&E's combined total recorded and forecast spending on MWC 56 for the years 2009 to 2013 is almost $60 million more than what PG&E forecast for the 2009-2013 period in the 2011 GRC.

DRA has not questioned the reasonableness or priority of PG&E's replacement projects, or any of the cost assumptions used in PG&E's forecast.

Given PG&E's history of forecasted and recorded expenditures for this activity since 2005, it is not clear whether PG&E needs to spend the requested amount or even will spend that amount if its forecast is approved.

TURN recommends a test year 2014 capital forecast of only $1.856 million, which is the average recorded spending from 2009-2011 and forecasted 2012-2013 spending. If PG&E ultimately implements a program that is more ambitious than one made possible by $1.856 million, TURN suggests that the higher spending can be trued-up in PG&E's 2017 GRC.

Discussion

We adopt DRA's proposed reduction to PG&E's forecast for Tie-Cable Replacement, COE Cable Replacement and Reliability-Related Replacement. We agree with DRA that ratepayers should not be responsible for paying for deferred maintenance on Tie-Cable and COE Cable Replacements. We thus adopt a 2014 forecast equal to PG&E's 2013 forecast. This adjustment reduces PG&E's forecast for 2014 by $37.8 million. Our rationale for adopting this treatment is similar to that for deferred maintenance on pole replacements, as discussed at Section 4.7. We refer to that discussion as rationale for our adopted forecast here. We also agree with DRA that adopting this lower level of funding for revenue requirement purposes does not mean that the backlog of traditional MWC 56 capital expenditures should be ignored, or delayed to a future GRC. Our adoption of DRA's recommendation merely means that ratepayers will not fund new increases for deferred maintenance for these programs that were funded in prior GRCs.

DRA notes PG&E has a pattern of either underspending or over forecasting. Although PG&E forecasted $25.7 million for Tie-Cable Replacements over 2009-2013 in the 2011 GRC, PG&E now only expects to spend $9.3 million during the 2009-2013 timeframe. PG&E forecasted $85.8 million over 2005-2009 in the 2007 GRC, but only spent $59.5 million during that timeframe, a $26.3 million difference.

4.17. Distribution Automation and System Protection

PG&E's capital forecast for Distribution Automation and System Protection in MWC 09 is $73.421 million in 2014 and $47.240 million in 2013, including escalation. The work covers the installation, upgrade, and replacement of remotely controlled automation and protection equipment, also known as SCADA, as distributed among: (1) Emergency Equipment Replacement; (2) Installation of Substation SCADA; (3) Replacement of Substation SCADA; (4) Replacement of Substation Protective Relays; (5) Installation of Feeder SCADA; (6) Replacement of Feeder SCADA; and (7) Fire Risk Management. PG&E's 2014 forecast for MWC 09 is approximately $51 million more than 2011 recorded costs due to increased installation of substation and feeder SCADA.

With SCADA, PG&E can remotely monitor system conditions and switch and/or de-energize equipment, which protects PG&E customers and employees from hazardous conditions and reduces the duration of outages. Additional SCADA capability will improve public and system safety and employee safety, improve distribution system reliability, increase operational flexibility, and provide a foundation for Smart Grid technologies, including FLISR deployment.

DRA recommends reductions of $10.025 million for 2014 and $9.024 million for 2013, covering all MWC 09 subprograms except Replacement of

Substation SCADA, which no party disputes. DRA supports adoption of PG&E's 2012 recorded costs of $37.518 million. PG&E agrees. PG&E also agrees with DRA's recommended reduction to the Emergency Equipment Replacement subprogram.

PG&E's forecast for Installation of Substation SCADA is $34.7 million for 2013 and $58.3 million for 2014. DRA recommends reducing PG&E's 2013 and 2014 forecasts for Installation of Substation SCADA by the amount that 2012 recorded costs exceeded the 2012 forecast. This results in a $1.5 million reduction for both 2013 and 2014. PG&E claims it did not shift work forecast for 2013 or 2014 into 2012. A significant contributor to PG&E's higher-than-forecast 2012 spending in this area was an unanticipated increase in unit costs. PG&E still anticipates spending at the level of its 2013 and 2014 forecasts, and completing the number of Substation SCADA installations set forth in those forecasts.

PG&E's forecast for Installation of Feeder SCADA is $3.0 million for 2013 and $5.0 million for 2014, excluding escalation. DRA recommends funding in 2013 and 2014 of only $1.161 million per year, the average of PG&E's recorded costs from 2009-2011.

TURN recommends reductions to Installation of Substation and Feeder SCADA totaling $46.027 million for 2014 and $20.378 million for 2013. ESC, however, argues that PG&E's forecast for Replacement of Protective Relays should be expanded. Liberty states that PG&E's distribution automation and system protection forecast work contributes to mitigation of important safety risks.

TURN recommends funding of $15.699 million per year for 2013 and 2014 for Installation of Substation SCADA, based on 2011 recorded costs. TURN claims that PG&E's forecast for Installation of Substation SCADA is much higher

than historical spending, and questions PG&E's claims about the safety, reliability, operational, and Smart Grid benefits of SCADA. TURN recommends 2013 and 2014 funding of $1.573 million for Installation of Feeder SCADA, based on average historical cost from 2007-2012. TURN's criticisms of Installation of Feeder SCADA are the same as for Installation of Substation SCADA.

PG&E claims that historical costs are not an appropriate measure of its planned future spending for feeder SCADA installations. PG&E has deployed substation SCADA for many years, but still has relatively low levels of SCADA penetration relative to its peers (59% penetration). PG&E's forecast will allow installing of SCADA at most substations by the end of 2017. Liberty states that "the substation and feeder SCADA programs contribute to system safety by providing remote device monitoring and operational capability. They are an important safety tool, providing remote monitoring and control capability."

PG&E provided a list of specific feeder SCADA sites it proposes to replace, consisting of the oldest vintage units on PG&E's system, further prioritized based on criticality of the circuit. From 2014 through 2016, PG&E plans to deploy an average of 50 new SCADA operable line switches per year at key locations on the distribution system to isolate portions of the system experiencing higher than average incidents of wires down. This equipment will allow distribution operators to de-energize electrical lines more quickly (and in some cases, automatically). In addition, PG&E plans to upgrade 170 existing line recloser controls annually to SCADA operability, and install cyber secure radio communication on about 20 existing SCADA ready devices.

PG&E claims that the forecasted increased substation SCADA installation work provides many benefits, but did not quantify those benefits. PG&E claims these remote monitoring and control capabilities will help prevent dangerous

conditions from occurring or resolve them more quickly. PG&E has not evaluated how many incidents the new SCADA installations will prevent, however, or their severity. SCADA controls on substation and line equipment will allow operators to access system conditions and remotely de-energize equipment. When a feeder SCADA switch fails, it jeopardizes PG&E's ability to monitor and/or operate that switch remotely, impacting PG&E's ability to quickly de-energize lines and increasing outage duration.

Liberty noted that it is often difficult to quantify safety benefits. PG&E also notes that increased safety is just one of several benefits of SCADA installations.

With regard to reliability benefits, PG&E participated in a benchmarking study led by Polaris Consulting that collected data from various North American electric utilities. This study showed that utilities with high percentages of substation SCADA penetration have lower Customer Average Interruption Duration Index (CAIDI) than PG&E.

TURN claims the benchmarking study does not clearly indicate how representative the utility survey participants were selected, and that PG&E made no effort to show a direct correlation between SCADA penetration and better reliability performance, or to quantify the benefit.

PG&E responds that although the survey participants' names were confidential, the study was led by a well-known consulting firm with no evidence the sample was not representative. PG&E claims similar benchmarking studies are routinely used in ratemaking proceedings. Although PG&E did not conduct a formal analysis to determine if factors other than SCADA supervision contributed to benchmark participants' lower CAIDI results, PG&E relies on its own experience to assert that substation SCADA installations contribute to lower

CAIDI by automating and accelerating the notification, restoration switching, and response processes during emergencies.

PG&E has not specifically quantified the reliability benefits of SCADA installation work, but claims that its own experience and engineering judgment support the premise that increased SCADA capability will reduce customer interruptions and outages.

PG&E has not quantified labor savings, or other potential savings, related to remote operation, to justify SCADA installation costs. Most of the operational benefits are nonfinancial, and not conducive to quantification.

PG&E claims that one of the benefits of substation SCADA is to help implement Smart Grid technology by supporting the deployment of distribution FLISR systems, which allow circuits to "self heal." TURN claims that if SCADA is needed to support FLISR, its costs should have been incorporated into the cost-benefit review of the FLISR program. PG&E did not incorporate the cost of SCADA into its cost-benefit review for FLISR installations because more than half of the urban and suburban substations where PG&E is likely to install FLISR already have SCADA capability. Also, supporting FLISR is only one of the reasons that PG&E forecasts installing and/or upgrading substation SCADA. As a result, PG&E claims it would not be appropriate to allocate the whole cost to the FLISR program. Nonetheless, even if the full cost of the additional substation SCADA needed to support FLISR installations is included in the cost of those installations, the VOS benefit-to-cost ratio for FLISR is still in excess of 20.

Discussion

We conclude that PG&E has justified an increased rate of substation and feeder SCADA installations, but we decline to approve the full funding request, as detailed below. We approve $43.7 million for 2014 Installation of Substation

SCADA capital costs, as well as $2.25 million and $3.75 million for Installation of Feeder SCADA in 2013 and 2014, respectively, which is approximately a 25% reduction from PG&E's forecasted costs. Given the other large funding increases at issue in this GRC, we conclude that burdening ratepayers with full funding of these projects has not been sufficiently justified. We believe our reduction is justified by some of the concerns raised by TURN in that PG&E has not done an integrated distribution substation SCADA/Feeder SCADA automation and other possible distribution control, protection and monitoring systems. However, given its proximity to 2012 recorded costs, we adopt PG&E's 2013 proposal of $34.65 million for Installation of Substation SCADA.

We also find it reasonable to adopt $2.0 million for 2013 and 2014 Replacement of Feeder SCADA, Fire Risk Management, and Replacement of Substation Protective Relays. These subprograms merit funding based on the criticality of such work to address the risk of safety or reliability issues that can arise from damaged or unreliable Feeder SCADA switches and reclosers, wildfires, and substation transformer equipment damage. We reject DRA's proposed reductions to PG&E's forecasts, which are largely based on PG&E's recorded historical spending for these programs, and instead adopt PG&E's proposals, with the exception of 2013 Replacement of Feeder SCADA, which we reduce by $1.0 million to bring into line with the approval of preventative maintenance spending amounts for Fire Risk Management and Replacement of Substation Protective Relays.

Operational benefits of substation SCADA include: the ability to remotely switch substation equipment; the ability to obtain real time information about the condition of the system, which allows operators to proactively take actions to avoid equipment overloads and failures; and the ability to use historical data

from the SCADA to examine line loading trends, forecast future loading, and perform outage investigations.

PG&E seeks to justify SCADA installation on the basis of not just operational benefits alone, but on a combination of safety, reliability, operational and Smart Grid benefits. PG&E argues that all of these benefits together justify its proposed increased spending on SCADA, not any one of the benefits alone. We concur with PG&E that all of these benefits support an increase in spending on SCADA and we believe that the funding approvals contained herein will be sufficient to allow PG&E to move forward with their program.

4.18. Rule 20A Conversions of Overhead Lines

Rule 20A allows a city or county to convert existing overhead lines to underground at PG&E's expense. Cities and counties are allocated a certain number of "work credits" per year. When they have accumulated sufficient credits to fund a project, the project goes into PG&E's work queue for completion. For many years, the amount of work credits allocated was higher than the amount of Rule 20A work performed. As a result, PG&E has a substantial accumulation of unfunded projects to be completed. For this GRC, PG&E anticipates eliminating the accumulation of unfunded projects by the end of 2017, while maintaining the current average project duration of seven years.

PG&E's 2014 capital forecast for Rule 20A in MWC 30 is $88.222 million, including escalation. PG&E's 2013 forecast is $88.451 million, including escalation. PG&E's forecast is about $54.594 million higher than 2011 recorded costs, to address a backlog of work. PG&E also requests that the Commission extend through 2016 the annual work credit allocation amount of $41.3 million adopted in the 2011 GRC decision, which will allow PG&E to reduce the

accumulation of approved Rule 20A work accrued under the previous work credit allocation method.

DRA recommends adoption of PG&E's 2012 recorded costs in place of PG&E's 2012 forecast costs. PG&E agrees. DRA, however, recommends a forecast reduction of $34.466 million for 2014 and $34.555 million for 2013, claiming that PG&E failed to justify its 2013 and 2014 forecasts, which exceed historical amounts. DRA claims that 2014 funding should be based on 2012 recorded costs because: (1) PG&E's 2011 and 2012 reports to the Commission regarding Rule 20A work show that PG&E does not need additional funds; (2) PG&E spent much less than the Commission authorized for Rule 20A work between 2007 and 2012; and (3) recorded spending for 2012 was lower than forecast. DRA also claims that if PG&E is funded at its forecast, there is no certainty it will perform the work.

PG&E claims that historical spending is not a reasonable basis for a forecast, and that it is planning to perform more Rule 20A work than in the past in order to complete projects already underway and to address customer demand for undergrounding of overhead electric distribution facilities in a more timely fashion. There are $274.1 million worth of unfunded customer Rule 20A projects - a combination of partially completed projects and planned work that has not been started - in PG&E's project queue.

PG&E identified and described in its workpapers the specific projects used to calculate its forecast. PG&E claims it needs the full amount forecast to satisfy ongoing customer project demands and complete accumulated undergrounding requests initiated in prior years. The variance between 2012 forecast and recorded Rule 20A spending was due to crews being diverted for Hurricane Sandy support, December storm activity, and reductions to fund higher priority

work within Electric Operations. PG&E asserts that it has the resources and capabilities to meet the elevated number of forecast projects over the 2014-2016 GRC cycle and has adjusted its work procedures to complete projects more quickly.

Discussion

We adopt DRA's proposal to adjust PG&E's 2013 and 2014 forecast to reflect 2012 spending levels. While we recognize that in many instances, PG&E's past expenditure levels may not indicate what future spending levels will be, we disagree that PG&E's forecast of increased levels of Rule 20A project activity have been shown to be reliable in this instance. As noted by DRA, 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. We are not persuaded that PG&E's forecasts for Rule 20A project activity is reliable in this instance.

4.19. Streetlight Program

PG&E's 2014 forecast for light-emitting diode (LED) Streetlight Replacement in MWC 2A is $18.6 million. This is a new program so there were no 2011 recorded costs. PG&E's LED Streetlight Program involves replacement of PG&E-owned High Pressure Sodium Vapor (HPSV) streetlights with "liquid-emitting diode" streetlights. LED streetlights are more energy efficient and longer lasting than HPSV streetlights. Due to the energy savings associated with LED streetlights, which offset the facility cost of LED replacement, PG&E claims the replacement ultimately will be cost-free to customers. According to PG&E, replacing conventional streetlights with LEDs will improve safety and increase energy efficiency, reliability and customer satisfaction. With a few exceptions, PG&E's forecast is for the replacement of all PG&E owned

non-decorative streetlights by the end of 2016, and assumes total participation from PG&E's customers.

DRA and TURN recommend implementing streetlight replacement over 24 years, rather than the three years forecast by PG&E, resulting in 2014 funding of $2.468 million, a $16.132 million reduction from PG&E's forecast.

CAL-SLA advocates the widespread implementation of LED technology. CAL-SLA also recommends that PG&E's proposal include decorative street lights, and that CAL-SLA's proposed cost of "$6.08 million for HPSV street light burnouts and unit cost of $308" be adopted. CAL-SLA further recommends that "LED program annual revenue requirement should reflect the Commission approved HPSV burnout unit cost."

CCSF made no financial recommendation for the LED Streetlight Program, but requested that streetlights in CCSF's jurisdiction be included in the program. CCSF also recommends that the Commission should extend the capital cost recovery period over a period of time that better matches the expected lifetime of the LED lights

PG&E argues that extending the program beyond three years would needlessly defer participating customers' energy savings. The program has the potential to reduce streetlight energy consumption by 52.8 million kilowatt-hours (kWh) annually at program completion, which will result in lower costs to customers. DRA and TURN's recommendation would defer more than 86% of light replacements beyond 2017. The energy savings described above will also provide significant environmental benefits. Using Environmental Protection Agency equivalencies for greenhouse gas (GHG) reductions, 52.8 million kWh annually is comparable to the carbon dioxide emissions from more than 86,000 barrels of oil consumed. DRA and TURN's recommendation

results in deferring nearly the entire environmental benefit of this program beyond the 2014 GRC cycle.

PG&E's proposed three-year program also takes advantage of pricing discounts associated with bulk purchases of materials and program efficiencies gained through application of dedicated resources for construction and program oversight. PG&E estimates that the approach proposed by DRA and TURN would result in increased per unit construction labor and material costs.

CCSF requests that CCSF streetlight classes should be included in PG&E's proposed LED Streetlight Program. PG&E indicates that if its proposed LED Streetlight Program is approved for other LS-1 customers, PG&E is willing to apply similar options to PG&E-owned lights serving CCSF, but CCSF must determine if the program offers sufficient benefits to make it worth pursuing replacements.

CCSF shares the view expressed by other parties that PG&E's schedule and anticipated participation level for LED conversions may be overly ambitious. TURN and DRA recommend that PG&E extend the program over a longer period given PG&E past requests for LED Streetlight funding. As TURN notes "the Commission approved a 2011 capital spending forecast of $18.5 million, yet PG&E spent nothing on the program in 2011 through 2013." Rather than lengthening the schedule for the program, CCSF recommends that approval of PG&E's LED Streetlight Program be tied to measures ensuring that the revenue approved for the LED conversion work is actually used for implementing the program. CCSF also agrees with CAL-SLA that PG&E must provide assurances that LED conversions can occur quickly following customer requests.

PG&E argues that it is not necessary to develop specific reliability and performance commitments because it has "already set performance goals for

streetlight maintenance – to repair 90% of streetlight burnouts within five days, and complete 75% of underground and/or cable repairs related to streetlights within 30 days." However, PG&E fails to inform the Commission that these standards are unwritten (allegedly developed in 2012). CAL-SLA recommends that PG&E include decorative streetlights in the LED Replacement program. However, the high cost of replacing decorative streetlight fixtures with LEDs makes it impossible for PG&E to include them in its LED Streetlight Program as currently constituted. The LED Streetlight Program as proposed is effectively "self-funding," *i.e.*, customers' estimated energy cost savings will more than offset the estimated increase in revenue requirement to support the program. PG&E's ability to offset the increased revenue requirement is based on estimated replacement fixture capital unit costs ranging from $150 to $543, with most replacements being near the lower end of this range.

PG&E's calculates that including the higher priced replacements for the approximately 25,000 PG&E-owned decorative streetlights in this program would result in an annual revenue requirement to fund the replacements that would exceed the projected annual energy savings from the program. Thus, including decorative fixtures would make the program no longer capable of "self-funding" and would result in cost shifting to non-participating customers.

Discussion

We approve PG&E's 2014 forecast of $18.6 million for LED Streetlight Replacement in MWC 2A. We decline to reduce funding for the LED Streetlighting replacement program as proposed by DRA and TURN. Such reduced funding would significantly delay program implementation and preclude customers from realizing most of the program's cost savings until after 2017. PG&E's funding forecast is responsive to customer requests for assistance

in reducing energy costs by addressing streetlight replacements promptly. PG&E's LED Street lighting program is effectively self-funding, where customers' energy cost savings will more than offset revenue requirement increases to support the program.[45]

Although PG&E did not previously implement spending for this program in the 2011 GRC cycle, as PG&E explains, the 2011 GRC settlement specifically removed funding to cover LED streetlight replacements. Since we are expressly adopting funding for the program in this GRC, however, we expect PG&E to move forward with prompt implementation of the LED streetlight replacements.

We decline to adopt the CAL-SLA proposal that PG&E include decorative streetlights in the LED Replacement program. As PG&E notes, the cost of decorative LED fixtures, ranging from $724 to $1,223 per unit, would eliminate the cost-effectiveness of the program, and result in cost shifting to non-participating customers.

We recognize that all local jurisdictions, including CCSF, should have the opportunity to participate in the LED Streetlight Program. CCSF is not yet included in the program because CCSF is not a LS-1 customer. CCSF will need to negotiate a different payment mechanism from the one designed for other customers. If the LED Streetlight Program is approved for other LS-1 customers, however, PG&E agrees to apply similar options to PG&E-owned lights serving CCSF. Accordingly, we direct PG&E to promptly enter into negotiations with

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[45] The cost offset for the program is based on replacement fixture capital costs ranging from $150 to $450 per unit, with most replacements being at the lower end of the range. (*See* Exh. 308 (PG&E Cross Exhibit). PG&E's breakeven analysis for the program is shown at PG&E-4, WP 19-12, line 32.

CCSF to develop an appropriate payment mechanism so that CCSF may participate in the benefits of LED Streetlight replacements.

4.19.1. Rate Design

PG&E's forecast includes cost recovery based on the expected life of the assets. Newly installed PG&E-owned LED streetlights will be added to Asset Class EDP37303 – Federal Energy Regulatory Commission (FERC) Account 373, which has a proposed ASL of 25 years. This reflects a proposed increase in service life in this asset class over what is currently in place. For newly installed LED streetlights, PG&E will recover capital costs over the proposed service life for the asset class - in this case 25 years.

CCSF criticizes PG&E's showing on the grounds that PG&E has proposed recovery of LED capital costs within three years. CAL-SLA recommends that PG&E's revenue requirement for LED Streetlight Replacement should be modified to reflect CAL-SLA's proposed adjustment to unit costs for PG&E's Streetlight Burnout program in MWC K.

Discussion

We conclude PG&E's proposed cost recovery for the LED Streetlighting Replacement Program is reasonable and hereby adopt it.

PG&E is proposed that the capital cost recovery period associated with the LED Streetlight Program is based on the projected life of the assets to be installed, and is not limited to three years.

PG&E forecasts charging customers who participate in the LED Streetlight Replacement program an incremental facilities charge during this three-year GRC period to ensure that the cost of LED streetlight replacement is not borne by non-participating customers (i.e., customers who buy electricity from PG&E, but own their own streetlights). PG&E estimates that, after this initial period when

RRQ requirements will be higher due to start-up costs and the need to recover the remaining plant value of HPSV streetlights retired in the course of program work, the base facilities charge will be sufficient to permit PG&E to recover the remaining costs related to the LED Streetlight Replacement program. Therefore, PG&E expects to discontinue incremental facility charges after the completion of the three-year implementation plan, which corresponds to a single rate case cycle. However, any final determination in that regard will need to be addressed in the 2017 GRC proceeding.

4.20. Electric Distribution Support Activities

Electric Distribution Support Activities include: (1) Distribution Support expenses (MWC AB); (2) training curriculum creation and revision expenses (MWC DN); (3) tools and material overdraw (MWC 05); and (4) real estate projects with an Electric Distribution operations focus (MWC 78). PG&E also includes in MWC AB and MWC 05 proposed productivity offsets to escalation of its expense and capital forecasts for all of its Electric Operation programs.

4.20.1. Technical Training Curriculum (MWC DN)

PG&E forecasts $684,000 for MWC DN for technical training curriculum to revise existing and create new training material and course curricula. PG&E argues that the skills and experience of its workforce are integral to providing safe and reliable service. PG&E revises existing and creates new training materials and course curriculums.

DRA recommends no funding because there are no recorded expenses for MWC DN. DRA claims there is no reliable historical data to evaluate and no way to ensure that PG&E is not requesting additional funding for a routine ongoing expense.

PG&E explained in a data request response that there are no recorded historical costs for curriculum development in MWC DN because those costs were recorded outside MWC DN in Provider Cost Centers and order numbers in the Electric Operations and/or Human Resources (HR) organization. PG&E did provide a list of courses and the estimated amount spent on curriculum development from 2007-2012

PG&E's original 2014 forecast for MWC DN was $4.135 million, or $684,000 more than the two-year average of PG&E's recent historical spending on curriculum development. PG&E proposes that instead of adopting $0 for curriculum development, that the Commission adopt a forecast of $684,000.

PG&E's revised forecast of $684,000 reflects the difference between the two-year average of estimated costs in 2011 and 2012 for technical curriculum development recorded outside of MWC DN ($3.451 million) and PG&E's original forecast for MWC DN ($4.135million).

Discussion

We conclude that PG&E's forecast of $684,000 for MWC DN is reasonable and adopt it. PG&E originally forecast $4.1 million, including escalation, in 2014 to address the curriculum requirements for new courses. By limiting the forecast only to the increment of $684,000 above recorded costs, we conclude that PG&E addresses DRA's concern about double counting of costs. Approval of this funding will help ensure that the training curriculum is updated to reflect new training needs so that employees have the updated skills and qualifications needed to do their jobs reliably and safely.

4.20.2. Electric Distribution Productivity Offset (MWC AB and MWC 05)

PG&E commits to offset forecasted escalation for 2012-2015 with productivity savings from its Electric Operations Improvement Plan. PG&E includes offsetting expense reductions in MWC AB of -$10.7 million covering all Electric Operations line of business, with corresponding reductions of -$43.7 million for capital in MWC 05. For expense, the offsetting reductions apply to 2013 and 2014. For capital, the offsetting reductions apply to 2013 to 2015. PG&E's 2012 forecast did not include escalation, so PG&E makes no offset for 2012.[46]

To estimate the offsetting escalation amounts, PG&E split its forecasts for Electric Operations into labor and non-labor costs using historical values and applied standard escalation rates.[47] DRA calculates escalation differently, but accepts PG&E's expense and capital escalation offsets.[48] PG&E explains that if DRA's or other parties' recommendations for lower forecasts are adopted, then an adjustment to the offset will be necessary. PG&E argues that a lower forecast implies that a lower amount of work will be performed, with a corresponding decrease to the level of savings associated with efficiencies.

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[46] Exh 374, Joint Comparison Exhibit at 2-163.

[47] Exh. 17 (PG&E-4) at 20-6, lines 24-29. PG&E's overall forecast was slightly revised for errata and concessions. PG&E did not update the escalation values, however, because (a) the change to the forecast is small and (b) escalation has no net effect on PG&E's forecast. Exh. 49 (PG&E-15) at 14-347, fn. 5.

[48] DRA cites an incorrect value for PG&E's capital offset of -$46.6 million. The correct value for the capital escalation offset for 2014 is -$43.656 million.

TURN argues that PG&E's claim that the cost escalation amount is representative of productivity savings is an unsupported assumption. TURN argues that Electric Distribution expenditures for IT are vastly greater than PG&E's claimed benefits, and that PG&E needs to achieve greater benefits or lower costs. TURN also recommends a further reduction of $3.57 million in MWC AB to capture a portion of PG&E's 2015 expense escalation offset in the TY2014 forecast.

Discussion

For purposes of test year expenses and capital for Electric Distribution, we apply an offset to recognize efficiencies in cost control. Based on the approach proposed by PG&E, as explained above, we apply the expense offsets to MWC AB and the capital offsets to MWC 05. The offsets calculated by PG&E are based upon its PG&E's forecasts of expenses and capital for Electric Distribution. To the extent that Commission-adopted expense and capital forecasts differ from PG&E forecasts for Electric Distribution, we recognize that the offset amount calculated by PG&E needs to be adjusted proportionately. To make the adjustment in the offset, we multiply PG&E's offset amounts by the percentage difference between our adopted forecast versus PG&E's forecast for Electric Distribution expenses and capital amounts.

TURN argues that PG&E's forecast 2014 expense escalation offset should be increased by the amount of savings expected in 2015, normalized over the two attrition years of the GRC cycle (2015 and 2016). TURN calculates this amount as an additional $3.57 million. TURN thus proposes that the 2014 forecast be reduced by productivity savings in the amount of $14.27 million, (instead of the $10.7 million forecast by PG&E).

PG&E claims its attrition proposal already takes productivity savings into consideration, and that further test year adjustments for the $3.57 million proposed by TURN would double count the savings. We conclude that since the $3.57 million offset calculated by TURN relates to efficiencies during the attrition year of 2015, there is no valid basis to apply those additional efficiencies to the 2014 test year. We separately address the appropriate post-test year ratemaking treatment later in this decision.

4.20.3. Edison Electric Institute Dues (MWC AB)

PG&E includes in its MWC AB forecast a portion of its membership dues paid to Edison Electric Institute (EEI). The EEI is an association of U.S. shareholder-owned electric companies that provides industry data, strategic business intelligence, conferences and forums, and other products and services. PG&E forecasts $450,000, excluding escalation, for EEI dues related to Electric Distribution in 2014. PG&E's forecast is based on allocating 25% of the $1,610,719 dues paid to EEI in 2011 below the line. PG&E's argues allocating 25% of its EEI dues below-the-line is reasonable. DRA recommends that customers should fund no more than 81% of PG&E's 2014 forecast for utility fees and membership dues.

TURN proposes that 43.3% of EEI dues be allocated below-the-line rather than allocating only 25% as PG&E does. TURN claims that the best available data indicates that 43.3% of EEI dues pertain to lobbying, legislative policy research and advocacy, regulatory advocacy, public relations, advertising, donations, and club dues. TURN examined the last available data audited by the National Association of Regulatory Utility Commissioners, EEI's 2005 Spending Data, as well as more recent but limited (and unaudited) data on EEI's schedule

of expenses for core dues activities from 2005-2009 provided to the Arkansas Public Service Commission.[49] Based on analysis of this data, as well as information on PG&E's invoice from EEI, TURN developed a method for estimating the percentage of EEI's activities to be allocated below-the-line based on spending categories previously disallowed by the Commission.

Discussion

We adopt TURN's recommendation to allocate 43.3% of EEI dues below the line. We thus exclude $701,768 of EEI dues paid by PG&E in 2011, as opposed to the $405,180 that PG&E assigned below the line. We conclude that TURN's analysis and proposed allocation reasonably reflects the categories of disallowable EEI dues that offer no ratepayer benefits. We find no evidence offered by PG&E to rebut TURN's analysis, nor the reasonableness of TURN's ratemaking recommendation for EEI dues.

Consistent with both PG&E and TURN proposals, we allocate above-the-line EEI dues in equal parts to generation, distribution, and transmission. TURN does not agree, however, with PG&E's approach to escalating the 2011 costs. PG&E uses the administrative escalation factor for MWC AB in generation but a higher escalation factor (11.1%) for MWC AB in distribution. TURN applies the same escalation factor to MWC AB, based on the administration escalation factor. We find no basis for applying PG&E's higher escalation factor, and find TURN's escalation approach more reasonable. Accordingly, we adopt TURN's EEI dues

[49] Ex. 116 (TURN, Marcus Testimony) at 69-70.

forecast for MWC AB which is $224,000 less than PG&E's consisting of $117,000 for distribution and $107,000 for generation.[50]

For MWC 05, no party disputes PG&E's 2014 forecast for Tools and Equipment and Escalation, and DRA recommends that PG&E be funded for 2012 at the level of its recorded costs, rather than its 2012 forecasts. PG&E agrees with this recommendation. PG&E notes, however, that while DRA accepts PG&E's escalation offset value, an adjustment is necessary to the extent that the Commission adopts an expense estimate lower than PG&E's proposal.

4.20.4. Electric Operations Focused on Real Estate Projects (MWC 78)

PG&E forecasts capital expenditures (excluding escalation) of $870,000 for 2012, $6.286 million for 2013, and $1.639 million for 2014 for MWC 78 for Electric Operations building facility management. The forecast is for work at five locations at a cost of $205,000 per site. PG&E plans to increase the number of sites to 10 for 2015 and 2016. Of PG&E's total funding for 2014, $614,000 is for continued normal operation of facilities associated with Electric Distribution, based on 2011 costs. The remaining $1.025 million is for increased building security for installation or modification of fencing and for card readers and security cameras.

For MWC 78, DRA recommends $2.77 million for 2012, which equals PG&E's recorded costs. PG&E agrees with DRA's recommendation for 2012. DRA objects to funding increasing building security in 2013 and 2014, and

[50] Ex. 116 (TURN, Marcus Testimony) Table 33 at 71.

recommends funding of $640,500 for 2013 and $635,100 for 2014, a reduction to PG&E's MWC 78 forecast of $5.67 million for 2013 and $1.02 million for 2014.

DRA claims that security costs are already built into PG&E's base costs. PG&E agrees that portions of historical expenditures, which were $614,000 in 2011 (and averaged less than $400,000 per year for 2007 through 2011), may have been used for security measures. However, portions of these expenditures were also used for purposes besides security. None of the $614,000 spent in 2011 was related to security.

PG&E's real estate forecasts for Shared Services (Exhibit 30 (PG&E-7)), do not include funds for increasing security at Electric Operations facilities.

PG&E denies DRA's claim that for every project in PG&E's 2013 forecast, as a result of PG&E's DCC consolidation project, space will be freed in existing distribution control centers sufficient to address Electric Operations' proposed facilities' needs.

Discussion

We adopt 2012 recorded expenditures of $1.524 million for MWC 78. We adopt PG&E's capital forecasts for MWC 78 in the amounts, $6.286 million for 2013, and $1.639 million for 2014. The approved funding recognizes the need for increased security measures above amounts built into embedded costs. We recognize that PG&E has been experiencing security related issues at various facilities. To address these concerns, PG&E's forecasts expenditures provide appropriate measures for improved security. Authorizing the requested funding for MWC 78 will enable PG&E to provide adequate security at its buildings to reduce the risk of property theft and unauthorized access.

5. Customer Care

5.1. Introduction

PG&E's forecasts Customer Care expenses for 2014 of $454.6 million, which is $71.0 million, or 15.6% greater, than recorded expenditures for these activities in 2011. Customer Care covers a range of services and programs to meet retail customers' needs, including responding to customer inquiries and preparing customer bills, notices, and payment processing. PG&E also seeks funding to raise customer service expectation standards. PG&E also proposes the transitioning of recorded meter reading balancing account costs to the GRC. Forecast costs are offset by avoided cost savings, including $28 million in SmartMeter™ benefits.

PG&E's request to adjust customer fees for reconnections and insufficient funds is unopposed. We adopt that unopposed request.

5.2. Customer Inquiry Assistance (MWC DK)

For 2014, PG&E forecasts $119.09 million in 2014 incremental expenses in MWC DK for Customer Inquiry Assistance.[51] Increases over 2011 levels are largely due to: (1) Contact Center costs to improve customer satisfaction levels ($5.9 million); (2) cost escalation ($8.7 million); (3) more customer service representatives (CSRs) to offset increasing call handling complexity ($11.2 million); (4) Customer Advocacy, training and supervision costs ($5.2 million); (5) Relocation costs associated with Contact Center expansion

[51] In Errata, PG&E revised its initial forecast of $124.9 million, removing Peak Day Pricing (PDP) and correcting Contact Center costs. In Rebuttal, PG&E revised its forecast to $119.1 million, withdrawing its PTR Program forecast ($4.6 million) and increasing self-service savings to $1.3 million.

($1.2 million); and (6) costs of the Peak Time Rebate (PTR) program ($4.6 million). The costs are partially offset by self-service option improvement savings, technology refresh savings, new-hire wage rate savings and reduced repeat calls (-$14.2 million).

DRA and TURN recommend a reduction to PG&E's forecast of $22.6 million and 8.9 million, respectively. The differences between PG&E, DRA, and TURN are itemized on the table below (Table 5-1 of PG&E's Brief).

5.2.1. Training for CSRs

PG&E forecasts $1.6 million above 2011 levels for increased training of CSRs. The increased funding would add two hours of training per month for each of its CSRs to address the added complexity and the increasing breadth of topics that CSRs must be equipped to address with customers.

DRA opposes any funding increase for additional CSR training, arguing that several potential CSR training improvements could be implemented by shifting existing procedures without new incremental funding. DRA refers to the Boston Consulting Group (BCG) report from 2010 which evaluated PG&E's customer contact center performance and identified different approaches to improve training without increasing overall funding levels. DRA claims that implementing the BCG recommendations would effectively offset the need for increased funding that PG&E requests for purposes of CSR training.

DRA suggests that PG&E could reduce training costs by shifting "front-loaded" initial training to ongoing training based on BCG's finding that PG&E's up-front training activities are more extensive than the other benchmarked companies. PG&E argues that the comparable benchmarks used by BCG for its initial training assessment did not include any regulated utilities. Given that PG&E CSRs operate within a complex regulatory environment, PG&E

argues that additional up-front training is necessary as compared to CSRs in unregulated industries.

TURN recommends a $0.1 million reduction to PG&E's forecast based on TURN's opposition to additional CSR staffing associated with ASA and CAT as discussed below. TURN's recommendation reflects a pro rata reduction to PG&E's forecast training costs based on less staff to train.

Discussion

We adopt PG&E's proposed increase in funding for CSR training, based on plans to add two hours of training per month for each CSR for 2014. PG&E's training forecast is based on 1,020 CSRs. Our adopted forecast is 2.8% lower to reflect the somewhat lower count of CSRs based on our adopted 2014 test year results. We subtract 29 from PG&E's count of 1,020 CSRs to arrive at a total of 991 CSRs.[52] We conclude that increased funding of two hours per month for each CSR training is appropriate in view of the added complexity of issues that CSRs must address. We are not persuaded by DRA's opposition to the funding proposal. Since PG&E is already making use of the training initiatives identified in the BCG Report, we find that use of these training initiatives does not offset the need for increased funding for training. We are not persuaded that PG&E's need for training funds can be reduced by shifting initial training to ongoing training. BCG found that PG&E's up-front training activities are more extensive than those of the other benchmarked companies. Comparable benchmarks used by BCG for its initial training assessment did not include regulated utilities.

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[52] The reduction of 29 CSRs is based on denial of (a) PG&E's request for 10 CSRs to reduce local office waiting lines and (b) 19 CSRs to expand the Customer Advisor Team.

Since PG&E CSRs operate within a complex regulatory environment, however, we conclude that the additional up-front training proposed by PG&E is reasonable as compared to CSRs in unregulated industries.

TURN does not oppose funding of two hours of training per month per CSR, but calculates a reduced forecast cost based on a lower CSR employee count and assuming TURN's recommendations for a lower CSR staffing. Our adopted forecast incorporates an allowance of two hours of training per month applied to the number of CSRs in our adopted forecast.

5.2.2. Improvement in Average Speed of Answer (ASA) Time

PG&E forecasts incremental funding of $5.9 million to hire 68 CSRs to improve the "Average Speed of Answer" (ASA), that is, the time customer waits to conduct a transaction by phone. Based on the BCG Report, PG&E's ASA performance is below the industry average. Customer surveys also indicate that wait times to conduct transactions by phone are too long. PG&E seeks to improve service, particularly for customers experiencing the longest wait times to speak to a CSR. PG&E's goal is to increase the ASA speed from 59 seconds (using 2011 data) to a first quartile performance ASA of 28 seconds for 2014 (i.e., a 31 second improvement).

DRA and TURN recommend no funding increase DRA notes that PG&E's performance level historically has been above the Commission's adopted telephone service level (TSL) standard requiring that PG&E answer 80% of customer calls within 20 seconds. DRA believes PG&E can continue to meet at least that standard with the completion of the Contact Center Refresh project. DRA argues that other tools can reduce customers' waiting time without hiring more CSRs. Specifically, DRA points to the implementation of the Contact

Center Refresh project and to the use of Virtual Hold Technology (VHT). By using VHT, a customer can significantly reduce the amount of time spent waiting on the phone line.

PG&E notes that the TSL standard only deals with calls answered by PG&E's automated system. The TSL metric does not measure the customer's waiting time to reach a live CSR. PG&E thus argues that its forecasted increases remain necessary to reduce the wait time for customers to speak to a live CSR. PG&E also notes that its ASA improvement target already include the savings from the Contact Center Refresh.

PG&E used a formula to translate the target ASA improvements into incremental CSRs hours required, and then generated the forecasted increase of 68 FTE. However, TURN claims that the number of CSRs has not historically been strongly correlated with ASA. On this basis, TURN questions the validity of PG&E's formula for deriving the number of incremental CSRs to reach PG&E's ASA target. TURN thus questions PG&E's premise that 68 CSRs equate to a 31 second reduction in CSR ASA.

PG&E claims, however, that TURN's correlation claims are based on incorrect data that reflect headcount rather than FTE hours of labor. TURN also erroneously included other employee categories in the CSR total. Based on these data errors, PG&E disputes TURN's claim that there is no strong historic correlation between ASA and CSRs.

In the alternative, TURN suggests limiting funding to PG&E's forecast of 2012 incremental expense over 2011 recorded of $556,000. Based on PG&E's per-employee labor cost for 2014, this equates to six additional FTEs.

Discussion

We adopt PG&E's forecast. We conclude that improvement in ASA performance is warranted in view of the BCG report findings that PG&E performance is below industry standards. The Commission-adopted TSL metric refers only to the weighted ASA for calls handled live and calls handled by PG&E's automated system. Even though PG&E currently satisfies the TSL metric, faster speed is still needed in answering calls handled live, consistent with the BCG Report findings. We accept PG&E's calculation that achieving first quartile results would require an increased ASA of 31 seconds. DRA erroneously inferred that PG&E's requested staffing increase would result in only a four-second improvement. DRA erred by comparing PG&E's 2011 blended ASA of 32 seconds to PG&E's 2014 target live ASA (28 seconds).

We also conclude that PG&E's forecasts for the volume of CSR-handled calls and ASA improvements already include the savings that will result from the Contact Center Refresh. PG&E also accepted DRA's higher forecast of Self-Service Option Improvement Savings based on an increased interactive voice response take rate enabled by the Contact Center Refresh project

TURN raises questions as to the degree to which the ASA is correlated with CSR resources. We cannot rely on TURN's analysis to refute claimed correlations over time between the required number of CSRs and the corresponding ASA. TURN erroneously used headcount data provided for another purpose (i.e., to illustrate its historic Contact Center Agent-to-Supervisor ratio) and imported the data into a different analysis comparing the number of CSR FTE employees to the corresponding ASA. In any event, even apart from TURN's analysis, we believe that a variety of factors that vary over time ultimately influence actual ASA results.

While the available data leaves questions as to the precise number of CSRs needed to achieve a first quartile ASA during 2014, we believe that on balance, PG&E offers the closest approximation of a reasonable staffing level. Accordingly, we adopt PG&E's forecast based on an increase of 68 CSRs.

5.2.3. Expansion of Customer Contact Centers

PG&E forecasts $15 million for 2014 capital costs and $1.2 million in incremental 2014 expenses to expand the Sacramento and Fresno Customer Contact Centers by 135 seats each in 2014 to accommodate increased customer service response and to offset attrition in the Stockton and San Jose Contact Centers. PG&E argues that expansion will (1) accommodate an increase of 200 net positions in 2014; (2) address safety concerns in the Stockton area; and (3) resolve parking limitations in the San Jose Contact center. DRA and TURN oppose PG&E's funding increase for expansion of its Contact Center facilities, arguing that PG&E lacks justification.

DRA believes expanding the number of workstation seats is unnecessary due to the current number of workstations already available, and the added capabilities from the Contact Center Refresh project. DRA argues that PG&E doesn't need a separate desk for every employee since CSRs with different work schedules can share desks. PG&E's planned call center staffing at peak time was 490 CSRs. Due to the current number of workstations available and the lack of quantified benefits from expansion of 270 CSR workstations, DRA recommends no capital funding increases.

TURN has recommended a total CSR headcount reduction of 88, including 68 CSRs to improve ASA, 19 CSRs for the Customer Advocacy Team (CAT), and one supervisor for CAT. TURN calculates that a proportional reduction in

PG&E's forecast of Contact Center corporate real estate 2014 costs would be $5.050 million in capital and $396,924. Assuming that TURN's staffing recommendations are adopted, the PG&E's Contact Center build out costs would be reduced by these amounts.

Discussion

We adopt PG&E's forecast, and conclude that the requested expansion is justified. As PG&E explains, contact center expansions in Sacramento and Fresno will accommodate new service levels and offset attrition in Stockton and San Jose. Broad-scale use of workstation sharing, as suggested by DRA, is feasible only where a Contact Center is open long enough to accommodate two full-time work shifts, or at least 17 hours per day. Neither the Sacramento nor Fresno Contact Center is open more than 14 hours per day, however, thus precluding full-time workers from sharing the same space. We conclude that the forecasted expansion will also address safety concerns in Stockton and parking limitations in the San Jose center. Consequently, the planned expansion is reasonable in view of the factors considered above.

5.2.4. CSR Supervision and Support

PG&E forecasts increased expense of $1.8 million for additional CSR supervision and support. PG&E claims that the additional supervisors are necessary to address BCG's industry benchmarking findings of gaps in PG&E's CSR soft skills such as customer service, problem solving, and communication style. PG&E forecasts Contact Center supervisor requirements assuming a ratio of 14.5 CSRs for every supervisor (at a cost of $109,861 per supervisor). PG&E thus seeks to hire 16 additional supervisors to compensate for increased CSR staffing levels, and to improve PG&E's agent-to supervisor ratio relative to first quartile industry standards.

DRA and TURN recommend respective reductions of $1.8 million and $0.7 million for incremental expenses associated with supervision and management of CSRs. DRA argues that PG&E apparently does not consider additional supervision a necessary component of safe and reliable service because PG&E did not increase supervisors in 2012 despite increased CSR staffing.

TURN does not oppose PG&E's target agent-to-supervisor ratio, but recommends reduction to PG&E's supervision forecast based on TURN's reduced staffing estimates for non-supervisor CSRs. Assuming a lower forecast of CSRs, TURN forecasts a lower number of Contact Center supervisors to maintain PG&E's 14.5:1 ratio. TURN's forecast of CSR staffing levels is 87 lower than PG&E's (combining 68 associated with ASA and 19 for CAT). TURN's assumed staffing level reduces PG&E's supervisor needs by 6 supervisors, with supervisor costs reduced by $659,000. Assuming TURN's forecast of CSRs, PG&E's forecast of CSR training costs would be correspondingly reduced (MWC DK).

Discussion

We grant PG&E's funding request to add CSR supervision and support based on a ratio of 14.5 CSRs for every supervisor (at a cost of $109,861 per supervisor). We adjust PG&E's 2014 forecast amount by $181,839 to reflect our adopted headcount of 991 CSRs (reduced from PG&E's 1,020 headcount). PG&E's forecast for additional CSR supervisors in 2014 is supported by the BCG benchmarking findings. Although PG&E did not add supervisors in 2012 due to budgetary constraints, PG&E did increase the number of supervisors from 2007 to 2011. One-year variations in the ratio of CSR supervisors to staff do not

measure the appropriate level of supervision going forward as a necessary component of safe and reliable customer service.

The BCG Report ranked PG&E's CSR agent-to supervisor ratio higher than the average utilities in 2012. PG&E supervisors were thus managing more employees than the average utility in the benchmark survey. PG&E's additional forecast supervisors will thus improve PG&E's supervisor ratio relative to the industry. This funding of supervision support will enable PG&E to address BCG's industry benchmarking findings of gaps in PG&E's CSR skills relating to customer service, problem solving, and communication style.

5.2.5. Staff Additions to the Customer Advocacy Team (CAT)

PG&E seeks $1.77 million to add 19 CSRs and one supervisor to the Contact Center CAT. PG&E created the CAT in 2011 to address complex, unusual, and/or sensitive customer service issues to speed their resolution and avoid escalation to a formal complaint. PG&E claims that expanding the number of CAT CSRs from 11 to 30 by 2014 is needed to provide assistance on customer issues and make contact with all customers that complete the post call survey with a score of fair or poor.

TURN's recommends that PG&E's 2014 Customer Inquiry Assistance forecast be reduced by $1.77 million to exclude the additional 19 CSRs and one supervisor for the CAT. TURN argues that the CAT can already close nearly all intervention cases at current staff levels. PG&E's request would nearly triple the number of CSRs to handle the 7% of intervention cases unresolved at current staff levels. TURN argues that there is no evidence that 19 new CSRs are necessary to resolve all intervention cases. PG&E argues that CAT's core

purpose is not limited to intervention cases, but also includes post call survey outreach.

TURN argues that the CAT helps PG&E avoid unflattering media attention and intervention by the Commission by helping a small minority of potentially vocal customers feel better about PG&E. The CAT is also charged with contacting customers who rate their Post Call Survey experience on a scale of 1 to 5 as being less than 2. PG&E denies TURN's claims that the purpose of CAT expansion is image building.

TURN claims that PG&E has not shown that 19 additional CSRs are necessary to reach resolution of all intervention cases. PG&E responds that CAT's core purpose is not limited to intervention cases, but also includes post call survey outreach for those customers who rate their CSR experience a 2 or less on a post-call survey. Due to limited resources, CAT was unable to conduct the post-call survey outreach to over half of the customers who ranked their experience a 2 or less in 2011. PG&E's forecast will allow the CAT team to resolve complex customer issues through proactive post-call outreach.

Discussion

We decline to adopt PG&E's forecast of $1.7 million in incremental 2014 expenses for the CAT. Based on existing funding levels, the CAT is already capable of closing nearly all of its intervention cases. We recognize that the CAT's core purpose is not limited to intervention, but includes post-call survey outreach. Expanding the CAT from 11 to 30 CSRs is also expected to reach the 7% of unresolved intervention cases and to reach twice as many customers that rate service negatively in post call surveys. The BCG Report indicated that gaps exist in caller experience and customer follow up including ineffective identification and management of dissatisfied customers across call type, caller

experience and demographic. The additional funding would enable PG&E to conduct post-call survey outreach to customers who ranked their customer service experience poorly.

We realize that PG&E's plans for additional CAT funding provide the potential for some improvement in overall customer perception of PG&E's service level. We also believe that such improvement in customer perception improve PG&E's corporate image which is of benefit to shareholders. In any event, in view of other higher priority expenditures at issue in this GRC, we decline to approve the $1.7 million increase sought by PG&E for the CAT. Also, funding increases for other Customer Care activities help to reduce the overall level of dissatisfied customers without new CAT funding. We find insufficient basis to conclude that the claimed benefits justify burdening ratepayers with the costs of hiring 19 CSRs and one supervisor to expand outreach to customers that provide poor post-call survey ratings.

5.2.6. Average Handle Time (AHT) Increase

PG&E forecasts $11.2 million over 2011 levels (for an increase of 129 CSRs) to maintain current AHT for customer phone inquiries. PG&E presented a five-year trend analysis to show that AHT has increased an average of 4.1% annually. DRA opposes this requested increase, arguing that there is no direct correlation between CSR labor costs and AHT.

DRA relies on 2012 actual AHT data, which was 5 seconds less than PG&E's forecasted 2012 AHT, which shows a reduction in the volume of CSR-handled calls in 2012 as compared to 2011.

PG&E responds that call complexity is increasing due to various factors including new time-of-use rates, payment arrangement discussions, and the increased use of self-service options for less complex issues. PG&E claims that

increasing call complexity increases the AHT. PG&E claims there without funding for the additional CSRs, wait time to speak to a CSR will increase.

Discussion

We adopt PG&E's forecast for $11.2 million to maintain adequate service levels for the average time involved in a CSR's handling of customer call. We recognize that there is not a direct correlation between AHT and total CSR-related costs. Over time, however, the ability to reduce AHT should be enhanced by having more CSR resources. In view of the inherent year-to-year variations in AHT in relation to CSR costs, use of a five-year trend of historical data offers a reasonable approach to normalizing these variations. This five-year trend indicates that AHT has increased 4.1% annually based on this five-year trend. We recognize that this increase in AHT represents a decline in customer service quality. We conclude that increased CSR staffing requested by PG&E is warranted to provide resources to offset this growing duration in AHT and to thereby maintain an acceptable level of customer service. We thus approve PG&E's forecast of $11.2 million to hire an additional 129 CSRs.

5.2.7. Repeat Call Reduction Savings

PG&E forecasts $2 million of repeat call reduction savings driven by forecast customer service improvements including additional self-service options and expansion of the CAT. DRA recommends a lower savings amount of $1.7 million based on its reliance on 2012 call volume.

Discussion

We adopt PG&E's forecast for repeat call reduction savings. We conclude that the selective use of 2012 call volume data is not appropriate. PG&E's call volume forecast is consistent with the five-year historical average of

CSR-handled calls since 2007. Accordingly, we find PG&E's $2 million repeat call reduction savings forecast to be reasonable.

5.3. Office Services

PG&E forecasts $34.189 million in 2014 expenses for Office Services (MWCs DK, EZ and IU), representing an 18% increase over 2011 levels. Office Services include customer payment processing and handling other customer service inquiries available at 75 local offices throughout PG&E's service area. Office Services provide a venue for customers to interact in-person. PG&E attributes the cost increases to labor escalation, additional CSR hirings, and building improvements. DRA proposes $2.6 million in reductions to PG&E's forecast.

5.3.1. CSR Local Office Staffing

PG&E forecasts increased 2014 expense of $1.085 million to hire 10 CSRs to reduce excessive customer wait times to transact business as currently experienced at certain local offices. PG&E proposes to utilize the 10 CSR positions in local offices where wait times are the longest and the number of transactions processed is higher. DRA recommends no increase in Office Services expense forecast associated with the addition of 10 CSRs.

Discussion

We decline to approve PG&E's forecast of $1.1 million to hire 10 CSRs. We recognize that during peak periods, some customers have waited an average of 10 minutes to speak to a CSR, with some wait times approaching 45 minutes. We are not persuaded, however, that PG&E has justified imposing additional costs on ratepayers to address this problem. Our conclusion is based on the following considerations.

PG&E similarly claimed it needed funding for 11 new CSR positions in the 2011 GRC to address increased customer walk-ins to its local offices. While claiming such a need for more staff, however, PG&E actually reduced CSR staff from 2008-2011 by 26 positions. PG&E explains these past reductions of staffing by arguing that adopted revenue requirements in the 2007 or 2011 GRCs were below what PG&E originally requested. PG&E thus redirected funds to other activities deemed to have higher priority.

PG&E could again choose to postpone hiring the requested CSRs during the current GRC cycle, if authorized funding is less than what PG&E believes it needs. PG&E could again redirect funding authorized for CSR positions to pay for other activities deemed to have higher priority. In view of the cumulative cost burden on ratepayers from other increases being adopted in this decision, we question whether funding PG&E's request a second time is justified here.

We also conclude that continuing declines in customers' use of local offices could help mitigate longer waiting lines at least to some extent without new CSR funding. During 2007-2012, PG&E heavily marketed alternatives to local office payments in an effort to move customers to lower cost payment channels such as self-service kiosks, Neighborhood Payment Centers and on-line payments. Such efforts presumably helped reduce the volume of customer walk-ins and mitigated customers' waiting times. PG&E doesn't indicate, however, that such heavy marketing efforts continued after 2012. While some customers will need to or choose to pay their bills at PG&E's local offices rather than through electronic or other payment options, we are not convinced that customers' declining use of local offices for bill payment has plateaued.

We also question whether PG&E has made optimal use of CSRs already employed in its local offices to mitigate excessive waiting lines. As noted by

DRA, PG&E provided no evidence to show that local offices were fully staffed on those days when customer wait times were the longest. PG&E does not have information on whether an employees' shift was covered by another employee that is absent for various reasons.[53] We recognize, of course, that PG&E's offices cannot always be staffed at 100% levels, but experience routine CSR absences such as sick days, vacations, and trainings, etc. Even after taking into account the necessity for such routine absences, however, we question whether productive CSR staffing resources available, particularly on peak days, are utilized in an optimal manner to avoid unacceptable wait times at local offices.

In view of these multiple considerations, we find insufficient justification to impose costs on ratepayers for the additional 10 CSR positions requested by PG&E. To the extent that PG&E finds that new CSR hirings and/or additional overtime for existing CSRs become necessary to avoid excessive customer wait times at local offices despite optimal use of productive CSRs, PG&E should draw on embedded funds and/or reprioritize spending, as necessary.

5.3.2. Local Office Facilities Improvements

PG&E forecasts $1.487 million in expenses (MWC DK, EZ, and IU) and $3.88 million in 2014 capital expenditures for local office facility improvements including relocations and remodels, lobby upgrades, workstation ergonomic improvements, and improved signage. PG&E claims six local offices require remodeling and six more require relocation, with work to be completed over a three-year period. PG&E also requests funds for ergonomic workstation installations.

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[53] Ex. PG&E -20 at A-5.

PG&E claims the building modifications to improve customer access and enhance employee safety. The forecast includes costs to remodel, relocate, install ergonomic workstations, and improve signage at the local offices to better serve customers and promote efficiency, accessibility, and employee and customer safety.

DRA recommends denial of PG&E's funding request for expenses and capital expenditures for the office remodel and relocation increases. PG&E previously requested funding for similar office remodel and relocation work in the 2011 GRC, but deferred the work until this GRC. DRA argues that PG&E has not met the requirements of D.11-05-018 (PG&E's 2011 GRC), directing PG&E to justify such deferrals, and any higher-priority projects that were not identified in the 2011 GRC. DRA claims that PG&E failed to adequately explain its reprioritization process relating to local office upgrades, and failed to justify the deferral, or explain why the upgrades are needed now when they were previously deferred. DRA claims that PG&E can use embedded funding to support any needed improvements to the local offices.

PG&E claims it has provided the requisite justifications called for in D.11-05-018. PG&E explains it did not receive authorization for the full amount requested for its 2011 revenue requirement, and that resource constraints delayed spending on office improvements. PG&E explains that the Commission did not authorize PG&E's total forecasted funding request in the 2011 GRC. As a result, PG&E claims it lacked sufficient funds to complete the office facilities improvements. Thus, PG&E requests ratepayer funding again, arguing that there is still a need to improve the identified office space. Since deferral of the upgrades resulted in further degradation and wear and tear on the local offices, PG&E claims that the upgrades are needed now even more than in 2011.

Discussion

We are not convinced that PG&E's requested funding of $1.487 million for office facilities improvements has been justified. We recognize that a large portion of the local offices reside in facilities constructed decades ago, and have since had minimal upgrades or improvements. Although the improvements would provide certain benefits to PG&E employees and customers, the appropriate context for evaluating the proposed funding is in terms of its relative priority compared with other funding demands.

PG&E requested similar funding for office improvements in the 2011 GRC, claiming the improvements were warranted at that time. Yet, PG&E subsequently postponed these improvements presumably without jeopardizing service quality. PG&E did not consider the office improvements of sufficient priority to implement at that time despite claims in the 2011 GRC that the improvements were needed. PG&E claims that resource constraints necessarily delayed the office improvements work, and claims it is circular reasoning to conclude that deferring work signifies that the work is not necessary.

We recognize that PG&E's prior decision to defer this work does not, in itself, prove that the work is now unnecessary or of no benefit. PG&E's decision to defer this project in the 2011 GRC cycle, however, does reveal PG&E's perception of the project's relative priority at that time as it affected both customer service and shareholder earnings. PG&E's prior action does provide useful context in evaluating the relative priority of the current proposal in the relation to the other large cost increases and higher priority projects that ratepayers are now being asked to bear.

PG&E claims that the level of reduced 2011 GRC funding justified its deferral of the local facilities improvements earlier. Although the 2011 GRC

adopted revenue requirement did not equal 100% of what PG&E initially requested, some increase was adopted. In adopting the 2011 GRC revenue requirement in D.11-05-018, at 28, we stated:

> With respect to reprioritization and deferred cost issues in this GRC, the Settlement Agreement does not indicate specific outcomes; however it is assumed that the settled position reasonably reflects Commission precedents as noted above, taking into consideration the strengths and weaknesses of parties' positions.

In any event, the adopted 2011 GRC increases (which were part of a settlement supported by PG&E) were found sufficient by the Commission for PG&E to provide appropriate service. Yet, given the impact on shareholder earnings, PG&E didn't find the office improvements of sufficient priority to implement despite claimed benefits to PG&E employees and customers. For the current GRC cycle, PG&E has not convinced us, that this funding request has finally reached a sufficient priority to burden ratepayers in this GRC cycle. We make this judgment particularly given the funding previously authorized and in view of other high priority spending adopted in this decision. We thus decline to approve the requested increase in expense and capital funding for local facilities improvements. To the extent that PG&E still believes that these office facility improvements are of sufficient priority to require implementation during the 2014 GRC cycle, PG&E can draw on embedded funds and/or reprioritize spending as necessary to maintain adequate service levels.

5.3.3. Compliance Auditor

PG&E forecasts $0.1 million for an additional compliance auditor to annually audit 100% of the 75 local offices, and to expand the scope of the compliance audit to include additional monetary controls.

DRA recommends a $0.06 million reduction to PG&E's forecast for the additional compliance auditor. DRA's recommendation is based on PG&E's 2011 audit completion rate of 69% of the 75 local offices. DRA asserts that PG&E does not need an additional full-time auditor to complete 100% of the 75 local offices.

Discussion

We adopt PG&E's forecast for an additional compliance auditor as reasonable. PG&E's auditor(s) will have additional audit responsibilities in 2014 as compared to 2011, such as monitoring processes associated with the SMOOP and implementing additional cash management controls. DRA's recommended reduction fails to consider these additional auditor responsibilities for 2014.

5.4. Meter to Cash

5.4.1. Introduction

PG&E MTC Program includes (1) pre-billing activities related to data validation and exceptions processing; (2) bill calculation and maintenance of accurate billings, (3) production and mailing of paper customer bills and presentation and processing of electronic bills; (4) audit and correction of billing related to customer-owned streetlights; (5) reporting revenue; and (6) calculation and payment of user taxes and franchise fees to local governments.

PG&E's MTC proposal is for: (1) a 2014 expense forecast of $136.4 million; (2) a forecast of 2014 capital expenditures of $9.0 million, and 2012 capital forecast of $0.6 million; (3) a new methodology to revise PG&E's uncollectibles factor; (4) authorization to adjust customer fees for restoration for non-payment transactions and non-sufficient funds; and (5) a request to close its Service Disconnection Memorandum Account and recover the recorded costs through PG&E's existing annual electric and gas rate true-up processes.

The forecast is $18.8 million over 2011 costs for increased interval data processing and billing work associated with dynamic pricing defaults for business and agricultural customers and to improve the quality of interval data presented through SmartMeter™ technology. The increase is offset by $5.2 million due to SmartMeter™ efficiencies for a net increase of $13.6 million.

DRA recommends reductions of $28.505 million to PG&E's forecast for MTC expenses, removing incremental costs associated with Interval Data Processing, Quality Assurance staffing, SmartMeter™ Opt-Out processing, Net Energy Metering (NEM) Billing and the Streetlight Inventory Project (SLIP). TURN recommends reductions of $27.09 million. Differences between PG&E, DRA, and TURN are summarized in Table 5-6 of PG&E's opening brief.

5.4.1.1. Uncontested Proposals

We adopt PG&E's uncontested expense proposals for: (1) adoption of base year 2011 recorded costs in MWCs IS, EZ, IT, and IU; (2) SmartMeter™ benefits; (3) postage increases; (4) bill inserter maintenance costs; (5) consumables savings; (6) postage savings; (7) ten additional credit operations full-time employees; and (8) kiosk maintenance. We adopt PG&E's 2014 forecasts for these undisputed activities in the amount of $104.5 million. We also adopt PG&E's proposal to close the Meter Reading Cost Balancing Accounts (MRCBA), consistent with PG&E's 2011 GRC D.11-05-018, which limited the MRCBAs term to the 2011 GRC cycle only.

We also adopt the PG&E request for authorization to close its Service Disconnection Memorandum Account on December 31, 2013, and recover recorded costs through its existing annual electric and gas rate true-up processes. In the Service Disconnection Rulemaking and related decisions, the Commission directed PG&E to track in memorandum accounts its compliance costs associated

with implementing new service disconnection practices. The Commission ordered that the utilities address memorandum account cost recovery in each utility's next GRC. Consistent with that direction, PG&E seeks approval to close the Service Disconnection Memorandum Account and to recover the recorded amounts through the annual electric and gas rate true-up processes. No party opposes PG&E's request.

5.4.2. Hourly Interval Energy Usage Data Processing

PG&E forecasts $18.8 million in expense for additional staffing to process the increased volume of energy usage data exceptions resulting from hourly interval energy usage data that is now available to customers through the SmartMeter™ technology.

SmartMeter™ technology provides residential customers with access to hourly interval energy usage data. PG&E's MyEnergy website offers customers access to their hourly interval energy usage data to make better informed decisions to help manage their energy usage and energy bills. Customers previously had only after-the-fact access to their monthly energy usage data, as collected manually by meter readers.

PG&E claims the additional staff is required to ensure that the interval energy usage data provided to customers via website presentation and for billing purposes is accurate. PG&E claims that the volume of energy usage data collected for each customer has grown from a single monthly read to between 675 and 3,200 interval reads per month. PG&E thus claims that the additional staffing is required to process this increased volume of data exceptions.

DRA forecasts a decrease of $5.2 million below 2011 levels. DRA argues that providing accurate hourly interval energy usage data to residential

customers is premature because the Commission has not yet approved Time of Use (TOU) or Dynamic Pricing for all residential customers. DRA acknowledges that interval data exceptions processing is necessary for customers whose billing requires the use of interval data. DRA claims such processing of hourly interval energy usage data exceptions for all SmartMeter™ customers is unnecessary, however, in the absence of default rates requiring interval data. DRA also claims that the quality of interval data presented to customers on MyEnergy for non-billing purposes is adequate.

PG&E argues that the 2010 Rate Design Window (RDW)/PTR proceeding is currently pending and will default all residential customers to time-varying, interval based billing. PG&E argues the Commission will in any event likely approve large-scale residential default some time during the 2014 GRC cycle. PG&E contends that it will need to have resources in place to provide accurate interval billing on a large scale. PG&E claims that customers who will transition to TOU or Dynamic Pricing in the future would benefit now from having access to accurate hourly energy usage data on the web to help better understand their energy usage patterns and better manage their energy bills once the Commission mandates time-varying pricing for residential customers.

TURN likewise argues that PG&E has not demonstrated that the proposed $18.8 million funding is justified or will provide new capabilities or significant benefits compared to the status quo. TURN argues that billing quality data is not necessary for customers to make informed choices regarding energy use in response to website information. TURN believes there is little reason to ensure billing quality data presentation on PG&E's website when less than 1% of customers regularly use these data. While the website presents a graphs and charts showing customers their usage on an hourly, daily and monthly basis,

DRA and TURN claim this as a nonessential product for customers not currently on interval billing.

TURN also argues that PG&E's proposed funding duplicates prior funding provided as part of the SmartMeter™ deployment proceeding. PG&E denies that prior authorizations in D.12-11-051, the Advanced Metering Infrastructure (AMI) decision included funding for staff to process interval data exceptions.

TURN questions PG&E's explanation that its funding request in the AMI application did not include money to process data exceptions so as to produce billing-quality data. TURN claims that PG&E either had misled the Commission, or else simply forgot to request all the money necessary to actually achieve the functionality of the AMI system.

At a minimum, TURN proposes rejection of the $12.0 million portion to process data exceptions for residential customers not currently on an interval billing rate, arguing there is no need to provide billing-quality data for customers to make use of the information on their "My Account" website.

Discussion

We adopt a reduction to PG&E's forecast for additional staffing to process the increased volume of energy usage data exceptions resulting from hourly interval energy usage data available to customers through the SmartMeter™ technology. We reduce PG&E's forecast by $12 million relating to processing of data exceptions for residential customers not currently on an interval billing rate. We agree with TURN's assessment that there is no need to provide billing-quality data for customers to make use of the information on their "My Account" website. The procedural timing of the 2010 RDW/PTR proceeding remains uncertain, and we find insufficient basis to presume the outcome of that proceeding for purposes of PG&E's proposal here. We conclude that PG&E has

not previously been granted funding for this activity in the SmartMeter™ Deployment proceeding.

5.4.3. Relocation of Departments to New Facility

PG&E forecasts $1.5 million in 2014 expenses and $9.011 million in 2014 capital expenditures to relocate two MTC departments, its Billing Operations and Credit Operations groups, to a new leased facility in Stockton. PG&E claims the relocation of these two groups is necessary due to deficiencies in the existing facility including inadequate space for staff and the inability to accommodate increased staffing relating to Interval Data Processing and Quality Assurance increases.

The departments would relocate to the larger upgraded facility at the expiration of the existing facility's lease in 2014. PG&E claims the existing facility in Stockton is over capacity with just the staff currently assigned there and additional staffing will be required in 2014.

DRA and TURN oppose approval of PG&E's requested relocation expenses and capital expenditures, arguing that relocation of the Billing and Credit Operations groups to accommodate increased staffing is unnecessary. They oppose PG&E's forecast increased staffing levels. PG&E argues, however, that its proposed relocation is based solely on forecasted staffing increases, but also on other factors, including inadequacy of space for existing staff, future maintenance costs, and inadequate employee parking and safety.

DRA opposes any funding for the proposed relocation as unnecessary since DRA rejects PG&E's proposed staffing increases in the Billing and Credit Operations Departments. DRA also argues that no funding is required for the relocation of the Billing and Credit Operations Departments.

PG&E has reduced staffing from other departments to allow for increased Billing and Credit Operations staffing in its Stockton facility. Additionally, PG&E has increased staffing for billing and Credit Operations in a Concord facility.

Discussion

We adopt PG&E's forecast of $1.5 million in 2014 expenses and $9.011 million in 2014 capital expenditures to relocate two MTC departments, its Billing Operations and Credit Operations groups, to a new leased facility in Stockton. We conclude that the expenditures are justified based on a variety of factors beyond the impact of planned increases in employee levels.

The Stockton facility has inadequate space to accommodate the density of existing employees working there based on benchmarking standards published by the U.S. General Services Administration. The Stockton facility also lacks adequate parking facilities. Lack of adequate parking creates safety issues for employees who must walk long distances outside of the facility to find parking. The new facility will rectify the parking deficiencies, thereby promoting a safer working environment.

5.4.4. Uncollectibles Mechanism

PG&E recommends the adoption of a revised mechanism that addresses: (i) more timely customer uncollectibles management through times of economic volatility; and (ii) increased utility bill payment and credit policy flexibility in order to assist customers experiencing difficulty in paying their energy bills. Specifically, PG&E proposes that the uncollectible factor be determined based on a rolling five-year average that adjusts annually. In order that the five-year uncollectibles average be as current as practicable, PG&E recommends that this average lag the current year by only one-year. As an example, the average

uncollectibles for the period of 2007-2011 would be the average used and applied to 2013 performance and rates. If this mechanism were in place for 2013, this factor would be 0.003531 based on data from 2007 through 2011. Changes in the base factor (up or down) would be built into rates via an annual advice filing. PG&E's proposed mechanism results in a factor of 0.00376, or 21% above its current factor.

TURN supports use of a rolling average and true-up on an annual basis, but recommends using a 10-year as opposed to a five-year average as proposed by PG&E. PG&E believes a 10-year average is too long to timely reflect changes in current economic conditions.

DRA also proposes use of a 10-year averaging of write-off amounts, divided by revenue, with the highest and lowest values for write-off amounts within the 10 years removed from the calculation. Under DRA's proposal, the write-off factor would be applied to all years within the GRC cycle as a fixed value. DRA claims that its proposal incorporates a longer historical time range to smooth the variable of economic conditions in contrast to PG&E's approach which places greater weight on the 2008-11economic downturn.

PG&E claims that DRA's proposal is not much different than the current mechanism and fails to address the deficiency inherent in the current mechanism (i.e., the inability to timely respond to changing economic conditions).

Discussion

We adopt the revised methodology to determine PG&Es uncollectible factor as proposed by TURN. The adopted methodology will produce an uncollectible factor of 0.003257 for test year 2014 based on a 10-year rolling average of 2003-2012 data. The uncollectible factor will be revised annually thereafter by advice letter filing using updated historical data. For example, the

2015 uncollectible factor will be based upon an average of 2004-2013 data. We conclude that annual updating in this manner will provide more timely reflection of changing economic conditions relative to the traditional approach whereby a single uncollectible factor is fixed for the entire GRC cycle.

We conclude that TURN's proposal provides advantages similar to those offered in PG&E's proposal, while incorporating a more appropriate rolling average time period. TURN's approach incorporates the best elements of PG&E's and DRA's proposals. PG&E's proposal, based on a five-year rolling average, would produce a factor of 0.003757. TURN's proposal differs by incorporating a 10-year rolling average. We conclude that a 10-year average offers a more reasonable time horizon in calculating the uncollectible factor. A 10-year average better reflects normalized test year conditions without assigning excessive weight to shorter-term fluctuations in economic conditions. Use of a five-year average would unduly inflate the calculation with data from a period marked by (1) nearly unprecedented conditions endured by PG&E customers and (2) the Commission's extensive intervention in the utility's credit and collection policies in response, starting in 2010.

5.4.5. Customer Payment Channels

PG&E's expense forecast includes $3.8 million to provide customers with expanded Customer Payment Channels including expanded electronic billing and payment options, the pay-by-phone option, staff to support electronic payment options, and marketing of new payment options. DRA recommends a $2.7 million reduction for: (1) Electronic Payment Volumes; (2) Pay-by-Phone Costs; (3) Electronic Payment Channel Staff; and (4) Electronic Payment Channel Marketing.

Discussion

We adopt PG&E's forecast as reasonable, and decline to adopt DRA's proposed reductions. DRA recommends a reduction of $0.1 million in electronic payment expenses assuming that electronic payment volumes (and associated costs) will remain flat relative to 2012. We conclude, however, that electronic payment volume in 2014 will increase based on the new one-time electronic payment option, and new online billing and payment functionality added in 2013. DRA recommends a $0.54 million reduction for Pay-by-Phone costs assuming that Pay-by-Phone customer assistance costs are linked to mobile payments. Yet, the two payment channels are distinctly different. Thus, DRA's proposed reduction is based on an erroneously derived ratio.

DRA's opposition to funding of additional positions for expansion of electronic pay channels for customers assumes that PG&E has embedded funding for the additional positions because they were part of the previously dispersed staffing that formed the new Pay Channel group. The costs associated with the previously dispersed employees are reflected in 2011 recorded costs for the new Pay Channel group. PG&E's $0.3 million forecast is for incremental positions necessary to support expansion of electronic payment channels for customers.

5.4.6. Quality Assurance Staffing

PG&E forecasts Quality Assurance Staffing expense forecast of $0.6 million to hire additional Billing Operations (four positions) and Revenue Operations (two positions) staff to ensure that the employees in these two organizations receive the necessary training and oversight to perform their jobs and meet all regulatory and internal compliance requirements.

DRA opposes PG&E's request for incremental staff, alleging that PG&E has received funding for this work. PG&E responds that large-scale interval billing is a new function introduced with the deployment of SmartMeter™ technology and the Commission's recent decision to default small and medium business (SMB) customers to time-varying pricing.

Discussion

We adopt PG&E's forecast. We conclude that the forecasted funding will provide appropriate training to ensure employees correctly perform their job duties. PG&E's incremental staffing forecast is for a new function primarily driven by new and increased processing of interval data and interval-based billing. The quality assurance and training functions associated with the interval data processing represent new work and necessitate incremental resources.

5.4.7. Revenue Assurance Staffing

PG&E forecasts increased Revenue Assurance Staffing of $1.3 million to identify, investigate, and remediate energy theft. PG&E's Revenue Assurance staff also assists law enforcement officials involved with code enforcement and energy theft associated with illegal activities.

DRA and TURN oppose the $1.3 million Revenue Assurance staffing forecast claiming that increased staffing is not justified based on the recent trend of declining new meter tampering cases. The trend of decreasing new cases in recent years is attributable to the reduction in meter readers who historically visually identified meter anomalies as they walked on their meter routes. PG&E claims that as use of the new SmartMeter™ functionality matures, it is experiencing an increase in meter tampering cases being detected remotely through the SmartMeter™ system.

Discussion

We adopt PG&E's forecast for an increase of 13 field representatives at a cost of $1.3 million for Revenue Assurance. We conclude that PG&E's funding proposal should be granted to address Revenue Assurance issues effectively.

Although DRA and TURN claim that the total number of potential theft cases investigated by Revenue Assurance has been decreasing, the number of reported cases that were not investigated actually increased by 77% between 2008 and 2012 due to insufficient staff. We recognize that meter tampering can involve safety issues.

Revenue Assurance staffing also implicates safety-related issues. With the change in meter technology to SmartMeter™, the preferred methods of energy diversion have increased the potential risk of injury to the public and employees. PG&E has seen more frequent use of "meter bypass" where wiring of loads is made around the meter, internal meter tampering and unauthorized replacement of SmartMeters™. Increased Revenue Assurance staff will help address these unsafe energy diversion practices.

5.4.8. Energy Data Services (EDS) Meter Reading

PG&E forecasts $3.2 million of expense to fund the field retrieval and telephony-based metering for large commercial, industrial, and agricultural customers (approximately 20,000 meters), and also to fund data retrieval associated with load research activities (approximately 6,700 load research sites). PG&E's $3.2 million forecast includes no increase in Energy Data Services costs from 2011 beyond labor and non-labor escalation. The forecast reflects the transition of these EDS costs to the GRC from the meter reading balancing account, which was scheduled to close at the end of 2013. TURN opposes the

$3.2 million forecast, arguing that PG&E originally planned to replace the EDS-read meters with SmartMeters™. In A.05-06-028, PG&E had estimated billing and meter reading savings from replacing these meters.[54] TURN argues that PG&E subsequently reduced its SmartMeter Deployment costs by not deploying SmartMeters to the large customers served by PG&E's Energy Data Services Group. TURN claims PG&E saved those costs, not through efficiencies, but by reducing the scope of their deployment. TURN argues that PG&E's requested funding of $3.2 million for reading the MV-90 meters effectively reduces forecasted savings.

PG&E's EDS-read meters include two meter types that PG&E explicitly identified to the Commission that it did not intend to upgrade with SmartMeters™: (1) meters for certain Direct Access customers (i.e., customer-owned meters); and (2) non-core gas meters with an electronic corrector. PG&E's EDS meter reading forecast also encompasses a subset of EDS-read electric meter locations that are of such non-traditional service configurations that SmartMeter™ technology is not currently available to serve them (e.g., 4-quadrant meters servicing customers with large co-generation facilities that require measurement of reactive voltage on both consumption and generation channels). PG&E denies that it intended to replace these categories of meters.

PG&E originally planned to replace the 19,967 MV-90 electric meters which are the largest subset of EDS-read meters. PG&E argues, however, that it should not be penalized for exercising its reasonable professional judgment as

[54] Ex. 118, p. 19; Ex. 119, Attachments 9 and 10 (TURN/Nahigian).

part of its obligation to prudently manage the SmartMeter™ deployment. Given the size and scope of PG&E's unprecedented SmartMeter™ project, it is reasonable to assume that a small number of unique metering types would not be upgraded to the current technology.

Discussion

We adopt PG&E's forecast of $3.2 million to fund the field retrieval and telephony-based metering for large commercial, industrial and agricultural customers and to fund data retrieval associated with load research activities. The forecast reflects the transition of these costs from the meter reading balancing account to GRC-funded revenue requirements. TURN claims that PG&E already received the funding to replace the meters in the AMI application and only subsequently changed its mind. We find PG&E's justification for recovering this cost to be reasonable. Although actual benefits may differ than the forecast in its original AMI case, overall SmartMeter™ program benefits reflected in PG&E's Table 10-1 of Exhibit 22 exceed those originally estimated in the AMI case (adjusted for escalation).[55] Approval of PG&E's funding request will ensure the resources to collect energy usage data from this limited set of customers with unique metering needs.

TURN argues that if the Commission authorizes recovery of this cost, PG&E should be directed to allocate this cost to non-residential customers in Phase 2 of this GRC since this represents the costs of the non-residential Opt-Out program. Since cost allocation issues are the subject of the GRC Phase 2, we will take up TURN's cost allocation proposal in that proceeding.

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[55] Exh. 119: Attachments to the Testimony of Jeffrey A. Nahigian, page 37.

5.4.9. Credit Notice Savings

PG&E forecasts $1.5 million of expense savings associated with PG&E's discontinuation of the residential 15-day credit notice, consistent with Commission direction. PG&E's savings forecast reflects savings on postage and material costs on an estimated 3.6 million notices annually.

DRA recommends a $0.4 million increase to PG&E's forecast saving based on an averaging of the historic counts of 15-day notices issued by PG&E in 2011 and 2012.

Discussion

We adopt PG&E's forecast savings. DRA's analysis does not consider the likely increase in 48-hour notices due to changes to the credit follow-up timeline accompanying elimination of the 15-day notice. PG&E's forecast nets the expected 15-day notice savings with a corresponding forecast increase in 48-hour notices.

5.4.10. Net Energy Meter Billing

PG&E forecasts $0.3 million for net energy meter billing to increase staffing to enable PG&E to handle forecasted growth within the NEM customer population.

DRA recommends that the Commission reject PG&E's $0.3 million forecast based on the functionality and timing of PG&E's NEM IT Billing project, and the planned transition of NEM billing work from the Advanced Billing System (ABS) to the Customer Care and Billing (CC&B) Operations Exceptions department.

Discussion

We adopt PG&E's forecast as reasonable. The transition of NEM accounts to CC&B is not expected to occur before the end of the $0.8 million reduction to

PG&E's SmartMeter™ Opt-Out Processing forecast or $0 incremental funding recoverable as part of PG&E's GRC revenue requirement for 2014.

Also, the scope of the NEM IT project does not apply to all NEM billing tariffs, but only to the subset of NEM residential customers on rate schedules E1, E6 and E7. Commercial NEM tariffs and all Virtual-NEM billing accounts, comprising approximately 15% of the current NEM population, will still be billed in PG&E's ABS. Given the limited scope of the NEM IT Project and timing of the transition of NEM accounts to CC&B, we conclude that PG&E's $0.3 million staffing forecast is reasonable to handle NEM accounts in Customer Billing.

5.4.11. Streetlight Inventory Project

PG&E forecasts an increase of $0.4 million to support field audits of streetlights in its service area to ensure that PG&E's billing records are complete and accurately reflect the equipment in service on the distribution system described as the Streetlight Inventory Project (SLIP). Both DRA and the CCSF recommend no increased funding for the SLIP.

DRA claims that the SLIP costs are embedded within other MWCs in PG&E's GRC forecast. PG&E responds that it added all 2011 base year recorded costs associated with SLIP to MWC IS and subtracted such costs from the MWCs to which they were originally charged. CCSF argues that PG&E has not demonstrated a need for any incremental streetlight auditor positions beyond those funded in the 2011 GRC.

Discussion

We adopt PG&E's forecast for the SLIP as reasonable. We recognize that the SLIP and the Streetlight Management Program included in PG&E's 2011 GRC forecast are two distinct programs that are not the same.

Funding for the Streetlight Management Program is for distinct activities (e.g., coordinating development of new rate schedules for energy efficient streetlights) unrelated to the tariff- required SLIP, which inventories customer-owned and utility-owned streetlights. PG&E thus does not have embedded funding for SLIP based on the 2011 GRC forecast for the Streetlight Management Program. We conclude that PG&E's SLIP forecast for 2014 is reasonable to enable PG&E to complete the inventory project throughout PG&E's service area.

5.4.12. SmartMeter™ Opt-Out Processing

PG&E forecasts an increase of $0.8 million for staffing to support the Billing Operations processes to fulfill customer requests to participate in the Commission-approved SMOOP. DRA recommends a one-way balancing account for all SMOOP related expenses, capital expenditure and revenues. As part of its balancing account proposal, DRA recommends a cost cap, resulting in a reduction of $0.6 million to PG&E's Opt-Out customer enrollment and billing forecast.

TURN does not oppose PG&E's expense forecast for incremental SmartMeter™ Opt- Out processing. DRA's recommended reduction is based on a lower SmartMeter™ Opt-Out participation forecast of 54,061 Opt-Out customers, as compared to PG&E's forecast of 200,670 customers. Given the uncertainty in Phase 2 of the SmartMeter™ Opt-Out proceeding around a Community Opt-Out option and the level of Opt-Out fees, PG&E argues that its forecast should be adopted to ensure that has resources available to timely process Opt-Out requests in 2014.

Discussion

We adopt PG&E's forecasted increase of $0.8 million to ensure adequate resources to timely process Opt-Out requests. We address balancing account proposals relating to PG&E's SmartMeter™ Opt-Out Program in Section 5.5.1.1.

5.4.13. SmartMeter™ Opt-Out Field Collection

PG&E forecasts expenses of $2.1 million to conduct in-field service disconnections (referred to as Shut-Off Non-Payment or SONP) due to non-payment of a bill once all attempts to collect payment have been exhausted. The in-field service disconnections are required when no SmartMeter™ is installed and, therefore no automated remote shut-off functionality is available. PG&E's expense forecast for this activity is due to the population of analog meters (primarily Opt-Out Program customers) that will remain after SmartMeter™ deployment is completed.

TURN recommends a $1.5 million reduction to PG&E's expense forecast for SmartMeter™ Opt-Out field collection. TURN's forecast is based on an assumed lower population of Opt-Out participants (40,000), as compared to PG&E's forecasted Opt-Out participation rate (200,670). Due to the uncertainty in the outcome of Phase 2 of the SmartMeter™ Opt-Out proceeding, PG&E claims that its forecast will ensure sufficient resources are available to conduct in-field disconnections at the premises of Opt-Out customers.

Discussion

We adopt TURN's recommendation for a $1.5 million reduction to PG&E's expense forecast for SmartMeter™ Opt-Out field collection. TURN's forecast is based on an assumed lower population of Opt-Out participants (40,000). Our basis for adopting TURN's figure is discussed in further detail in Section 5.5 below.

5.4.14. Risk Analysis Software (MWC IT)

PG&E forecasts $300,000 for Customer Risk Analysis Software to help its Credit Operations identify the highest risk customers, prioritize collections activities and minimize bad debt. The software can better identify customers for outreach efforts ahead of credit notification and service disconnection. PG&E claims the software can be used to identify customers who are experiencing difficulty in paying their bill and may qualify for financial assistance.

TURN claims that additional ratepayer funding for this program is unnecessary because PG&E already possesses all of the functionality that the software would offer.

TURN claims that the Customer Risk Assessment Software may increase the speed and precision of functions already conducted by that department, but that PG&E has not demonstrated that this investment will provide new capabilities or significant benefits compared to the status quo. Accordingly, TURN proposes reduction of PG&E's MTC 2014 expense by $300,000.

TURN also claims that PG&E already prioritizes collections activities for the highest risk customers. In response to the Commission's directives in Rulemaking 10-02-005, PG&E implemented credit policy changes, including "processes to more effectively prioritize accounts that are scheduled for service disconnections so that accounts with the most significant risk and exposure are completed first." PG&E assigns customers a credit score, and based on the credit score and a customer's payment history, PG&E determines which accounts present the most risk and addresses those first. The Customer Risk Analysis Software would simply automate the prioritization process.

Discussion

We adopt PG&E's forecast of $300,000 for MWC IT.

Although PG&E currently performs certain manual customer risk assessment functions, the forecast Risk Assessment Software will enable enhanced risk assessment modeling and automate existing modeling (as distinct from human processes) to more effectively identify the highest risk customers, prioritize collection activities and minimize bad debt losses. Risk Assessment Software is used by most major companies, including utilities. We conclude that the benefits justify approval funding here.

5.5. Metering

PG&E forecasts $74.7 million in 2014 meter expenses included in MWC AR, DD, EY, and HY. PG&E's metering program is to provide safe and efficient responses to metering-related customer service requests and compliance related work. Two umbrella organizations manage metering functions: (1) Field Meter Operations (FMO), and (2) Meter Asset Management and Engineering (MAME).

Meter expenses are recorded in MWCs: AR Read and Investigate Meters, DC Dispatch Customer Service, DD Provide Field Service, EY Change/Maintain Used Electric Meters, and HY Change/Maintain Used Gas Meters. PG&E forecast 2014 expenses is a 132% increase beyond 2011 recorded expenses. Total DRA proposed reductions are $50.6 million. TURN proposes reductions of $31.4 million. Table 5-9 of PG&E's opening brief itemizes the differences.

PG&E forecasts Metering capital expenditures of $117.0 million for 2012, $128.0 million for 2013, and $128.2 million for 2014. DRA recommends 2012 recorded Metering capital expenditures of $112.1 million, with forecasts for 2013 of $106.8 million and 2014 $110.0 million. Total DRA adjustments to PG&E's forecast are $4.9 million for 2012, $21.2 million for 2013 and $18.1 million for 2014.Table 5-12 of PG&E's opening brief itemizes the differences.

5.5.1. SMOOP Meter Reading

PG&E forecasts $32.038 million in 2014 expenses for MWC AR (Read and Investigate Meters) consisting of: (1) $27.9 million to read meters of residential SmartMeter™ Opt-Out customers, and (2) $4.074 million for non-Opt-Out Program meters requiring manual reads.

DRA recommends a $31 million reduction to PG&E's 2014 expense forecast for Opt-Out meter reading. TURN recommends a $26.5 million reduction.

PG&E's meter reading expense forecast is based on the number of customers forecast to participate in the SMOOP in 2014 (200,670) multiplied by the forecast unit cost per *premise* to read the meters ($11.60). DRA and TURN disagree with PG&E's 2014 Opt-Out Program customer participation forecast of 200,670 customers (approximately 384,000 meters). DRA's forecast of Opt-Out Program participants is 54,061 customers (approximately 90,000 meters). TURN's forecast is 40,000 participants (approximately 66,000 meters). DRA accepts PG&E's $11.60 per premise meter reading unit cost but TURN does not.

PG&E argues that its Opt-Out participant forecast is reasonable based on the uncertainty associated with the Phase 2 Opt-Out proceeding. The outcome of that proceeding will affect SMOOP participation and related costs, particularly if the Commission reduces or eliminates the cost of opting-out or authorizes any form of community opt-out. Because these issues remain pending, PG&E argues that its forecast reasonably reflects the potential increase in Opt-Out participation that may result if, for example, the Commission authorizes a Community Opt-Out option. If the Commission does not issue a decision in Phase 2 of the Opt-Out proceeding in time for incorporation into this GRC, PG&E proposes a two-way balancing account to manage the uncertainty.

5.5.1.1. Balancing Account Proposals

In view of the uncertainty in the absence of a Commission decision in the Phase 2 Opt-Out proceeding, PG&E supports use of a two-way balancing account mechanism if the Commission does not issue a Phase 2 Opt-Out decision in time to incorporate into this GRC. PG&E argues that a two-way balancing account will ensure adequate resources to accommodate demand while ensuring recovery in rates of only the amount needed to implement the Opt-Out Program.

DRA recommends a one-way balancing account cover for PG&E's SmartMeter™ Opt-Out Program-related expenses, capital expenditures, and revenues, rather than including them in the 2014 GRC revenue requirement. DRA proposes $3.1 million for remaining manual reads. DRA expects IT updates, and the SmartMeter™ project being fully deployed, to help resolve issues and reduce the number of meters requiring manual reads. DRA argues that any balancing account should be one-way with no provision for PG&E to recover actual costs above adopted estimates.

PG&E opposes DRA's proposed one-way balancing account with cost caps, arguing that a one-way balancing account fails to address the uncertainty, and exposes PG&E and its customers to the risk of inadequate funding by shifting the cost burden to PG&E's shareholders. Without proper GRC-funding, PG&E claims it may not be able to address the increase in Opt-Out participation that could result from the Commission's Phase 2 decision.

Discussion

We also adopt PG&E's proposal for use of a two-way balancing account as the fairest and most effective way to address and resolve the uncertainty regarding the outcome of the Opt-Out proceeding. DRA's proposal for a one-way balancing account does not mitigate the uncertainty of increased or

decreased costs and revenues. If Commission approves a community Opt-Out option, Opt-Out participation (and related costs) could exceed DRA's and TURN's forecast number of Opt-Out participants, and even exceed PG&E's Opt-Out related forecasts. To the extent that subsequent Opt-Out meter reading costs differ from our adopted forecast, the two-way balancing account will provide an appropriate vehicle to adjust PG&E's recovery of costs accordingly.

5.5.1.2. Forecast Number of Opt-Out Customers

PG&E developed its Opt-Out Program meter reading expense forecast by multiplying the number of customers forecast to participate in the SMOOP in 2014 (200,670 customer s and 384,000 meters) by the forecast unit cost per *premise* to read the meters ($11.60). DRA and TURN disagree with PG&E's 2014 Opt-Out Program customer participation forecast. DRA and TURN each forecast a lower number of Opt-Out Program participants than PG&E, which results in a lower forecast for Opt-Out meter reading expenses. DRA's forecast is 54,061 customers (approximately 90,000 meters). TURN's forecast is 40,000 participants (approximately 66,000 meters). TURN recommends a $24 million expense reduction.

PG&E's Opt-Out participant forecast count is based on the uncertainty associated with the pending Phase 2 Opt-Out proceeding which will address whether Community Opt-Out should be permitted as part of the Opt-Out Program, and whether interim Opt-Out fees should be modified. Because these issues have not yet been decided by the Commission, PG&E's forecast reflects the potential increase in Opt-Out participation that may result.

TURN argues that even if the Commission adopts use of a balancing account, the adopted forecast should still be based on reasonable estimating parameters. TURN claims that PG&E's forecast of SMOOP participation is at

odds with actual participation numbers and PG&E's own forecast of participation in A.11-03-014.

5.5.1.3. Meter Read Unit Cost Per Premise

PG&E's forecasted Opt-Out meter reading unit cost per premise is $11.60. DRA accepts PG&E's $11.60 per premise meter reading unit cost but TURN does not. TURN proposes a forecast of $5.00 per meter read. DRA accepts PG&E's Opt-Out meter reading unit cost per premise of $11.60. TURN opposes PG&E's meter reading unit cost per premise and proposes instead $5.00 per meter. PG&E claims TURN's forecast is based on outdated cost data and fails to take into account recorded data that shows a trend of increasing meter reading costs. In PG&E's Phase 2 Opt-Out proceeding, PG&E forecast a $5.00 meter reading unit cost per meter for 2012, which is the basis of TURN's 2014 meter reading recommendation in this proceeding.

PG&E disputes TURN's forecast claiming that TURN confused the distinction between cost "per premise" versus "per meter," and that TURN's forecast is based on outdated and inappropriate cost data.

Discussion

We reduce PG&E's forecast by $24 million based on use of TURN's unit cost and customer estimates. Reducing PG&E's forecast based on these adjustments offers the most reasonable basis for a 2014 forecast.

We conclude that TURN's estimate of 40,000 SMOOP customers offers the most reasonable assumption for test year purposes. As of April 2013, PG&E had a total of only 33,338 SMOOP customers signed up for the Opt-Out Program. To reach its GRC forecast total, PG&E would have to sign up an additional 166,262 SMOOP customers by January 1, 2014. We agree with TURN that such a large increase in SMOOP participants is unrealistic. Based on the rate of increase

in SMOOP customers over the seven-month period preceding April 2013, PG&E would add only 4,386 new SMOOP customers by January 1, 2014. We thus conclude that TURN's figures indicate that a total of 40,000 opt out customers for the test year is the most reasonable forecast.

We also conclude that TURN's per-unit cost is the most reasonable. We recognize that TURN did not forecast on a 'per premise' basis. However, that fact does not lessen the validity of TURN's forecast. TURN used a "per meter" cost of $5.00, multiplied by TURN's forecast number of meters. PG&E's meter reading unit cost per premise could include multiple meters since many customers have an electric and gas meter at their premise. TURN's meter reading unit cost is "per meter." Both PG&E and TURN multiply the different unit types—i.e., per premise and per meter – by the matching unit cost.

TURN's figure is based on average recorded costs for March through June of 2012. PG&E claims that TURN's figure fails to account for the fact that manual reads become more and more dispersed on the meter-reading routes due to the Opt-Out Program. PG&E claims that the trend of increasing cost per meter-read is already reflected in data from 2011-2012, presented in Table 5-3 of Exhibit 57, and will continue in the future.

TURN agrees that the cost of reading Opt-Out customer meters is reflected in the data. TURN also agrees that meter reads of Opt-Out customers will become more dispersed, but claims this impact is already reflected in the March-June 2012 time period used by TURN. By May 2012, the number of Opt-Out participants had stabilized, and unit meter reading costs likewise stabilize. TURN's forecast of unit meter reading costs, based on the March-June 2012 data, thus includes the relevant time period that meter reading costs for Opt-Out participants increased. Unit meter reading costs are fairly constant after

May 2012, and there is no trend in the unit cost between May and December 2012, once SMOOP numbers stabilize. The average unit cost in May-June 2012 was $5.28. We find insufficient basis to adopt a unit cost above this value.

Although PG&E claims costs will increase because SMOOP customers are dispersed, this dispersion is already reflected in the May-December 2012 data, and explains why unit costs increased after January 2012. We agree that there is no factual basis for concluding that meter reading costs were increasing after May 2012.

PG&E claims that TURN fails to take into account data that shows an increasing trend in meter reading costs. These costs have been increasing, in large part due to the increasingly disperse nature of the remaining meters that need to be read manually as SmartMeter™ deployment nears completion. Based on the trend of increasing meter reading costs, PG&E used a change of party (CP) meter read as the basis for its 2011 recorded unit cost in this GRC, as opposed to a "regular read." PG&E claims that the CP meter reading costs are more reflective of the non-contiguous meter reads to be performed in 2014 for Opt-Out customers.

TURN responds, however, that, a CP request must be timely completed and cannot be scheduled so as to optimize meter reading deployment. It is essentially almost a one-off meter read. This is not true of meter reading of Opt-Out customers. Even though the customers may be dispersed, they will still be scheduled so as to be on the most efficient meter route possible.

5.5.2. Non-Opt-Out Meter Reading

In addition to the population of Opt-Out meters, PG&E identifies two categories of meters that it must manually read: (1) SmartMeters™ that

require temporary manual reads during maintenance, and (2) a small percentage of technically challenged meters that may not connect to the SmartMeter™ network. PG&E refers to these meter reading categories as a "non-opt-out meter reading." Similar to the methodology for calculating Opt-Out meter reading expenses, PG&E developed its forecast of expenses for non-Opt-Out meter reading by multiplying (1) the number of premises requiring meter reading by (2) the forecast unit cost per premise. Both DRA and TURN accept that PG&E will need to read these two categories of meters but they disagree with PG&E's forecast of expenses for that purpose.

PG&E forecasts approximately 230,000 premises to be read manually by approximately 200 meter readers, largely as a result of the SmartMeter™ Opt-Out Program. PG&E forecasts $4.07 million for non-Opt-Out meter reading expense for 2014.

TURN recommends a $2.6 million reduction to PG&E's expense forecast based on its opposition to PG&E's meter reading unit cost, as discussed above. As PG&E's forecast of $11.60 per premise meter reading unit cost is based on recorded meter reading costs and trends. TURN agrees with PG&E on the number of non-Opt-Out meters that will require manual meter reads in 2014. DRA recommends a $3.1 million reduction to PG&E's forecast for non-Opt-Out meter reading expenses.

DRA accepts PG&E's forecast unit cost per premise of $11.60 but disagrees with PG&E's forecast number of meters that require manual reads. DRA disputes the number of meters requiring reads in two categories: SmartMeter™ maintenance meters, and technically challenged meters as discussed below.

PG&E forecasts the total number of maintenance-related meter reads in 2014 to be 213,540, based on its forecast that 71,180 SmartMeters™ will require

maintenance during 2014, and that each of those meters will need to be manually meter read for three months while the maintenance issues are being resolved.

DRA forecasts 65,065 reads per year due to SmartMeter™ maintenance issues.

DRA opposes PG&E's forecast that maintenance meters will require manual meter reading for an average of three months while the issue is investigated and repaired. DRA believes that one month should be sufficient time for PG&E to remediate communication errors. PG&E's recorded data from 2010-2012 illustrates that SmartMeters™ that developed maintenance issues were, on average, manually read for 61 business days while the maintenance issues were addressed. Given that there is an average of 22 business days in a month, the 61 days equates to an average of three months.

DRA's estimate of SmartMeter™ maintenance meters also uses the volume of PG&E electric meters and gas modules replaced in 2012 due to corrective maintenance.

Discussion

We adopt TURN's proposed reduction of $2.6 million to PG&E's forecast. Our adopted forecast incorporates TURN's unit cost applied to PG&E's count of meters to be read. We do not accept DRA's forecast of maintenance meters. As PG&E notes, not all maintenance issues require meter replacement. Some meters are repaired in the field. PG&E's forecast of 71,180 meters to be manually read in 2014 during maintenance accounts both for meters to be replaced and meters to be repaired. We accept PG&E's estimated maintenance meter count as reasonable.

PG&E also forecasts technically challenged meters requiring manual reads during 2014 of 15,600, whereas DRA forecasts 5,978. DRA's forecast is based on a

PG&E data response which "identified the *current* number of 'technically challenged meter premises [to be] at least 5,978.'" DRA used this February 2013 number as a proxy for its 2014 forecast. PG&E's mass deployment of SmartMeters™ is not yet concluded, however. As deployment continues, the volume of technically challenged meters will fluctuate. Because many of the remaining meters left to be deployed are in geographically challenging locations, many may not connect to the mesh network. Given these factors, we accept PG&E's forecast for technically challenged meters for 2014, based on its deployment experience, as reasonable.

5.5.3. SmartMeter™ Maintenance Expense

PG&E forecasts $7.6 million in expense to handle SmartMeter™ maintenance work including network communication issues and proactive maintenance response to meter alarms and flags generated by the SmartMeter™ technology.

DRA opposes PG&E's entire $7.6 million forecast for SmartMeter™ maintenance expenses. TURN recommends a $4.8 million reduction to PG&E's expense forecast. DRA argues that the increase in SmartMeter™ maintenance issues in 2014 will be offset by PG&E employees becoming more familiar with this new type of work, thereby increasing efficiency.

TURN argues that PG&E promised a specific level of 2014 maintenance expenses during the AMI and SmartMeter™ Upgrade (SMU) proceedings in 2006 and 2008.[56] PG&E claims, however, that it committed to delivering the systems, operational process changes and functionality required to enable the

[56] Exh. 118 (TURN/Nahagian) at 26, Lines 1-7.

benefits outlined in the AMI and SMU applications, and that it delivers on that commitment. PG&E claims that its GRC forecasts include the full annualized SmartMeter™ Program savings in the amount of $116.3 million in expense savings and an additional $5.8 million in capital expenditure benefit.[57]

Discussion

We adopt PG&E's forecast of $7.6 million in expense to handle SmartMeter™ maintenance work including network communication issues and proactive maintenance response to meter alarms and flags generated by SmartMeter™ technology. PG&E's method for estimating 2014 meter maintenance expenses is reasonable by utilizing recorded 2011 expenses as a base with evaluation of changes up to and including the 2014 test year. PG&E has reasonably estimated 2014 meter maintenance expenses reflecting the current work load experienced by FMO and evaluating current and forecasted conditions for their effect on costs.

5.5.4. Routine Electric Meter Testing

PG&E forecasts $4.9 million in expense to resume its electric routine meter testing program (R-Test). In PG&E's AMI proceeding, the Commission approved a temporary curtailment for PG&E's routine testing of electric meters during the mass SmartMeter™ deployment period (2007-2011). As deployment comes to an end, PG&E plans to reinstate this field testing program - needed to ensure meter accuracy - at full scale.

DRA opposes PG&E's incremental request of $4.9 million, arguing that there is no customer benefit to test meters when more than 99% are testing

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[57] Exh. 22 (PG&E-5) at 10-6, Lines 1-8.

accurately. DRA asserts that customers have the option to have their meters tested if they believe the meters are inaccurate. DRA contends that increased information transmitted by Smart Meters™ gives PG&E greater ability to identify and remediate inaccurate meters.

PG&E argues that the R-Test program is a proactive way to ensure its meters continue to perform at 99% or greater accuracy, thereby allowing PG&E to meet the Commission-approved tariff standard for billing accuracy, which depends in turn upon meter accuracy. PG&E claims that denial of funding would deny access to an important tool needed to help PG&E ensure billing accuracy.

Discussion

We adopt PG&E's forecast of $4.9 million for R-testing meters. In opposing PG&E's forecast, DRA does not address the underlying need for such testing as preventative maintenance. We accept PG&E's explanation regarding the value of proactive testing as an effective tool to ensure that meters continue to perform at 99% accuracy or greater, thereby allowing PG&E to comply with Commission Rule 17 for billing accuracy which depends on meter accuracy. Ad hoc testing of meters does not replace a proactive approach. The R-tests can also identify problems with other related meter equipment such as transformers or wires and enable PG&E to resolve the issues with the customer.

5.5.5. Field Meter Operations (FMO)

PG&E forecasts expenses of $1.5 million for eight new positions to be added to FMO between 2011 and 2014. The 2011 reorganization of Gas and Electric Operations resulted in the assignment of additional work to FMO that included gas module changes and maintenance. This additional work requires additional personnel.

DRA recommends no incremental funding for these additional FMO positions. DRA contends that PG&E has embedded funding for providing oversight to employees performing gas module changes and maintenance. PG&E denies that embedded funding exists.

Discussion

We adopt PG&E's forecast of an incremental $1.5 million for MWC EY for the ongoing FMO costs to add eight new positions between 2011 and 2014. As PG&E explains, these positions are new and are not merely a shifting of existing positions embedded in 2011 recorded expenses. The FMO now has a workforce that did not exist in 2011, and that was created to address challenges to adapt to evolving meter technology. FMO created a new position: the Meter Maintenance Person (MMP). The MMP workforce did not exist in 2011. As of December 2012, PG&E employed 57 MMPs and forecasts that this number will grow to 67 in 2014. These new positions authorized here are to manage the MMPs and their growing workload, and to ensure compliance, quality assurance and control, records retention, resource planning and training.

5.5.6. MAME

PG&E forecast expenses of $2.1 million ($1.4 million in MWC EY and $0.7 million in MWC HY) for 18 positions added to the MAME organization. The newly established MAME organization is responsible for management of five million electric meters and four million gas meters and modules, and is accountable for ensuring safe, accurate and reliable meters.

DRA recommends no incremental funding for the MAME positions. DRA asserts that more overtime work was charged to MWCs HY and EY in 2011 than the historic 2007-2010 average, and that a reduction in overtime in 2014 will offset the costs of the new MAME employees. PG&E responds that more

overtime costs were charged to MWCs EY and HY in 2011 than the historic 2007-2010 average because of work demands. PG&E employees could have worked less overtime in 2011 if there were more employees to perform the work. PG&E argues that it is reasonable to hire new employees to handle the increased workload that caused the 2011 overtime, rather than to accept DRA's assumption that workload and the associated overtime will simply disappear.

Discussion

We adopt PG&E's forecast for MAME as reasonable. The MAME employee work is driven by the demand of new meter technology. Since this is new work, it is not funded by existing rates. The work includes evaluating and approving new meter products, and implementing firmware and software upgrades and product design changes as a result of improved meter technologies. MAME employees will troubleshoot and provide solutions to metering issues, develop standards and work procedures for field personnel, and engage in other activities that have been accomplished under the umbrella of the SmartMeter™ Project during the 2007-2013 period. During that prior period, these activities were integrated with deployment. The related costs were charged to the SmartMeter™ Balancing Accounts (SBAs) and were not included in GRC funding or in 2011 recorded MWC EY or HY costs. In conclusion, PG&E's requested funding is adopted.

5.5.7. Gas and Electric Meter Services (GEMS)

PG&E forecasts expenses of $3.7 million ($3.0 million in MWC EY and $0.7 million in MWC HY) for 17 new positions in its GEMS group to support the increase in work related to shop-testing meters. With the SmartMeter™ deployment nearing completion, this critical element of the meter maintenance

process has transitioned to operations and will no longer be handled under the SmartMeter™ Project.

DRA proposes a reduction of $2.7 million to PG&E's GEMS forecast, based on escalating PG&E's 2012 recorded GEMS expenses.

Discussion

We adopt PG&E's forecast for GEMS costs as reasonable. We are not persuaded that 2012 recorded costs are a valid basis for a 2014 forecast. The new meter shop-test processes and work are in response to the new generation of Smart Meters™ deployed during that period, and are required to maintain meter and bill accuracy. Thus, most of the new GEMS work did not result in costs for 2012. PG&E's GEMS forecast supports additional positions not funded prior to 2012, as well as launching a new gas module warranty process.

5.5.8. Installation of New Electric and Gas Meters

PG&E forecasts capital expenditures of $38.649 million in 2012, $44.392 million in 2013, and $42.598 million in 2014 in MWC 25 for electric meter replacement and customer growth; installation labor; corrective maintenance requiring meter exchange or replacement; meter removals and retirements; Load Research Program costs and SmartMeter™ network equipment. The forecast includes the cost of purchasing and installing electric interval type meters and telemetry support for new and existing customers with load over 200kW. The forecast also includes replacement of electric interval meters installed as part of a California Energy Commission (CEC) program to provide large customers with on-line interval data. PG&E's forecasted unit volumes are largely based on base year 2011 data with the exception of new work (i.e., SmartMeter™ maintenance growth, solar customer meters, etc.).

DRA forecasts capital expenditures of $48.357 million in 2012, $35.706 million in 2013, and $38.0 million for 2014, for a reduction of $4.608 million to PG&E's forecast. DRA uses PG&E's 2011 unit cost forecast and escalation factors to derive 2013 and 2014 unit cost estimates. DRA multiplies derived yearly unit cost forecasts by a three-year average (2010-2012) of recorded unit volumes; and (3) for expenditures without units, taking a three-year average (2010-2012) of recorded expenditures and escalating to derive 2013 and 2014 forecasts.

PG&E forecasts capital expenditures of $48.357 million in 2012, $35.706 million in 2013, and $84.391 million in 2014 in MWC 74 for capital expenditures for replacement and new customer growth, associated new gas meter installations, meter removals and retirement costs, Load Research Program costs and SmartMeter™ network equipment including gas modules. DRA forecasts $761.842 million for 2012, $68.857 million for 2013, and $70.9 million for 2014, or a net three-year decrease of $40.2 million from PG&E's forecast. DRA uses PG&E's 2011 unit cost forecast and escalation factors to derive 2014 unit cost estimates, and multiplying the unit cost forecasts by a three-year average (2010-2012) of recorded unit volumes. For expenditures without units, DRA uses a three-year average (2010-2012) of recorded expenditures and escalates to derive 2013 and 2014 forecasts.

Discussion

We adopt PG&E's 2014 capital forecast of $42.598 million for electric meter installations and $84.391 million for gas meter installations. We decline to adopt DRA's recommended reductions of $18.1 million for new gas and electric meter installations. DRA accepts PG&E's forecasted unit costs, but estimates a different volume of units. PG&E's 2014 forecasted unit volumes are based largely on 2011

unit volumes with the addition of new work. DRA's forecasted unit volumes are based on a three-year average (2010-2012). DRA's historic average does not reflect changed conditions expected to occur in 2014.

DRA makes no adjustment for impacts of new work on the level of 2014 capital expenditures. DRA's three-year average estimating also does not reflect the 2010 balancing account costs. The 2011 and 2012 recorded units do not accurately represent the number of meter and module replacements needed in 2014. The SmartMeter™ Project was still deploying electric meters and gas modules in 2011 and 2012, and since that time the population of deployed meters that may require maintenance has increased.

PG&E's forecast reasonably reflects new activities planned for 2014 including expenditures to perform and/or purchase meters for PG&E's Scheduled Meter Change (SMC) Program, SmartMeter™ gas module replacement, temperature compensating indexes, SMC-related regulator replacements and turbine and rotary meter replacements. PG&E's 2014 forecast unit volumes are largely based on base year 2011 unit volumes with the exception of new work (i.e., SmartMeter™ maintenance growth, solar customer meters, etc.).

5.5.9. Escalation

PG&E forecasts $2.743 million for escalation of metering expenses. DRA proposes adjustments to PG&E's escalation forecast, resulting in a reduction of $0.84 million to MWCs DD (Field Services), EY (Change/Maintain Used Electric Meters), and HY (Change/Maintain Used Gas Meters).

DRA proposed an escalation reduction of $0.29 million for providing field services in MWC DD. DRA states that the reduction should be made due to DRA's "allocation of escalation." DRA references the 2011 reorganization of Gas

and Electric Operations and notes that the reorganization led to a split of MWC DD into three organizations (Electric Operations, Gas Operations, and Customer Care).

Discussion

We adopt PG&E's escalation forecast as reasonable. We find no basis to adopt DRA's proposed escalation reductions. DRA does not explain how the division of responsibility supports its proposed escalation reduction in MWC DD. DRA also appears to rely on the same rationale its proposed escalation reduction to MWCs EY and HY. PG&E forecast has been reduced to account for the transfer of specific work to Gas Operations.

5.6. QAP/Safety Net Program

Consistent with prior GRCs, PG&E presented data concerning its performance under the QAP and the Safety Net Program. PG&E did not request any changes to these programs, nor request any expenses associated with these programs. No party has raised any issue or concern in this area.

5.7. Customer Energy Solutions (CES)

PG&E's CES provides service to large commercial, industrial and agricultural customers and to SMB customers, as well as residential customers. PG&E forecasts $80.4 million to increase its level of basic customer service and respond to customer needs as more complex policies and rate programs are implemented.

DRA recommends a reduction of $44.9 million to PG&E's CES expense forecast for: MWC IV (Provide Account Services), MWC FK (Retain and Grown Customers), and MWC EZ (Manage Various Customer Care Processes). MID agrees with DRA's recommended reduction to MWC FK (Retain and Grow Customers).

5.7.1. Provide Account Services (MWC IV)

PG&E's incremental 2014 expense forecast for MWC IV (Provide Account Services) is $24.1 million. Planned activities include: (a) providing customers with basic customer service through Energy Solutions & Services customer account managers, and (b) providing customer support to Community Choice Aggregation (CCA). DRA recommends a $22.6 million reduction to PG&E's expense forecast in this area. The Greenlining Institute and Small Business Utility Advocates support PG&E's proposed increasing of services to SMB customers.

DRA opposes PG&E's incremental expense forecast for customer account managers asserting that they have historically been funded through non-GRC sources allocated for marketing, education and outreach. DRA argues that PG&E has embedded funding from D.11-05-018 (2011 GRC), D.12-04-045 (Energy Efficiency), D.12-11-015 (Demand Response), and also that PG&E has requested funding through A.10-02-028 (2010 Rate Design Window (RDW)).

PG&E claims DRA's arguments are contrary to Commission precedent, and ignore the distinction between the types of work conducted by customer account managers.

Discussion

We approve a more limited funding increase than PG&E proposes. PG&E request of $24.1 million is more than the $10.5 million spent in 2011. We are concerned about the scope of the increase given the fact that PG&E dramatically underspent what it was authorized in the last GRC. (DRA Brief, at 264). We are concerned that PG&E could again shift funds somewhere else. Also, PG&E has been providing support for these basic services all along. Even assuming that

SMB customers have been underserved, such a 230 % increase (including 146 FTEs) over 2011 tracked costs is warranted.

We shall authorize an increase based on staffing level increases from 64 positions in 2011 to 148 positions in 2014 (an increment of 84 positions). The figure of 84 is based on the same per-year rate of change (i.e., 28 positions per year) that PG&E allowed staffing decline from 176 positions (in 2007) to 64 positions (in 2011). This alternative approach would not give PG&E their full funding request of 176 positions, but more than DRA proposes bear some relationship to PG&E's actual pattern of spending changes over time. We may consider further staffing allowances in the next GRC cycle based on a further showing of need. The funding authorized in the other proceedings referenced by DRA cover different activities that are separate and distinct from what PG&E is requesting here for customer account managers to engage in basic customer service activities such as advising customers on rates, interpreting tariff information and resolving billing issues. These sorts of activities have historically been funded through the GRC, not via non-GRC sources.

The funding approving PG&E's energy efficiency and demand response programs, as referenced by DRA, can only be used for specific energy efficiency and demand response activities that are the subject of other proceedings. Within the energy efficiency context, the Commission sets the parameters of activities to be funded through the energy efficiency balancing account. PG&E does not have discretion to use those funds for the basic customer service activities forecasted in this GRC.

PG&E's forecasted increase in basic customer service will enable customer account managers to provide a higher level of service to SMB customers who have traditionally received less service as compared to Large Commercial and

Industrial customers, and who will be transitioning to default PDP in November 2014. PG&E's forecast would provide basic customer service to approximately 30% of SMB customers.

5.7.2. CCA Support

DRA recommends a reduction in the area of CCA customer support by basing its CCA customer forecast on only those cities and counties that are currently exploring CCA. PG&E claims that DRA's analysis is too narrow.

Discussion

We adopt PG&E's forecast. PG&E developed one scenario by taking into account the number of customer Service Agreements for each entity that is exploring CCA as an option and has publicly expressed an interest in launching a CCA program during the past two years. PG&E then developed a second, lower scenario by applying a 30% Opt-Out rate to its initial scenario. PG&E's forecast is a mid-range between these two scenarios. We conclude that PG&E's forecast is reasonable since it is based on a more comprehensive analysis of the potential CCA population.

5.7.3. Retain and Grow Customers (MWC FK)

PG&E forecasts 2014 CES incremental expense for the areas of Retain and Grow Customers of $2.8 million in MWC FK. PG&E forecasts costs to participate in business attraction and retention activities; collaborate with local, regional and state economic development organizations on economic growth programs; and pay membership dues for state economic development organizations.

DRA recommends a $2.6 million reduction to PG&E's forecast. The MIDs support DRA's recommended reduction. DRA argues that PG&E's Retain and Grow Customers activities have already been funded through local government partnerships and statewide institutional partnerships funded in previous energy

efficiency proceedings. DRA recommends that PG&E's 2014 funding be based on a five-year historic average (2007-2012).

PG&E argues, however, that energy efficiency proceeding funds cannot be used for nonenergy efficiency activities. PG&E's Local Government Partnerships are a component of PG&E's energy efficiency program and are distinct from the Retain and Grow Customers forecast in this GRC. DRA also asserts that the amount of historical funding in this area is not directly proportional to the number of customers retained.

Discussion

We adopt PG&E's forecast as reasonable. PG&E's funding levels over the last five years have been low as compared to the pre-2007 period, and the lower funding level has correlated to lower project results. Maintaining the same level of expenditures, based on a five-year average, would not be sufficient to support the increased scope of planned activities. Historical funding and staffing levels are correlated with business attraction and retention success. From 1996 through 2007, PG&E recorded 185 successful Retain and Grow Customers projects, or an average of approximately 15 per year. From 2008-2012, during a period of reduced staffing levels, PG&E recorded only 16 successful projects, or approximately three per year.

PG&E's expenses and staffing declined significantly from $1.2 million in 2007 to $0.7 million in 2008. Although recorded expenses increased slightly to $0.9 million in 2012, the proportion of funding dedicated to organization dues increased as compared to the historic period from 1996 through 2007. As a result, the amount of funds available for actual project activities in 2012 was not sufficient to mimic the successful business retention results experienced in the pre-2007 period.

5.7.4. Manage Customer Care Processes (MWC EZ)

PG&E's incremental 2014 expense forecast is $31.6 million for MWC EZ (Manage Customer Care Processes) for: (1) Safety and Reliability Outreach ($5.4 million) to increase customer awareness of how to handle hazardous situations; and (2) Customer Rate Education and Outreach Program ($18.0 million). The forecast includes $9 million in Customer Research, Planning and Product Development costs for (1) an additional employee in the Customer Insight and Strategy (CI&S) Department to continue customer research, strategic planning and database management; and (2) ten employees in the Pricing Products Department to support and promote customer needs in synch with emerging interests.

PG&E's forecast is $19.7 million higher than 2011 recorded expenses. Customer Education and Outreach includes: DRA recommends a 2014 forecast of $19.8 million less than PG&E, claiming that PG&E received funding from non-GRC sources for Customer Rate Education for 2014, and has embedded 2011 GRC funding. DRA recommends using 2011 recorded expenses for 2014 ($11.0 million decrease); (3) CI&S Department activities were requested in the 2011 GRC while from 2007-2011 PG&E decreased spending by more than 50% ($1.1 million decrease); and (4) Pricing Products and Policy and Integrated Planning departments have increasingly been funded from non-GRC sources ($2.9 million decrease). DRA recommends allowing escalation from 2011 levels for CI&S, Pricing Products and Policy and Integrated Planning departments (would be a partial offset to the decreases described above).

5.7.4.1. Electric and Gas Safety and Reliability Outreach

PG&E forecasts $5.4 million for 2014expenses for Electric & Gas Safety and Reliability Outreach in MWC EZ to expand community-oriented and local outreach to focus on general gas and electric safety awareness and education.

DRA proposes zero funding for this activity, arguing that available funding for Safety and Reliability Outreach is already embedded in other line of business account activity. PG&E disagrees, arguing that these activities are distinct from the project-specific activities funded within the other LOB.

Discussion

We adopt PG&E's forecast. The safety and reliability activities forecast in CES are focused on seasonal messages and broad customer outreach activities. We conclude that there is no embedded funding to cover the forecasted expenditures which are distinct from the project-specific activities within other LOB.

Liberty's Report to the Safety and Enforcement Division anticipates that PG&E's forecast electric and gas safety and reliability outreach activities, including local events, locally targeted media, printed collateral and online communications will contribute to reduced third-party electrical contact incidents.[58] Greenlining has also recognized the importance of educating PG&E's diverse base of customers regarding electric safety.

By adopting PG&E's proposed funding, we recognize the importance of increased electric and gas safety communications.

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[58] *See* Liberty Report at 158-159.

5.7.4.2. Customer Rate Education and Outreach

PG&E forecasts $18 million for 2014 Customer Rate Education and Outreach in MWC EZ. DRA recommends an $11.0 million reduction to PG&E's Customer Rate Education and Outreach forecast, resulting in a $7.0 million forecast for Customer Rate Education and Outreach which is equal to PG&E's 2011 recorded PDP expenses charged to MWC EZ.

DRA recommends funding PG&E's overall 2014 Customer Rate Education and Outreach activities at the level of 2011 recorded expenses for non-residential PDP outreach implementation.

PG&E claims that use of 2011 recorded costs for PDP implementation as a proxy for the 2014 Customer Rate Education and Outreach forecast is arbitrary and unreasonable given the difference in scope. PG&E also denies requesting or receiving funding for specific general rate education and outreach activities in other proceedings.

Discussion

We adopt PG&E's forecast of $18 million for Customer Rate Education and Outreach. As customers continue to move toward more complex time-varying pricing programs, PG&E needs to proactively provide customers with clear and comprehensive rate education. The approved funding offers PG&E the tools for such effective education and outreach. We conclude that PG&E's Customer Rate Education and Outreach forecast also does not overlap with funding requested in the 2011 GRC or the 2010 RDW proceeding. DRA Witness Morse also agreed that the scope of work encompassed by PG&E's 2014 expense forecast for Customer Rate Education and Outreach is different than the more limited scope of work comprising 2011 recorded costs for PDP implementation.

5.7.5. Customer Insight and Strategy (CI&S)

PG&E's 2014 forecast for its CI&S department expense in MWC EZ is $1.1 million. The requested increase is to allow continued foundational customer research, obtain customer feedback, ensure proper classification of customers in its database, and purchase external classification data to refresh customer information and improve North American Industry Classification System (NAICS) coding of business customers.

DRA recommends no incremental funding for CI&S since PG&E sought NAICS-related funding in the prior GRC. PG&E argues that customers benefit from this program, and that information produced through this research will become more necessary as additional business customers default to time-varying pricing programs in the 2014 GRC cycle. PG&E also experienced increased demand to conduct customer research.

Discussion

We decline to approve PG&E's funding request for this program. PG&E requested funding in its 2011 GRC to purchase external classification data to refresh customer information and improve NAICS coding of business customers. PG&E did not receive its full forecasted revenue requirement in the 2011 GRC. Based on the reduced level of funding that was received, however, PG&E did not consider this program of sufficient priority to fund it.

We recognize that this program offers some potential for benefits by providing customers with targeted data on energy tools and pricing options to help them manage their energy bills. Given the competing programs for ratepayer funds in this GRC, we conclude that the claimed benefits from this program are not sufficient to prioritize it for additional ratepayer funding for this GRC.

5.7.6. Pricing Products/ Policy and Integrated Planning (PIP)

PG&E's 2014 expense forecast for its Pricing Products department is $1.7 million. The requested funding is to enable the department to develop, improve and maintain self-service tools and resources so customers can view their energy usage and filter through their rate options.

PG&E also forecasts $1.2 million of expense in MWC EZ to support its PIP department activities which provide regulatory and policy support on issues impacting PG&E and its customers such as utility infrastructure safety and reliability, legislative and regulatory requirements related to California's clean energy goals, and management of customer information and rate proceedings. PG&E explains that the work forecast for Pricing Products and PIP in this GRC cannot be charged to non-GRC funding sources, such as energy efficiency and Demand Response.

DRA recommends no incremental funding for Pricing Products or for PIP. DRA believes that PG&E has Energy Efficiency and demand response funding that can fund forecast expenses for these programs.

Discussion

We adopt PG&E's forecast for its Pricing Products and PIP departments. With the trend toward time-varying rates and other rate design changes, PG&E's Pricing Products department helps customers understand their rate options, tools and thereby give customers greater control over their energy bills. We conclude that although a portion of the rate programs supported by Pricing Products may be funded by non-GRC proceedings, the strategic function and the development of integrated communications on rate design changes, as forecasted in this GRC, are separate activities that warrant GRC funding. The PIP activities

forecast in this GRC focus on strategic management of multiple rate programs, options and tools that are available to customers.

5.8. Customer Retention Expenses (MWC FK)

PG&E forecasts $1.5 million of 2014 expenses in MWC FK for customer retention activities to enable PG&E to provide a full and accurate analysis of the financial impact to remaining customers if a publicly-owned utility (POU) takes over or expands service in PG&E's service area.

PG&E claims that Customer Retention expenses are increased to ensure that customers, the Commission, local officials, and other interested stakeholders receive accurate data and information on the financial impact to customers of POU who are seeking to provide or expand service within PG&E's service area.

DRA recommends no funding for Customer Retention activity. Merced and Modesto Irrigation Districts (together, MID) and MEA also recommend no funding for customer retention activities.

DRA argues that ratepayers should not fund utilities' efforts to "block or oppose" reasonable municipal utility projects. MEA assumes that PG&E's customer retention forecast includes costs to discourage customers from choosing unbundled service through CCA. PG&E claims that its Customer Retention expenses do not "block or oppose" municipal utility projects, and that CCA-related costs are excluded from the forecast and would be recorded below-the-line.

MID argues that PG&E does not need customer retention funding because it has ample tools to address its concern about POU alternatives including the ability to plan for customer departures, collecting non-bypassable or departing load charges, and offering competitive rate options.

CCSF also opposes PG&E's proposed funding for Customer Retention activities. CCSF argues that PG&E's customer retention activities are essentially efforts to stymie the lawful right of local governments to provide power to their constituents. CCSF claims that PG&E's proposal here would use ratepayer funds to undermine longstanding state policy providing support for publicly-owned utilities. CCSF claims that is not just and reasonable to have ratepayers fund activities intended to limit their ability to receive power from a publicly-owned utility. CCSF filed a motion on September 19, 2013, for official notice of multiple documents relating to PG&E's customer retention activities.[59]

PG&E claims that it cannot avoid the impacts of municipalization to its customers by advance planning and collection of non-bypassable charges. PG&E claims that a POU's expression of intent of potential future municipalization does not equate to the ability to implement the planned municipalization. PG&E explains that it has an obligation to serve its customers and does not stop procuring power on behalf of existing customers solely because an entity has expressed future municipalization plans.

Discussion

We decline to approve any ratepayer funding for Customer Retention activities. We are not persuaded that PG&E has justified imposing an additional

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[59] We grant the motion of CCSF, dated September 19, 2013, for official notice of the documents set forth in its motion (listed therein as Exhibits A through M). As noted in the CCSF motion, Exhibits A through C are excerpts from San Francisco general election voter pamphlets containing public power measures put to the electorate in 2001, 2002 and 2008. Exhibits D through F are campaign disclosure forms filed by PG&E with the San Francisco Ethics Commission as required by state law. Exhibits G through M are documents regarding relating to PG&E's spending on initiatives relating to public power.

$1.5 million in costs on ratepayers to fund customer retention activities. PG&E does not track its customer retention costs by activity, location, requesting entity or otherwise.[60] Consequently, PG&E cannot show exactly how the funds have historically been spent. Given the lack of data regarding how PG&E has historically spent customer retention funds, we conclude that PG&E has not satisfied its burden of demonstrating that rates based on these requested revenues are just and reasonable. As such, we find no basis for approving funding for customer retention activities. Accordingly, we are not persuaded by the Ratepayer Impact Measure (RIM) analysis prepared by PG&E which presents a variety of scenarios and assumptions by which to gauge claimed benefits to ratepayers from PG&E's customer retention activities. We recognize that PG&E has an obligation to serve its customers and does not stop procuring power on behalf of existing customers solely because an entity expresses plans for future municipalization. While we are not certain that PG&E's Customer Retention forecast necessarily includes activities designed to block or oppose municipal utility projects, at the same time, we are not persuaded that it is in ratepayers' best interests to bear this cost.

5.9. Customer Care IT Program

PG&E forecasts $8.2 million expense for the Customer Care IT Program to adapt to the evolving technology landscape, improve customer service, and capture efficiencies across Customer Care. These expenses reside in MWC JV.

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[60] *See* RT pp. 3454:2-28 and 3488:17-3489:26 wherein PG&E witness Reuben stated: "We don't track the costs according to the specific type of activity, nor do we specifically track it according to whether the information is provided to a governmental agency or a customer." (Rubin/PG&E).

DRA and TURN respectively recommend $4.7 million and $2.4 million in expense reductions to a combined five areas of dispute.

PG&E includes six IT projects, including the Customer Interaction and Relationship Management (CIRM) project, in which PG&E plans enhanced IT capabilities to ensure consistent yet personalized and proactive interactions driven by customer preferences. PG&E will provide customers with enhanced self-service and energy management functions through their preferred channels. PG&E describes the CIRM project as core to enabling a consistent self-service experience across channels. The remaining IT projects: Customer Self-Service and Energy Management Enhancements, Interval Data Processing and Exceptions Management, Optimizing Time to Market for Rates, Meter Management, and Miscellaneous Other Technology projects.

DRA recommends a reduction of $4.7 million to PG&E's forecast. DRA removes the $3.0 million for CIRM project arguing that the project is in a very early planning stage and doesn't include a mechanism to ensure that benefits will be achieved. DRA accepts the Customer Self-Service and Energy Management Enhancements project but recommends a 14% reduction for this and other IT projects (described below) calculated using the Concept Estimating Tool for a 2014 expense forecast of $0.67 million. DRA accepts the Interval Data Processing and Exceptions Management project but recommends that expense levels be normalized from 2014-2016 for a 2014 forecast of $1.36 million. DRA accepts the Meter Management project but recommends that expense levels be normalized from 2014-2016 for a 2014 forecast of $0.45 million.

PG&E's capital expenditures forecast for Customer Care IT projects is $33.4 million. DRA and TURN respectively recommend $22.8 million and $28.3 million of capital expenditure reductions in the same areas of dispute and

based on the same arguments made to support their recommended expense reductions.

DRA's overall IT reduction incorporates its recommendation for a global 14% reduction across all of PG&E's IT forecasts developed using PG&E's Concept Estimating Tool.

5.9.1. Customer Interaction and Relationship (CIRM)

PG&E forecasts $3.0 million in expense and $12.0 million in capital for development of the CIRM project comprised of: (1) Customer Insights and Preference Management, (2) Channel and Interaction Management, and (3) Case and Feedback Management. These initiatives enable a complete customer service loop from collecting customer preferences, to delivering tailored service based on the preference information, and then compiling customer feedback.

DRA and TURN oppose capital and expense funding for the CIRM project. DRA recommends no funding on the basis that the CIRM forecast lacks substantial analysis. TURN recommends that the project be re-scoped so that costs are more in line with financial benefits. PG&E claims, however, that it did provide substantial detailed analysis to support its CIRM forecast, consistent with the analysis provided for other IT projects including the Customer Self-Service and Meter Management projects accepted by DRA.

Discussion

We adopt PG&E's capital and expense CIRM forecasts. As PG&E explains, the CIRM project will enable collection and centralization of customer interactions and preference information to enable a consistent self-service experience across channels (e.g., mobile, web, phone). We conclude that PG&E provided adequate analysis to support its CIRM forecast, consistent with the

level of analysis provided for the other IT projects including the Customer Self-Service and Meter Management projects accepted by DRA. PG&E's Customer Self-Service project will create and enhance self-service systems to provide customers with self-service and energy management functions through their preferred channels. To do this effectively, PG&E will need to enable two of the CIRM initiatives: Customer Insights and Preference Management, and Channel and Interaction Management. These initiatives will create a centralized customer interaction hub where customer preference and channel information will be stored. The third CIRM initiative, the Case and Feedback Management, also improves customer service by enabling a CSR to initiate a case and dispatch it across several work groups; with automated workflow, case aging, and reporting capabilities.

5.9.2. Interval Data Processing and Exceptions Management (IDPEM)

PG&E forecasts 2014 budgets of $1.8 million in expense and $16.0 million in capital to develop the IDPEM project. This project will re-platform PG&E's MTC IT architecture to improve the automated support of prebilling exceptions (i.e., identifying potential issues with usage data prior to issuing a customer bill) by improving validation and edits of interval energy usage data collected by SmartMeter™ devices. The re-platform will also improve PG&E's ability to identify the root cause of pre-bill exceptions, and facilitate more efficient pre-bill exception resolution.

TURN opposes PG&E's entire expense forecast and $15.5 million of PG&E's capital forecast for the IDPEM project based on similar arguments used to oppose PG&E's forecast for increased staff to manually process the increased volume of interval data exceptions generated by the new SmartMeter™

technology. TURN argues that the IDPEM project is not warranted because current interval data is good enough, and it would be premature to ensure the accuracy of interval data for residential customers who are not yet billed on interval rates.

PG&E responds that all customers have access to their interval energy usage data on PG&E's website. The IDPEM project will improve data accuracy by reducing the level of interval data exceptions and enabling PG&E to process the remaining exceptions more efficiently. PG&E claims that customers need access to accurate interval usage data to guide energy usage behaviors

DRA recommends two adjustments to PG&E's expense forecast: (1) application of its global 14% reduction; and (2) normalization of yearly forecast expenses over the 2014-2016 GRC cycle. PG&E argues that DRA's recommendation to normalize the project assumes that PG&E's total forecasted expenses for the project can be divided evenly over a three-year period without negatively impacting the project.

Discussion

We decline to adopt PG&E's forecast. We agree with TURN that the funding the IDPEM project is not warranted at this time since current interval data is good enough. It would be premature to ensure the accuracy of interval data for residential customers who are not yet billed on interval rates. We duly adopt no expense funding and $0.5 million in capital funding for the IPDEM project.

5.9.3. Meter Management Project

PG&E forecasts $1.6 million in expense and $0.9 million in capital for the Meter Management Project. PG&E plans to use this project to replace disparate legacy meter systems with SAP enterprise Solutions and to comprehensively

manage and maintain meters including offering the capability to track activities related to the repair of gas and electric meters; to improve meter refurbishment integration with supply chain systems; to improve meter quality management, the maintenance process and the manufacturer return process.

DRA and TURN accept PG&E's expense forecasts for its Meter Management project except for two adjustments: (1) application of its global 14% reduction; and (2) normalization of yearly forecast expenses over the 2014-2016 GRC cycle.

PG&E explains that its forecast for Meter Management requires completion of the project in 2014, following the implementation of the Meter Traceability project, which is currently in progress. Meter Management is not the type of project that allows for equal distribution of resources over multiple years of development, since change management activities are expected to be significant. DRA's recommendation to normalize the expenditures would delay implementation of the project, necessitate additional change management and result in cost overruns.

Discussion

We reduce PG&E's capital and expense forecasts to reflect DRA's global 14% adjustment based on use of PG&E's Concept Estimating Tool. In all other respects, we adopt PG&E's forecast. We do not adopt DRA's recommendation to normalize the expenditures. We agree with PG&E that normalization of the forecast amount is not appropriate. Meter Management is not the type of project that allows for equal distribution of resources over multiple years of development.

5.9.4. Customer Self Service and Energy Management Enhancements Project (Customer Self-Service)

PG&E forecasts $0.8 million in expense and $4.0 million in capital for the Customer Self-Service Project to improve and expand customers' self-service options across energy management tools and enable customers to complete self-service transactions through their preferred channel. Self-service transactions will include but not be limited to payments, appointment scheduling, start/stop service, and other customer interactions. DRA recommends the global 14% reduction to the Customer Self Service project which amounts to a $0.1 million reduction.

Discussion

We reduce PG&E's capital and expense forecasts to reflect DRA's 14% global reduction. In all other respects, we adopt PG&E's forecast.

5.9.5. Miscellaneous Other Technology Projects

PG&E forecasts $1.0 million in expense and $0.5 million in capital to enable IT to support currently unforeseen Customer Care operational business needs that may arise during the 2014 GRC cycle. No party opposes PG&E's forecast for miscellaneous IT projects. TURN applies DRA's global 14% reduction to this expense forecast for a $0.14 million recommended reduction.

Given DRA's proposal that the global reduction should apply to IT projects forecast using PG&E's Concept Estimating Tool, PG&E argues that it was not appropriate for TURN to apply the reduction to this Miscellaneous expense forecast, which is not based on the Concept Estimating Tool. DRA did not apply the reduction to this expense forecast.

Discussion

We adopt PG&E's capital and expense forecasts of miscellaneous other technology projects with no reduction imposed.

5.10. SmartMeter™ Program

PG&E launched the SmartMeter™ Opt-Out Program (SMOOP) on February 1, 2012, and began changing out SmartMeters™ to meet the requests of those customers who elected not to have a SmartMeter™. PG&E has requested in this GRC that the Commission approve the ongoing costs for operating the SMOOP during the 2014 GRC period, net of revenues received from participating customers. PG&E expects to complete mass deployment under its SmartMeter™ Program by the end of 2013. PG&E's SmartMeter™ Program-related proposals in this GRC focus on activities needed to close out SmartMeter™ Program activities, including reflecting all of the ongoing savings that reduce the operational units' cost forecasts in this GRC. PG&E also requests consolidation with the 2014 GRC revenue requirement of the ongoing post-2013 capital-related revenue.

Given that the SmartMeter™ Program is transitioning to normal operations and PG&E plans to complete mass deployment in 2013, PG&E requests approval to:

1. Consolidate ongoing cost recovery of the capital-related revenue requirement associated with the SmartMeter™ Program up to the authorized cost cap with the 2014 GRC revenue requirement.
2. Close the electric and gas SBAs, including the elimination of the SmartMeter™ Benefits Realization Mechanism, and the electric and gas MRCBAs.
3. End deployment-related SmartMeter™ Program reporting requirements.

Discussion

No party opposes PG&E's proposed consolidation of capital-related revenue requirements associated with the SmartMeter™ Program up to the authorized cost cap with the 2014 GRC revenue requirement. We approve that proposal.

PG&E requests authorization to close the electric and gas SBAs. The SBAs have allowed cost recovery of the expenses and capital costs for the SmartMeter™ Program, and they allowed the savings realized through the deployment of SmartMeter™ technology to flow through to customers. We grant PG&E's request.

5.11. Accessibility Improvements

PG&E's opening testimony presented a joint proposal with the Center for Accessible Technology to effect accessibility improvements. This proposal was not been challenged by any party. We find the proposal reasonable and adopt it.

6. Energy Supply

6.1. Introduction

PG&E forecasts $722 million for Energy Supply expenses for 2014 (a 33% increase over 2011levels) and Energy Supply capital expenditures of $635.593 million (an increase of 18% over 2011 levels). PG&E's portfolio comprises owned and contracted energy supply resources, including nuclear, hydroelectric, fossil, and solar generation, as well as contracted energy resources to supply customer generation needs. PG&E's forecast starts with 2011 recorded costs, eliminates non-recurring or one-time projects, and assesses new regulatory and business demands for 2014. PG&E prioritized its generation investments, ranking safety-related projects highest, followed by regulatory-required work

and then environmental work. Reliability-related projects are then prioritized based on asset health, consequence of failure, and other criteria.

Investments are planned to replace aging and deteriorating facilities and equipment. PG&E takes into account changes in regulatory requirements and the condition of generating assets. The planning process takes into account the enhanced safety measures resulting from Enterprise Risk Management (ERM) and Energy Supply Operational Risk Management programs.

For its forecasts, DRA utilized PG&E's 2011 recorded adjusted expenses and PG&E's historical expense levels, including its 2012 recorded adjusted expenses. DRA reviewed and considered PG&E's historical Imputed Regulatory Values in its analysis and recommendations of each MWC.

6.2. Hydroelectric Generation

6.2.1. Hydro Expense Overview

PG&E hydroelectric facilities consist of 109 generating units at 68 powerhouses, and include water storage, conveyance systems and switching centers. PG&E forecasts $191.144 million for Hydro expenses for Test Year 2014, an increase of 43.69% over 2011 levels. Expense increases are driven by: (a) new programs for Hydro conveyances, penstocks, and dams to evaluate and mitigate safety risks; (b) new security requirements and records management; (c) dam repairs, support for ongoing land conservation efforts, and requirements in recently issued FERC licenses; and (d) price inflation.

PG&E's 2014 forecast includes ongoing and routine projects (Base work) [61] that have embedded historical costs, some of which were proposed in PG&E's 2011 GRC, but subsequently deferred or rescheduled. The Base Work forecast is $134.908 million. PG&E's Non-Base Work forecast, consisting of projects and programs that are unique and not repeated annually, is $56.236 million, an increase of 217.25% over 2011.

The disagreements for 2014 hydro expense forecasts between PG&E, DRA, and TURN are summarized by MWC as follows:

		$ in Millions		
		Forecast	**Proposed Reductions**	
Description	MWC	PG&E	DRA	TURN
Support	AB	$3.06	$-1.66	
Operate Hydro Generation	KG	$51.5	-8.4	
License Compliance	KJ	$47.9	-16.2	
Maintain Reservoir/Dams/Waterways	AX	$36.8	-15.1	
Maintain Structures/Roads	KI	$14.6	-3.47	
Maintain IT Applications	JV	$3.35	-2.46	
Other Miscellaneous MWCs				
Total		$191.1	$-47.3	$-31.50

The five-year average annual increase in PG&E's Base Work from 2007-2011 is 4.6%; compared to the PG&E forecast five-year average annual increase in Base Work from 2010-2014 of 4.7%. PG&E's forecasted rate of increase in base work is consistent with the historical trend of cost increases.

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[61] Ex. PG&E-6, workpapers at WP 2-11. Base Work is "the day-to-day, year-in-year-out routine work" and Non-Base work "includes projects and programs that are unique in nature, and are not repeated every year." (Ex. PG&E-6 at 2-6).

6.2.1.1. DRA's Position

DRA proposes an overall reduction of $47.3 million to PG&E's 2014 hydro expense forecast. DRA claims that PG&E's 2014 forecast is unreasonable in comparison to historical spending levels. Depending on the MWC in question, DRA forecasts 2014 expenses by averaging different historical periods, including one-year, three-year, or five-year averages. DRA notes that non-Base Work expenses fluctuated slightly between 2007 and 2011. Between 2007 and 2008, Non-Base Work expenses increased 23.95%. Between 2008 and 2009, they decreased by 2.59%. Between 2009 and 2010, they decreased by 19%. Between 2010 and 2011, they increased 37.78%.

PG&E claims that DRA's use of different historic periods to forecast various MWCs appears random. PG&E claims that DRA focuses on cost minimization without considering test year needs due to new regulatory, safety and maintenance requirements for dams and waterways, and without recognizing cost escalation.

DRA is critical of PG&E's reallocating of funding for projects approved in previous GRCs to cover the cost of other work. DRA asserts that proposed 2014 funding increases related to reallocated work and deferred maintenance should be the responsibility of PG&E shareholders rather than customers. PG&E's recorded spending for 2011 was considerably less than the $159.7 million it had forecasted, and many projects in the 2011 forecast have returned as part of the 2014 forecast. When comparing actual 2011 expenses to the 2011 adopted funding, $15.8 million of expense was reallocated outside of Hydro. DRA claims that this reallocation of funding results in an unreasonable burden to ratepayers by causing them to pay twice for the same activities that were funded in PG&E's prior rate case. DRA proposes that PG&E reallocate funding back to Hydro

Operations and complete the deferred maintenance, without increased ratepayer funding over DRA's recommended limits.

PG&E explains that it re-prioritizes work so that available funding is spent on the highest priority safety, regulatory, reliability and other work for the benefit of its customers. PG&E argues that deferral was appropriate so that emergent, higher priority safety and reliability work could be performed. PG&E denies that embedded costs that are available for projects that were previously deferred. PG&E claims it has limited funds, and must consequently defer and reallocate dollars to address emergent work with higher priority to ensure safety and reliability. PG&E denies that by deferring maintenance or reallocating funding, it is increasing dividends or improving earnings.

PG&E's 2014 Hydro expense forecast is based on a bottom-up identification of specific work to be completed in 2014. PG&E is forecasting more project work in 2014 than it completed in 2011 to ensure safe and reliable operations, and therefore claims funding above 2011 levels is needed for that additional work. PG&E also claims that its forecasts are adequately documented in testimony and workpapers.

6.2.1.2. TURN's Position

TURN's 2014 hydro expense forecast proposal is based on normalization of PG&E's 2011 recorded and 2012-2014 forecasted spending levels. TURN's normalization approach reduces PG&E's 2014 hydro expense forecast by $31.5 million, based on average annualized expense for 2012-2014 of $159.622 million. TURN's 2014 expense forecast would result in a 10% increase, compared to the 31% increase PG&E proposes. If PG&E's 2014 forecast were reduced by the percentage that PG&E's 2011 recorded spending was below its

2011 forecast, that reduction approximates what TURN proposes for 2014 hydro expense.

TURN argues that its proposed reductions are warranted in view of the dramatic increases in PG&E's hydro generation costs particularly since 2007. PG&E's hydro costs grew from 2.4 cents/kWh in 2007 to 3.5 cents/kWh in 2011 and are forecast at 5.5 cents/kWh in this GRC. The 46% increase PG&E requested in 2011 as compared to its 2007 GRC request has been followed by a request in this case for a 57% increase as compared to 2011.

TURN notes that the Commission has relied on alternative forecasting methodologies in past where the magnitude of utility forecasted projects and activities rendered it difficult to perform meaningful comprehensive review. In PG&E's 1999 GRC, for example, PG&E's forecast identified over 200 separate distribution capital projects. Rather than attempt to review each project, TURN reviewed a representative sample and recommended a total adjustment extrapolated from the sampling. The Commission found such an approach reasonable under the circumstances.

TURN believes an alternative forecasting methodology is also appropriate here, in view of the difficulties in performing a comprehensive detailed review of PG&E's forecast. TURN describes PG&E's 2014 hydro forecast as consisting of "a barrage of specific proposals ranging from the microscopic to projects costing tens of millions of dollars. The associated workpapers include tables that extend over multiple pages with hundreds of line items listing specific proposed adjustments." TURN argues that as a result, it is virtually impossible to meaningfully review each and every proposed spending activity or program. As an alternative to reliance on detailed review of every proposed hydro project,

TURN thus proposes its reductions to PG&E's hydro expense and capital forecasts based on an across-the board tops-down approach.

PG&E objects to TURN's tops-down approach to hydro forecasting, arguing that the fact that hydro costs have been increasing does not mean that its 2014 forecasts are unreasonable, or should not be approved. Even with the increasing costs, PG&E argues, its hydro system still provides substantial value, and that its forecasts are properly supported.

If the Commission declines to rely on TURN's four-year average to develop funding for 2014 hydro expenses, TURN proposes as a secondary position specific adjustments to PG&E's expense forecast, as discussed below.

Discussion

We are receptive to considering alternative approaches to simplifying estimates where such an approaches yield reasonable forecasts. We decline, however, to categorically rely on either DRA's or TURN's approach of using historical averages of past spending to forecast funding for 2014 programs and activities. We are concerned that DRA's and TURN's proposed use of past spending patterns may not adequately capture funding needs for new or changing requirements, particularly in view of the increased focus on ensuring safety and reliability measures in this proceeding.

We appreciate the challenges involved in reviewing the huge magnitude of projects and cost increases in spending that PG&E forecasts for 2014. Nonetheless, PG&E has presented a showing based individual MWCs, each of which involve different programs and forecasting issues. PG&E's testimony (Exhibit (PG&E-6), Chapter 2 at 2-54 through 2-97) describes current hydro activities in each of its MWCs, and new work in the 2014 forecast. PG&E's workpapers summarize historic and forecast hydro costs at the MWC level, and

itemize annual cash flows comprising PG&E's forecast. PG&E's workpapers also track embedded and incremental costs from 2007-2014. In order to satisfy ourselves that PG&E' s hydro expense forecasts are reasonable, we believe that separate review of PG&E's support and parties' objections for each of the MWC forecasts is warranted. We thus address hydro expense forecasts in terms of specific MWCs, as discussed below.

6.2.1.3. MWC AB Land Conservation Commitment (LCC) Support

PG&E forecasts $3.06 million in MWC AB to support the LCC, composed of project management, Stewardship Council Support, real estate transaction support, and regulatory application preparation. These costs are to implement the LCC made by PG&E coming out of its bankruptcy consistent with previous Commission decisions. The forecast covers incremental internal costs relating to PG&E's support of the LCC to preserve 140,000 acres of watershed in the Sierra Nevada, Cascade, and North Coast mountain ranges for the benefit of future California.

DRA recommends a reduction of $1.66 million in MWC AB, based on 2011 expense levels. DRA claims that PG&E did not document that current expense funding levels are insufficient to fund 2014 activity.

TURN opposes increased funding for MWC AB. TURN argues that costs related to the LCC should be recovered through a separate application pursuant to the Land Conservation Plan Implementation Account (LCPIA) created by Resolution E-4072, rather than through this GRC. Alternatively, if any funding is authorized in this GRC, TURN proposes that it be limited to 2012 recorded amounts plus a 5% inflation allowance, equal to $2.124 million. This represents a $720,000 increase, equal to 50% more than 2012 recorded amounts.

Discussion

We adopt PG&E's expense forecast for MWC AB and conclude that PG&E adequately justified its forecast. This GRC is the appropriate forum for recovery of these costs. The LCPIA was created for recovery of external costs, such as consultants and reimbursement of costs incurred by the Commission or FERC. PG&E's forecast for MWC AB is for incremental internal costs which would not be included in the LCPIA. Thus, we find that recovery of PG&E's internal costs in this GRC is appropriate, rather than through a separate application.

We find the level of detail underlying PG&E's forecast to be adequate. PG&E described the LCC and explained that forecasted costs are for incremental internal environmental, land management, and legal services. PG&E identified the parcels likely to be the subject of the transactions and described related work. Although full information is not yet available to accurately estimate the number of transactions to implement the Land Conservation Program, PG&E expects 50-to-100 transactions to be executed between 2012 and 2016 for conservation easements and/or ownership transfers.

PG&E identifies a $600,000+ increase between 2011 and 2012 recorded expenses, or a 31% increase over a one-year period. Based on the recorded data, the 2012-2014 trend would be a 62% increase. PG&E's 2014 forecast of $3.064 million is below this trended increase on a percentage basis.

6.2.1.4. MWC AX (Maintain Hydro Reservoirs, Dams and Waterways)

PG&E forecasts $36.8 million for 2014 expense in MWC AX to maintain or restore the safety and reliability of hydro water storage and conveyance systems, including base maintenance of $16.1 million plus $20.7 million for specific

projects. Base work, which includes water conveyance repairs resulting from increased condition assessments, is forecast to increase 8% from 2011 to 2014.

DRA argues that this is MWC is for routine maintenance and doesn't justify the increased funding that PG&E forecasts. DRA recommends a reduction of $15.05 million based on 2011 spending levels. PG&E spent less than the imputed funding for this MWC annually from 2007-2011.

Discussion

We adopt PG&E's 2014 forecast for MWC AX. We conclude that PG&E described in adequate detail the basis for increased funding for MWC AX and identified specific work, including repair and maintenance projects on facilities or waterways. Work in MWC AX includes dam safety, facility risk management, plus maintenance of dams, canals, flumes and penstocks. These water storage and conveyance facilities pose a significant hazard to the public if they are not adequately maintained.

Liberty "found that the risk program has substantially elevated the priority of Power Generation safety programs, along with added funding and resources. Overall dam safety has increased as a result; it is strong and growing stronger."

We conclude that PG&E adequately justified its proposed increase from 2011 to 2014. PG&E's workpapers identify specific projects and work to be done in 2014. The largest cost driver is the volume and cost of specific dam and waterway projects to be performed in 2014. The Asset Management Dam Repair Program and ERM Program are forecast to increase $6.1 million as both programs expand their condition assessments and hazard mitigation.

DRA's proposed 2014 funding level in MWC AX would fund the base work plus only 28% of PG&E's forecasted water storage and conveyance

non-base projects and program work. We conclude that basing the 2014 forecast on 2011spending levels, as DRA proposes, would thus not adequately fund the scope of work necessary for 2014 in this MWC. We also decline to adopt TURN's recommendation for a 24% reduction in MWC AX based in part on its reliance on a four-year average.

We are concerned that DRA's and TURN's proposed funding project and program funding limits for MWC AX could create undue risk on PG&E's ability to adequately maintain dams and waterways. DRA claims that maintenance in MWC AX has been deferred but does not quantify any specific amount of deferred maintenance tied to its proposed reduction for MWC AX.

6.2.1.5. MWC KG (Operate Hydro Generation)/MWC KJ (License Compliance Hydro Generation)

PG&E forecasts $51.5 million for MWC KG (Operate Hydro Generation), a 31.3% increase over 2011 levels (of which 12% represents base work increases). MWC KG covers day-to-day operations and safety work of PG&E's hydro facilities. Factors underlying the forecast include increased public and employee safety, facility security, and employee training. PG&E includes increases for new programs in MWC KG for: (1) a Records Management Initiative called "Documentum" and (2) North American Electric Reliability Corporation (NERC) compliance management.

PG&E forecasts $47.9 million in 2014 expenses for MWC KJ, a 69% increase over 2011 levels, which covers compliance activity related to federal and state mandated license conditions; maintaining recreation, fish and wildlife facilities; environmental monitoring and mitigation; state and federal fees; mandated dam safety programs, plus mandated dam and reservoir maintenance. The largest increase is associated with license implementation from new FERC licenses. The

precise nature and timing of these costs will not be known until mandatory conditions and other FERC requirements are developed and incorporated by FERC into the final FERC license.

DRA recommends a 16% reduction in the MWC KG forecast for 2014 which is $8.441 million below that of PG&E's but is $3.826 million more than 2011 spending. DRA utilized 2012 recorded expenses for its forecast, an increase of 9.75% over 2011 levels. DRA claims the recordkeeping activities included in PG&E's MWC KG forecast are simply prudent recordkeeping that should be part of on-going maintenance already funded by ratepayers. DRA argues that ratepayers should not be responsible for additional costs to address deferred maintenance work.

TURN recommends reducing PG&E's forecast in MWC KG for helicopter use in the Shasta and DeSabla areas which encompass large wilderness regions. PG&E proposes to more than double its 2011 spending on helicopters used to patrol its water conveyance systems to $1,079,000. TURN claims that PG&E did not identify this recommendation in direct testimony, and only mentioned it in two line items within 100 line items for MWC KG in PG&E's workpapers.

TURN recommends that PG&E's estimated cost for helicopters be kept to 2011 levels with a 9% increase for inflation. TURN claims that PG&E failed to adequately address the need for this increase, including whether helicopter usage prior to 2013 had degraded or endangered public safety, or resulted in serious harm that might have been avoided with heavier reliance on helicopter patrols. TURN recommends a funding level of $506,000, representing recorded 2011 costs with a 9% increase for inflation, or $573,000 below PG&E's request.

DRA proposes reductions of $16.251 million to PG&E's MWC KJ forecast (which is still $3.316 million more than 2011 spending). DRA utilized a

three-year average (2010-2012) for its 2014 forecast. DRA claims that PG&E's historical expenses include embedded costs for these pending licenses. DRA believes that PG&E received sufficient authorized funding during 2007-2011 and that embedded historical funding can be reallocated and utilized to address PG&E's proposed activities and expected FERC licenses in 2014.

TURN also disputes PG&E's forecast of FERC fees included in MWC KJ. TURN forecasts $11.409 million, an increase of $3.2 million (40%) from the 2011 recorded figure but a reduction of $855,000 from PG&E's request. These costs are largely out of PG&E's control, are set by FERC, and vary in part due to water conditions.

FERC fees include administration and land use components. The administration component allocates the costs that FERC and other federal agencies spend administering hydro facilities to all FERC licensees based on installed capacity and energy produced the prior year. PG&E claims that FERC and other federal agency administration costs, and unit costs, have increased an average of 6% per year from 2007 through 2011. Unit costs are allocated to the licensees by their annual generation. There are also land use fees. FERC and the US Forest Service continue to evaluate their land use fees, which for PG&E make up about 10% of total FERC fees.

PG&E's forecasts $9.258 million for safety items in MWC KG and KJ which includes $2.8 million in two blanket projects. TURN recommends a smaller 2014 forecast figure is $2 million below PG&E's request. TURN claims that PG&E's workpapers offer no justification for the increased funding sought for the two blanket projects, and no explanation of what might be done with the money.

Discussion

We reduce PG&E's combined forecast for MWC KG and KJ by $2 million, as proposed by TURN, relating to proposed safety programs. TURN's adjustment is the approximate midpoint between PG&E's request and 2011 recorded costs escalated with inflation. Adopting this reduction in PG&E's forecast is warranted in view of the lack of detail justifying the increase requested. This reduction still provides increased funding of $2.3 million, or nearly 50%, over comparable 2011 spending levels. PG&E claims it justified its proposed safety-related funding in MWC KG and KJ, with discussion in testimony and details of the related work in planning orders.[62] PG&E's testimony, however, provides only a general description of the operations and activities classified as safety-related, but does not demonstrate the reasonableness of its proposed five-fold increases in spending levels between 2011 and 2014. PG&E's workpapers show multiple line items comparing recorded and forecasted amounts, but without analysis evaluating benefits in relation to costs. Liberty stated in its safety review that the rationale and justification for PG&E's aggregate spending level "remain clouded." Given these considerations, we find TURN's proposed reduction reasonable.

We also adopt TURN's recommended reduction of $855,000 to PG&E's forecast for FERC fees. We agree with TURN that a five-year average of recorded costs is an appropriate forecasting basis. PG&E provided no data to back-up its claim of a 6% cost escalation trend from 2007-2011, and did not indicate the amount of a purported 2011 rebate.

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[62] Exh. 58 (PG&E-21) at 2-78, lines 16-19.

We decline, however, to approve DRA's proposed reduction to MWC KJ of $16.25 million, based on 2010-2012 spending levels. We conclude that DRA's forecast would go too far in reducing funding and would not adequately reflect the scope of 2014 requirements. DRA's funding level would only cover regulatory required fees (totaling $12.6 million), plus 87% of PG&E's forecast of ongoing regulatory required base work (e.g., compliance with hydro licenses and maintaining fish, wildlife facilities, and recreation facilities.) Inadequate funding levels could lead to license violations, and potentially jeopardize operation of a portion of the hydro portfolio.

We also decline to adopt DRA's proposed reductions for MWC KG. DRA's proposed reductions in the MWC KG forecast would mean deferral of 21 safety projects and programs, including records management; NERC compliance; lock replacements; fire safety projects; waterway public safety improvements; apprenticeship training programs; lockout/tagout improvements; ongoing and enhanced recordkeeping efforts; and grounding repairs at four powerhouses.

Costs have been increasing in MWC KG due to more complicated FERC operating rules, California Independent System Operator (CAISO) and other regulatory requirements; and increased employee training and safety programs. We conclude that reliance on 2012 spending levels would not adequately fund the programs for 2014.

We approve PG&E's requested funding for increased use of helicopters, particularly given the heightened focus on safety in this proceeding. PG&E's increased deployment of helicopters will improve visibility of public use of rivers in order to warn recreationists in advance of flow changes, to improve surveillance, and to perform construction and maintenance of facilities in the

remote Shasta and DeSabla areas. Increased helicopter use will improve response times to detect and remedy failures in these hydro facilities.

6.2.1.6. MWC KI (Maintain Hydro Structures, Roadways and Infrastructure)

PG&E forecasts $14.6 million for 2014 for MWC KI for routine facility maintenance for hydro structures, roadways and infrastructure. Base work in MWC KI is forecasted to decrease from 2011 to 2014. Specific increases include $4.1 million for 20 non-routine painting, paving, and roof repair projects to extend asset life and to avoid future infrastructure maintenance and replacements.

DRA recommends a 24% reduction of $3.375 million in the MWC KI forecast, based on 2011 spending levels. DRA argues that PG&E's ratepayers should not fund routine and on-going maintenance work twice because PG&E's management decided to defer the work. Based on Commission policy regarding deferred maintenance, DRA believes PG&E's shareholders (not ratepayers) are responsible for deferred maintenance costs. DRA's estimate of $11.150 million utilizing PG&E's 2011 expense levels is the highest recorded figure for the six-year period (2007-2012).

TURN claims two blanket projects in MWC KI are duplicative, and recommends that the projects be removed, reducing PG&E's 2014 forecast by $1.297 million.

PG&E denies these costs reflect duplicative work, arguing that the Hydro forecast consists of specific projects in the near term and programmatic work in outer years to maintain, among other things, the roads necessary to access PG&E's facilities. PG&E claims even though it has not fully scoped every project

in MCW KI, its forecast of programmatic funding covers ongoing work necessary to maintain the hydro system.

Discussion

We reduce PG&E's forecast for MWC KI to remove the two blanket projects in the amount of $1.297 million as proposed by TURN. These projects cover programmatic work that has not been scoped or prioritized, and is in addition to increases for division-level forecasts for specific projects. We are not convinced that PG&E requires this additional funding cushion in 2014 to adequately maintain and restore its hydro system infrastructure. Even without these two blanket projects, PG&E's 2014 forecast is still an increase of 19.5% from comparable 2011 levels. We conclude that this magnitude of increase should be sufficient to enable PG&E to perform necessary maintenance and restoration of its hydro system.

We decline, however, to approve DRA's proposal to limit 2014 funding to 2011 levels. We conclude that DRA's proposed funding would be insufficient to cover the increased scope of programs, including non-routine painting, paving, and roof repair projects to extend asset life and to avoid future infrastructure maintenance and replacements. DRA has not identified how its arguments regarding deferred maintenance specifically apply to the MWC KI forecast.

6.2.1.7. MWC JV (Maintain IT Applications and Infrastructure)

PG&E forecasts $3.4 million in 2014 expenses in MWC JV for multiple IT projects planned for 2014. PG&E developed its forecast by estimating the expense portion associated with multiple IT improvement projects planned for 2014. Two of these projects are RMI-Documentum and Asset Management/Condition Based Maintenance. These projects will develop new

capabilities in their respective areas and are unrelated to ongoing records management activities.

DRA recommends a $2.467 million reduction to eliminate funding for RMI-Documentum and PG&E's Asset Management/Condition Based Maintenance (Asset Management) program and normalizing eight additional IT projects. DRA claims there is insufficient support for PG&E's estimates.

DRA claims that no cost savings or avoidance is forecast for Documentum and that PG&E should have already been organizing and maintaining its records. DRA contends that PG&E has embedded funding for this recordkeeping activity and no additional funding is required.

DRA references the Commission's PSEP decision (*i.e.,* D.12-12-030) as a further basis for the proposed reductions. PG&E denies that the findings in D.12-12-030 regarding its transmission system have applicability to its proposal here. PG&E claims that it is in compliance with document retention requirements applicable to Hydro Operations.

While compliant with existing record-keeping requirements, PG&E argues that the status quo is inefficient and does not reflect industry best practices. Existing hydro record-keeping system is largely paper-based. PG&E explains that Documentum is not to fix past recordkeeping deficiencies or to come into compliance, but to replace antiquated paper-based and uncoordinated electronic data base systems with a single state of the art document management system. PG&E claims that DRA's expense recommendations also fundamentally contradict its capital proposals. PG&E's funding request includes $300,000 as the forecasted expense of its Project Portfolio Management Tool (PPMT) that PG&E describes as better enabling long-term planning and management efforts, including cost and prioritization of the planned work.

Discussion

We adopt PG&E's forecast for MWC JV. PG&E has been developing and implementing an enterprise-wide records management archival foundation for some time. In the 2011 GRC, PG&E requested funding to build an IT records management environment around a tool called Documentum as the foundation for an enterprise-wide data archival and records management program. PG&E is now building the Documentum tool, and forecasts funding for data conversion from various hard and electronic documents to Documentum. PG&E's 2014 forecast includes the expense portion of the Documentum project. This funding enables PG&E to perform the data conversion from numerous and various hard and electronic documents to Documentum. We also conclude that PG&E's showing justifies funding of the Asset Management condition based maintenance IT toolset.

6.2.2. Hydro Capital Expenditures Overview

PG&E presents a Hydro capital expenditure forecast of $293.05 million for 2012 (based on 2012 actual), $260.96 million for 2013, and $344.66 million for 2014. Key drivers for capital cost increases are: (a) upgrades and modifications to dams, penstocks and waterways as a result of changing FERC and Division of Safety of Dams guidelines, as well as PG&E's assessment of the facilities; (b) turbines and generator projects to ensure safety and reliability.

There are no major disputes over PG&E's 2012 and 2013 capital forecasts. DRA adopts as reasonable all recorded Hydro 2012 capital expenditures (which is an increase of $30 million over PG&E's original 2012 capital forecast Hydro). PG&E accepts DRA's proposed 2012 capital funding level. DRA also finds Hydro's 2013 capital forecasts, with the exception of MWC 2F for IT projects, to be reasonable.

DRA, TURN, and Energy Producers and Users Coalition (EPUC), however, all propose reductions to PG&E's 2014 hydro capital forecast. (Since EPUC's proposals are limited to specific MWCs, we separately address EPUC's disputes later in a separate discussion of MWCs.) PG&E's 2014 hydro capital forecast, together with the DRA, TURN, and EPUC proposed 2014 capital reductions are summarized as follows:

		$ in millions		
		Forecast	**Proposed Reductions**	
Description	**MWC**	**PG&E**	**DRA**	**TURN**
Tools and Equipment	05	$2.91	-	
Licensing and License Conditions	11	45.18	-	
Environmental Projects	12	8.32	-	
IT Applications	2F	14.05		
Safety & Regulatory	2L	49.61		
Hydro Generating Equipment	2M	121.70		
Reservoirs Dams & Waterways	2N	86.24		
Structures, Roads, & Infrastructure	2P	16.65	____	____
Total		$344.66	-77	-26.48

6.2.2.1. DRA's Position

DRA proposes a $77 million reduction in PG&E's 2014 capital forecast based on forecasting approaches that differ from PG&E's. DRA proposes a global 14% reduction for IT forecasts based on concerns about the Concept Estimating Tool.

DRA proposes exclusion of certain projects from the 2014 capital forecast where project spending occurs mostly after 2014. Several hydro projects become

operational in 2014 (although spending continues after that point). Other projects become operational in 2015-2016, although spending starts in 2014. DRA's recommended reductions in capital MWCs 11, 12, 2F, 2L, 2M, 2N and 2P are solely based on this capital spending timing, resulting in a 2014 reduction of 22%, and an effective 2014-2016 capital reduction of 29%.

PG&E objects to such exclusions. To the extent spending on projects starts in 2014, PG&E believes the related costs should be in the 2014 capital forecast. PG&E claims that removing these projects from the 2014 forecast may result in insufficient funding for certain work to progress in a timely manner.

PG&E claims that DRA's forecast approach appears random, without explanation of why different time intervals are used for forecasting various MWCs. PG&E claims that DRA's reliance on historic spending fails to consider the funding for new regulatory requirements, such as safety and maintenance for dams and waterways. DRA also excludes price inflation between 2011 and 2014.

6.2.2.2. TURN's Position

TURN proposes reductions to PG&E's hydroelectric capital expenditures based on three principal issues. The first of these issues relates to PG&E's prioritization of project spending. We address that issue here. We address TURN's other capital spending issues in discussing the specific MWCs where the issues arise.

TURN proposes a $27.6 million capital reduction ($12.5 million weighted average), to exclude 2014 capital funding for projects identified as low priority. PG&E ranked and prioritized over $1.5 billion of hydroelectric capital projects (covering 2012-2016). Each capital project was assigned a priority score on a ranking scale of 1-2000. Despite efforts to prioritize and rank projects, TURN claims that PG&E proposes that ratepayers fund everything on its list regardless

of priority. Of the $1.5 billion of projects that were not IT- or license-related, $406 million (or 27% of funding) scored 20 or less on a scale of 2000. More than $100 million had a score of zero. PG&E ranked 69 projects as low-scoring and low-priority projects, (i.e., scored below 20). In 2013-2014, $43 million worth of projects scored a priority ranking between zero and 20.

PG&E claims that TURN's approach ignores the dynamic nature of PG&E's prioritization process whereby priorities change throughout the GRC cycle. PG&E claims that TURN's proposal would significantly reduce the amount available for the Hydro projects to a figure lower than 2012 actual expense spending. PG&E claims the projects identified with a low priority scoring are still essential to maintain the safe and reliable operation of the Hydro system in 2014 and beyond. PG&E argues that a low-scoring priority project forecasted during the 2014-2016 cycle does not mean that project does not need to be completed. Rather, the ranking score simply means the work does not have to be completed immediately. As the time for implementation of projects approaches, the priority ranking score increases.

Discussion

We decline to categorically adopt DRA's proposed exclusions of capital expenditures based on whether underlying project spending occurs mostly after 2014. We conclude that DRA's proposal does not adequately account for the effects on reliability and safety of deferring, reprioritizing, and/or delaying projects merely because they involve multi-year spending plans. Some of the projects that DRA seeks to exclude are scheduled to be operative in 2014. For projects, however, forecast to be operative in 2015, 2016 or beyond, excluding those expenditures would not change 2014 revenue requirements. As PG&E explains, however, multi-year programs and projects need to be in the 2014

capital spending forecast to be completed within the three-year GRC period. Even if multi-year projects are not operational until later, the planning, design and material procurement needs to start within this GRC cycle to avoid unwarranted deferral.

We adopt DRA's proposed 14% reduction for IT programs, however, based on use of PG&E's Concept Cost Estimating Tool based on our discussion at Section 7.8.2.

We also conclude that TURN's proposed reduction of PG&E's hydro capital cost forecast based on exclusion of low-priority projects is reasonable and adopt it. Given the magnitude of projects and funding increases proposed, and given the limits in PG&E's showing in justifying spending on hydro projects in relation to benefits, it is challenging to comprehensively confirm PG&E's claims that every dollar of its forecast is warranted.

In this regard, the Liberty Report observes that PG&E includes "volumes of details on individual projects" relating to Power Generation, with a "high level conceptual comments on the one hand, and thousands of pages of supporting detail on the other." Liberty concludes, however, that "[n]either is particularly helpful or appropriate for the evaluation of aggregate spending levels." Liberty was unable to determine what process or rationale PG&E used to prioritize proposed projects or spending levels. (Liberty Report at 78 and 79) The closest that Liberty could obtain as a rationale was PG&E's statement that funding targets were based on assessed risks of rescheduling work to future years versus the adequacy of resources to successfully undertake the work. Liberty concluded PG&E's explanations lacked "a convincing rationale and justification for a spending level substantially beyond previous levels."

As noted by EPUC, the vast majority of PG&E's forecast capital expenditures have no Job Estimate or Project Justification documentation. Out of the $224 million in proposed capital expenditures for 2014, 65% of the projects, representing $140 million of proposed expenditures, have no Job Estimate or Project Justification and a status of not applicable.

Given the lack of a more definitive showing regarding the cost/benefit trade off, particularly for lower priority projects proposed by PG&E, we conclude that TURN's proposed adjustment offers a reasonable curb on PG&E's spending approvals while still enabling PG&E to provide safe and reliable service.

TURN's proposed reductions apply to one-half the costs of PG&E's low-scoring blanket projects, one-half the costs of individual projects with scores of 11-20, and all costs of individual projects that scored 0-10. If funding of such projects were essential to maintain safe and reliable operation of the Hydro system in 2014 and beyond, we believe that the projects and programs in question would reasonably be expected to score higher than 0, 10 or 20 on a scale of 2,000.

Contrary to PG&E's claims, we do not believe that adopting TURN's approach ignores PG&E's prioritization process. Rather, TURN's approach allocates the risks and uncertainties of PG&E's prioritization process within the discipline of test year ratemaking. While project priorities periodically change, such changes can occur in either direction. Projects with a lower priority ranking may rise in priority, but projects with a higher ranking may decline in priority over time. Adopting TURN's proposal does not preclude PG&E from exercising discretion to continue to reprioritize spending within available funding as changing conditions warrant.

Also, we also are not persuaded that TURN's adjustment would result in PG&E only funding projects that are immediately necessary. TURN's adjustment is based on PG&E's own priority ranking process, which incorporates several criteria, not just that of immediate need. PG&E's work is prioritized using the following characteristics: Justification, Asset Criticality, Risk (vulnerability and health), Priority, Urgency, Other Considerations, and Outage Package Name. There is no basis to conclude that TURN's approach based on PG&E's own ranking process would require PG&E to fund only projects that are immediately necessary without regard to changing priorities over time.

TURN's estimate from its proposed methodology reduces PG&E's capital budget by $27.6 million. But, our calculations are different from that of TURN's. Applying TURN's proposed methodology of reducing one-half the costs of PG&E's low scoring blanket projects, reducing one-half of individual projects with scores of 11-20, and reducing all costs of projects with scores of 0-10, we calculate a reduction of $27.023 million to PG&E's capital budget. Accordingly, we reduce PG&E's capital budget by $27.023 million capital reduction ($12.5 million weighted average), to exclude funding for projects identified as low priority, as proposed by TURN. Our calculations, in addition to the MWCs for which the reductions are applied, are shown below:

MWCs	0-10 Projects (Remove 100%)	11-20 Projects (Remove 50%)	Total Reduction
5	$200	$2,110	$1,255
11	$125	$	$125
12	$	$1,340	$670
2L	$955	$2,000	$1,955
2M	$7,197	$11,317	$12,855.50
2N	$2,324	$11,986	$8,317
2P	$883	$1.925	$1,845.50
Total			**$27,023.00**

We address other disputed issues relating to hydro capital expenditures by specific MWC, as discussed below.

6.2.2.3. MWC 2F (Building Information Technology Applications and Infrastructure)

PG&E's capital forecast is $14.05 million in MWC 2F (Building Information Technology Applications and Infrastructure), covering 12 IT projects to support hydro operations and to upgrade or replace infrastructure and Application systems at the end of their useful life. Two of these projects are Records Information Management Documentum® and Asset Management/Condition Based Maintenance.

DRA recommends a $1.967 million reduction based on applying its 14% reduction in IT capital based on general concerns regarding PG&E's Concept Estimating Tool. TURN recommends no funding for PG&E's PPMT based on the belief that this tool is not useful nor is it being used.

Discussion

We conclude that PG&E's proposed IT projects including the Records

Information Management Documentum® and Asset Management/Condition Based Maintenance have been reasonably justified and should be funded. We thus adopt PG&E's forecast for MWC 2F, except to reflect TURN's exclusion of low-priority projects, as discussed above, and to reflect DRA's adjustment applying its 14% reduction in IT capital based on concerns regarding PG&E's Concept Estimating Tool. We decline to adopt TURN's proposal for no funding of PG&E's PPMT. As PG&E explains, the PPMT is an ongoing project designed to customize the management of individual projects from authorization through completion, and will allow changes in project cost, scope and schedule to be reflected in its Long Term Plan process.

6.2.2.4. MWC 2L (Install/Replace for Hydro Safety and Regulator Requirements)

PG&E forecasts capital expenditures of $49.6 million in MWC 2L in 2014 for facility safety work plus other work required by various regulatory bodies. The forecast includes $24.9 million for dam safety, $9.8 million for employee safety, $8.9 million for public and waterway safety and $6.0 million for NERC Security, and Records Management.

DRA recommends a $14.0 million decrease to the 2014 capital forecast, by excluding funding for three projects: Arc Flash Remediation, Dam Safety Instrumentation Automation, and System Protection and Controls. DRA believes these projects should be rescheduled beyond 2014 since their forecasted spend is weighted towards 2015-2016.

DRA also recommends no funding for the Pit 4 Unit 2 turbine upgrade project. Four major capital projects are planned at Pit 4 powerhouse in order to restore it to reliable operation over the 2014 GRC timeframe and beyond. PG&E states that the existing turbines have unacceptable vibration levels and degraded

performance. The poor turbine performance will continue to occur if this turbine work is deferred. DRA also recommends not funding 11 minor reliability projects at eight different powerhouses (*see* Table 2-2, line 13).

Discussion

We adopt PG&E's forecast for MWC 2L, except for the exclusion of low-priority projects as proposed by TURN and as discussed above. We decline to adopt DRA's proposed reductions to MWC 2L. We conclude that DRA has not justified the deferral of 2014 spending for these projects based on cash flow timing for the reasons as discussed earlier. We also decline to adopt DRA's proposal of no funding for the Pit 4 Unit 2 turbine upgrade project. Deferring this reliability work would create an unacceptable risk of performance degradation.

6.2.2.5. TURN's Proposed Reductions Relating to Three Capital Spending Projects

TURN proposes reductions to PG&E's capital spending budgets for work related to the three projects: (1) Crane Valley Dam rebuild, (2) Lake Nora Walkway, and (3) Helms Cooling Water Control Replacement projects. Recorded costs for these three projects were significantly higher than forecasted. TURN claims the cost increases were due in large part to either project mismanagement or making the wrong management call. PG&E proposes to include all recorded costs for these projects in rate base for recovery from ratepayers. Rather than permit the utility to have an opportunity to earn its full authorized return on equity on such projects, TURN recommends reductions of a $15.8 million in PG&E's 2012 forecast capital and a $18.1 million in PG&E's 2013 forecast capital.

6.2.2.5.1. Crane Valley Dam Rebuild

TURN recommends a disallowance of $10 million, from $127.428 million to $117.428 million, for the Crane Valley Dam seismic upgrade project. This project involved raising the dam crest and placing additional rock on the dam to stabilize it in the event of an earthquake. Due to the volume of rock needed, initial engineering analyses determined that developing a rock quarry locally was safer, less costly, and environmentally preferred to trucking the rock in from quarries located away from the site.

During construction, however, geological site conditions proved different from PG&E's original assessment. The amount of unsuitable rock above the bedrock was more than pre-construction tests indicated. In response, some rock was trucked onto the site, in addition to using the local quarried rock.

TURN claims that these quarry-related problems were largely products of PG&E management action or inaction. PG&E decided to go forward without recognizing that the utility itself lacked sufficient experience in quarry development and operation, and had selected a contractor who lacked the necessary expertise in these areas. By seeking full cost recovery of the amounts spent on this project, 100% of these risks of management mistakes or inaction get assigned to ratepayers. TURN argues that some portion of costs is the product of imprudence and should be excluded from rate recovery. TURN argues PG&E should have known prior to construction where the sound rock was located and how much was economically available to quarry onsite.

Discussion

We decline to disallow funding for this project. We recognize that PG&E incurred higher costs as a result of having to quarry in additional rocks, but we are not convinced that PG&E's actions or inactions justify a disallowance of costs.

PG&E did detailed engineering analysis and geotechnical assessments and chose to develop a quarry as the lowest cost, least environmentally detrimental alternative. PG&E could have spent additional time and money doing more pre-construction subsurface drilling and hiring expert quarry consultants. The record does not reveal, however, whether additional time and money invested prior to construction would have necessarily resulted in the total time or cost of the project being less. We conclude that PG&E's planning was reasonable based on information it knew or could reasonably have learned at the time.

6.2.2.5.1.1.Lake Nora Walkway

For the Lake Nora Walkway Project, TURN recommends using the actual project cost of $1.533 million as the starting point, and disallowing $375,000 (i.e., $350,000 of 2011 costs plus allowance for funds used during construction for a total of $1.158 million). Ratepayers would still pay $750,000 above the original forecast, and $250,000 above the January 2011 revised forecast.

PG&E replaced the walkway in Lake Nora, the sub-structure located in the sediment of the lake, plus replacing the walkway boards to provide safe employee access to the dam intake. All construction activities in and around reservoirs and waterways are subject to strict water quality regulations. Hydro designed and permitted a dewatering plan that would safely allow construction to proceed in the lake with insignificant, regulatory-allowed levels of turbidity downstream.

During the first attempt at draining Lake Nora, water quality monitoring showed the level of turbidity was too high, and construction stopped. PG&E thus had to design and permit a new dewatering plan. The cost of the project increased due to PG&E's initial failed attempt to drain the lake. The initial attempt caused turbidity concerns, leading to construction delays, postponement

of construction to wait out the rainy season, and then another but different attempt at draining the lake. TURN argues PG&E should have known prior to construction that the permitted dewatering plan was deficient.

Discussion

We decline to disallow funding for this project. We recognize that PG&E incurred higher project costs as the result of PG&E's initial failed attempt to drain the lake. The site conditions and regulatory oversight made this project more complex and difficult than originally expected. At the time the engineering alternatives were developed and the permits obtained, however, PG&E chose the less costly method as it was determined to be capable of meeting the water quality objectives. PG&E believed at the time that the dewatering plan was sound. We are not persuaded that PG&E's actions were imprudent based on information available at the time, or that a cost disallowance is warranted.

6.2.2.5.2. Helms Upgraded Cooling Water System

PG&E began the Helms Cooling Water System upgrade in 2009. In mid-2010, this project was revised to high priority. However, given all other work at Helms and in Hydro, PG&E ranked this project below the funding cut line and did not fund it in 2011.

For the Helms Cooling Water System upgrade, the project received funding in 2012, and was included in the 2014 GRC forecast for $2 million, and was reauthorized in March 2012 for $2.1 million. TURN recommends limiting cost recovery to $887,000, equal to the original $812,000 estimate from 2010 plus three years of inflation at 3%. TURN proposes the disallowance as a proxy for the likely outcome had PG&E pursued the project under a more industrious construction schedule rather than the pace it displayed in replacing the failed

controls so the pumps might stop running continuously. It also avoids assigning to ratepayers the full amount of costs incurred because the project as originally designed did not fit within the available space. TURN's approach represents a disallowance of $502,000.

TURN claims that PG&E appeared to be dilatory throughout the process. PG&E disagrees, arguing that it identified the equipment problem early and diligently worked through the scoping, design, authorization, and budgeting processes until adequate funding was obtained.

Discussion

We decline to disallow funding for this project. We are not persuaded that PG&E acted imprudently. Helms is an underground powerhouse with all the generating equipment located in a large multi-leveled cavern. Even so, space is limited due to the size and location of other equipment, piping and conduits, and maintenance access and laydown area requirements. As explained by PG&E the ultimate size, location, space requirements, and potential interference points of the variable frequency drive (VFD) could not be determined until the 90% design review. At that point, PG&E decided that it was cost prohibitive to make room for the VFD, and so a smaller alternative was designed and procured. Based on PG&E's explanations, we believe that the project was managed in a prudent manner.

6.2.2.6. MWC 2M/2N/2P (Install/Replace Hydro Generating Equipment / Reservoirs, Dams and Waterways/ Hydro Structure, Roadways and Infrastructure)

PG&E forecasts the costs of hydro equipment, waterways, roadways, and infrastructure in MWCs 2M, 2N, and 2P. PG&E forecasts 2014 capital expenditures of $121.7 million in MWC 2M for installation/replacement of

unreliable, obsolete, and degraded hydro generating equipment, including $60.3 million for Generator Systems, $49.1 million for Turbine Systems, and $12.2 million for Protection, Controls, and Ancillary Electrical Equipment. The Turbine System projects will also improve operating efficiency.

PG&E forecasts $86.2 million in MWC 2N to modify and replace hydro dams and appurtenant facilities, including $39.2 million for canals, $24.8 million for penstock systems, $17.6 million for dams, and $4.5 million for flumes. PG&E claims the increased funding is required to enhance public safety, improve water conveyance reliability, and improve the condition of dams, reservoirs, and waterways. The ongoing Asset Management and ERM processes are forecast to increase spending in this MWC as increased facility assessments identify weaknesses in PG&E water storage and conveyance facilities.

PG&E forecasts $16.652 million in MWC 2P for 32 different infrastructure projects and programs. Major elements include starting construction on the Auburn hydro service center replacement (forecast of $6.0 million) and rebuilding the deteriorated Bucks Creek portal road and the Caribou access road (forecasts of $3.0 million and $1.5 million respectively). Other infrastructure projects include road, bridge, valve house, roof and telecommunication improvements, plus the removal of abandoned buildings.

DRA proposes a $16.3 million decrease to PG&E's MWC 2M forecast for 2014, removing five major and 11 minor projects where at least 50% of spending is in 2015-2016. DRA believes these projects should be rescheduled based on their forecasted spend being weighted towards 2015-2016.

DRA recommends a $32.6 million decrease by removing five major and five minor projects where forecasted spending is weighted toward the 2015-2016 period. DRA also proposes that the Drum Canal project be deferred based on

pre-2014 spending above $1 million and a 2014 cost to total cost spending ratio of 0.30. PG&E opposes DRA's reduced funding recommendation for the Drum Canal Gunite Work. The Drum canal consists of over nine miles of canals, flumes and tunnels. Each year, the most degraded sections of the canal are replaced. PG&E forecasts an operative date of October 2012 with annual capital costs going through the end of the GRC term. This work is required to deliver consumptive water downstream. Failure of these asset can results in significant third party and environmental damage.

DRA recommends a $6 million decrease to PG&E's forecast for MWC 2P as a result of removing the Auburn hydro service center project because the forecast spending pattern is weighted toward 2015-2016. PG&E claims DRA's proposed funding level would unreasonably limit investment in dam and water conveyance facility safety projects and programs throughout the 2014 GRC cycle. The Auburn facilities are in poor condition and are situated in residential areas. PG&E claims the project will improve public safety, employee safety, community relations, and operational efficiency. DRA's proposal essentially defers the completion of this work for at least three years due to the attrition ratemaking in 2015 and 2016. PG&E opposes delaying this project out of the 2014 GRC cycle in view of the degraded condition of the Auburn service center.

EPUC addresses MWC 2M, 2N and 2P together in recommending a funding reduction totaling $28.8 million in 2012, $37.1 million in 2013, $67.9 million in 2014, $139 million in 2015, and $176.3 million in 2016, covering MWC 2M, 2N, and 2P. EPUC claims that despite significant increases in MWC 2M, 2N and 2P forecasts, PG&E did not offer sufficient justification. EPUC argues that since PG&E currently operates its hydro system reliably, recorded expenditures should be the foundation for 2014 funding for MWC 2M, 2N and

2P. EPUC proposes a forecast for MWCs 2M, 2N, and 2P based 2009-2011 recorded data, less emergent work, plus PG&E's forecast of reliability work at units with below industry average performance. EPUC also proposes that the Commission authorize additional funds for hydro projects with Forced Outage Factors higher than the industry average. EPUC's proposed reduction in PG&E's capital expenditure forecast for 2012-2016 totals $449 million. EPUC claims its proposed reductions provide a reasonable level of capital expenditures relative to historical levels which resulted in PG&E's hydro system being more reliable than the industry average.

EPUC asserts that since PG&E is under no obligation to perform forecasted work in MWCs 2M, 2N or 2P, that the most logical source to determine forecast capital is recorded capital. PG&E argues that reducing capital expenditures in all three identified MWCs as proposed by EPUC will not necessarily increase outages at PG&E's Hydro facilities. PG&E responds that FERC requires its licensees to maintain all licensed facilities in good working order. PG&E claims that EPUC's proposal would lead to degradation of the Hydro system by underfunding safety and reliability projects.

PG&E claims that EPUC's proposed reduced funding for water storage and conveyance facility improvements unreasonably put PG&E employees and the public at risk, jeopardizes the delivery of consumptive water to farms and residences, and would create significant environmental damage if any of these facilities fail in service.

PG&E claims EPUC's comparison of PG&E Hydro facility outage rates to the industry average is an apples-to-oranges comparison. PG&E's Hydro system largely consists of individual units, rather than large powerhouses with multiple units. Thus, an outage of PG&E's facilities will have a more substantial impact

on customers than an outage at a multi-unit facility where water can be used in another unit. Given the unique design of PG&E's hydro system, PG&E seeks to minimize outages to ensure that customers receive the greatest value. Customers would incur greater costs if PG&E's hydro facilities were less reliable.

Deferral of work in MWC 2P (Structures, Roads and Infrastructure) does not directly adversely affect generation in the near term. Infrastructure projects in MWC 2P do not present high public hazards or regulatory non-compliance risk, Consequences of an infrastructure failure are generally minor. Rescheduling may lead to greater repair costs in the longer term. Nevertheless, PG&E argues that infrastructure deficiencies cannot be rescheduled indefinitely, and that its forecast balances the near term need to complete ongoing safety and reliability work with the long-term need for a sustainable level of investment in infrastructure.

Discussion

We adopt PG&E's forecasts for MWC 2M, 2N, and 2P, except for the previously discussed reductions in low-priority projects that we adopt, as proposed by TURN, and as reflected in Table 6-11B of PG&E's opening brief.

Since we are adopting TURNs' proposal to eliminate low-priority capital hydro projects from the PG&E forecast, we reduce PG&E's forecasts accordingly, as reflected in Table 6-11B of PG&E's opening brief. The adoption of TURN's adjustment to eliminate low-priority projects addresses some of the same concerns raised by EPUC regarding PG&E's justification for the level of expenditures being proposed. We conclude, however, that EPUC's proposed level of capital spending reductions for MWC 2M, 2N, and 2P goes too far in potentially adversely impacting PG&E's ability to provide safe and reliable service. As noted by PG&E, EPUC's proposed funding reductions of

$449 million for 2012-2016 would mean deferral of 89 projects which started in 2012. In addition, 56 projects starting in 2013 and 104 projects starting in 2014 would be deferred. In view of the potentially adverse effects on PG&E's ability to provide safe and reliable service, we thus decline to adopt EPUC's proposed level of reductions for MWC 2M, 2N, and 2P.

Also as previously discussed, we decline to rely on DRA's cash flow methodology as a basis for reducing PG&E's forecast of hydro expenditures in MWC 2M, 2N, and 2P.

6.2.2.7. MWC 11 (Hydro Licensing and License Conditions)

PG&E 2014 capital forecast is $45.176 million for MWC 11 which includes investments for new long-term FERC licenses for hydro facilities upon expiration of previous licenses; FERC license amendments to reflect major changes in license-related projects/facilities and operations; and to install/construct new capital equipment or facilities to comply with FERC or new license conditions. PG&E's forecast includes $13.0 million for FERC Balancing Account license conditions, $16.5 million for ongoing license conditions and $15.6 million for FERC Balancing Account licensing.

TURN proposes reductions in MWC 11 of ($50.6 million total, $32.8 million weighted average to reflect more accurate in-service dates for a number of projects for which FERC relicensing has been delayed PG&E's capital spending on hydro projects is tied to FERC relicensing, with the costs going from construction work into plant in service accounts once the relicensing occurs. TURN proposes to reduce the 2014 end of year gross plant by $50.6 million due to FERC's delayed issuance of new licenses for Poe, Upper North Fork Feather River (UNFFR), DeSabla-Centerville, and McCloud-Pit projects.

DRA proposes reductions of $4.9 million by removing 2014 funding for three projects. DRA argues that these projects should be postponed beyond 2014 because over 90% of the spending is for 2015-16. PG&E argues that funding for these projects should not be reduced.

Discussion

We adopt TURN's recommendation to change the in-service dates for projects for which FERC relicensing has been delayed. TURN's proposed adjustment of the in-service dates for the Poe, UNFFR, DeSabla-Centerville, and McCloud-Pit projects accurately reflects the status of relicensing, as compared to PG&E's original forecast. Applying the changes to the in-service dates, TURN recommends a reduction of $50.6 million to 2014 end-of-year plant. But our calculations show a different result. After applying the in-service dates as proposed by TURN, using PG&E's 2012 recorded numbers as the adopted forecast for 2012, and incorporating Allowance for Funds Used During Construction (AFUDC) and escalation rates, our calculations show a reduction of $40.293 million. Our calculations reflect the adjustments to the in-service dates for the Poe, UNFFR, DeSabla-Centerville, and McCloud-Pit projects to reflect delayed issuance of new FERC licenses, as proposed by TURN.

PG&E offers no convincing reason, however, for ignoring more recent and more accurate data for adopting a 2014 forecast for MWC 11. PG&E argues that changes in FERC licensing schedules are an inevitable development of a multi-year GRC process where PG&E's forecast was prepared in early 2012. PG&E claims that it is unreasonable to reflect TURN's proposed updates while ignoring other updated information that would increase PG&E's forecast. PG&E makes general reference to other updated information, but identifies no specific information that would contradict the adjustments suggested by TURN's. We

conclude that TURN's proposed adjustments to the in-service dates of specific projects in MWC 11 offer a more accurate forecast and adopt it. Thus, by our calculations, we reduce MWC 11 by $40.3 million.

We recognize that the changes in the forecast over the course of the proceeding illustrate the need for a separate procedural vehicle to address the uncertainty relating to FERC relicensing costs. We address this issue in Section 6.2.3 below.

We approve the portion of PG&E's forecast for MWC 11 relating to Kilarc-Cow Physical Decommissioning, UNFFR and McCloud-Pit License Conditions. Once FERC and the other regulating agencies approve the decommissioning plan for Kilarc-Cow, PG&E is required to carry out the plan on the schedule in the surrender order. Decommissioning must be done on the schedule that FERC issues. We thus accept PG&E's forecast for Kilarc-Cow decommissioning cost. Similarly, the UNFFR and the McCloud-Pit license conditions both must be carried out as soon as FERC issues new licenses. PG&E will be subject to notices of violations and fines if these pending license conditions are not implemented as ordered by FERC. Thus we accept PG&E's forecast for these items.

6.2.2.8. MWC 12 (Implement Environmental Projects)

PG&E forecasts $8.32 million primarily to cover oil spill prevention projects. DRA recommends no funding for five minor oil spill prevention projects (under $1 million) resulting in a 16% reduction of $1.3 million in the 2014 forecast based on its cash flow methodology.

Discussion

We adopt PG&E's forecast for MWC 12, and decline to adopt DRA's recommended funding reductions. Such reduced funding would increase the

risk of an oil spill into California waterways. The Oil Spill Prevention Projects (OSPP) work is intended to keep oil from polluting waters and ground adjacent to and downstream of PG&E's hydro facilities. Adopting DRA's funding proposal would limit PG&E's investment in OSPP work throughout the 2014 GRC cycle.

6.2.3. FERC Hydro Licensing Balancing Account

PG&E proposes to create a FERC Hydro Licensing and License Implementation two-way balancing account that would include all FERC License Renewal and major License Amendment work, plus implementation costs to comply with the pending new license conditions. PG&E seeks balancing account treatment due to "challenges with respect to determining the nature and timing of the costs of implementing new license conditions and receiving new licenses from FERC. Historically, the FREC licensing process has exceeded the targeted dates for completion by several years.

TURN proposed an alternative approach, providing for capital costs for hydro relicensing that go into service after the test year to be included in post-test year rates akin to the adders provided for in the Gas Accord process. This mechanism recognizes that project timing is uncertain, and amounts that go into rate base are relatively large and "lumpy" without supporting the utility's rush to establish yet another balancing account. TURN argues that the alternative mechanism has worked well with large projects over several Gas Accord cases and fits the hydro relicensing case well.

TURN's approach permits recovery of costs in the amount the utility actually records without first overcollecting based on forecasts already demonstrated to be incorrect.

PG&E argues that balancing accounts are familiar and thus can be easily understood and reviewed by interested parties and the Commission. PG&E claims that TURN offers no reasoned basis why its proposal should be adopted over PG&E's balancing account proposal.

Discussion

We conclude that a separate recovery mechanism is warranted to address the forecasting uncertainty associated with FERC Hydro Licensing and License Implementation. We approve PG&E's proposal to implement a two-way balancing account for this purpose. Although DRA opposes PG&E's balancing account proposal, DRA offers no persuasive reasons to deny the proposal. We conclude that there is significant uncertainty in predicting when FERC will act on issuance of licenses. Since the balancing account will track both over and undercollections of revenue based on our adopted forecast, both ratepayers and shareholders will be made whole for any forecasting variances over time. We conclude that the two-way balancing account is administratively simpler than TURN's proposal, and over time, will accomplish an essentially similar result, making both ratepayers and shareholders whole for any forecasting variances.

6.3. Nuclear Operations

PG&E's DCPP is a 2,240-MW facility located 7.5 miles north of Avila Beach in San Luis Obispo County, California. The site consists of approximately 12,000 acres of PG&E-owned land and the assets related to two nuclear units, including a power block and related facilities. PG&E's primary responsibility as the owner and operator of DCPP is to generate power safely and reliably through cost-efficient management of plant and related assets. As a preliminary observation, in addressing PG&E's nuclear operations costs, we take general note that various degrees of uncertainty exist concerning future measures that may be

imposed by other regulatory agencies to address, in particular, DCPP seismic risk and one-through cooling requirements that may ultimately impact future operation of DCPP. In particular, PG&E has an ongoing commitment in connection with the operating licenses for DCPP issued by the Nuclear Regulatory Commission (NRC) to fund and implement a Long Term Seismic Program (LTSP) to continuously study and update the state of knowledge regarding seismic hazards affecting DCPP. The LTSP ensures that seismic hazards are continuously assessed by PG&E and the NRC and ensures the safe operation of Diablo Canyon. PG&E was expected to submit a draft report containing the most recent results of its seismic surveys to the NRC by mid-summer 2014. Depending on the outcome of these seismic studies, there could be potential long-term seismic vulnerabilities for DCPP that would need to be addressed.

We make no ratemaking adjustments to reflect these uncertainties regarding DCPP seismic studies at this time. In general recognition of such uncertainties, however, we affirm that the Commission retains discretion to exercise its options as may be deemed necessary to protect ratepayers from unreasonable costs if the plant was to no longer be operational.

6.3.1. Nuclear Operations Expense Overview

PG&E forecasts $415.5 million for Nuclear Operations expenses for 2014, an increase of $101.293 million or 32.24% over 2011 recorded adjusted expenses. PG&E's Nuclear Operations are for the DCPP consisting of two nuclear PWR units and steam-electric turbine generators, feed water and cooling water systems, and related facilities. PG&E developed its forecasts based on 2011

recorded costs, one-time adjustments to these costs, and estimated additional costs for proposed projects and continued funding for an aging workforce.

Key differences among PG&E, DRA, and TURN with respect to the 2014 forecasts for Nuclear Operations expense are set forth in Table 6-16 of PG&E's opening brief. DRA recommends an overall reduction of $92.3 million to PG&E's forecast, for a 22.3% reduction. DRA bases its 2014 forecast on a three-year historic average (2010-2012). DRA claims that historical embedded funding resulting from employee retirements and overtime costs can be reallocated and utilized for 2014 Test Year activities. PG&E claims that DRA fails to apply an inflation adjustment, overlooks spending trends in 2012 and 2013, and ignores new projects and Nuclear Regulatory Commission (NRC) and business requirements applicable to 2014. PG&E also claims DRA incorrectly accounts for the two refueling outages that will be required for 2014.

TURN starts with PG&E's 2014 forecast amount and recommends reductions in seven areas for an overall reduction of $46.1 million to PG&E's Nuclear Operations expense forecast, a reduction of 11.2%. TURN proposes reductions of: (1) $16.3 million in project work (based upon a five-year average); (2) $9.4 million in new staffing; (3) $6.9 million in non-outage overtime; (4) $2 million for reduced write-off of obsolete inventory; (5) $1.8 million of NRC and Nuclear Energy Institute (NEI) fees; (6) $0.4 million of IT application support; and (7) $9.6 million due to a different approach for the second refueling outage.

The Alliance For Nuclear Responsibility (A4NR) contests approximately $1 million relating to Senior Seismic Hazard Analysis Committee (SSHAC) funding, and presents other proposals as discussed in Section 6.3.1.14 below.

6.3.1.1. Nuclear Refueling Outage Costs (MWC AB)

PG&E typically conducts one nuclear refueling outage each year at Diablo Canyon. In 2014, however, PG&E forecasts that Diablo Canyon will have two refueling outages. The need to balance the optimization of a fuel cycle with the desire to avoid shutdowns during the high-demand summer months results in a two-outage year approximately once every five years.

Three issues are in dispute regarding the dual refueling outages at DCPP in 2014: (a) the reasonableness of PG&E's forecast cost for the outages; (b) ratemaking treatment for cost recovery of the second outage; and (c) whether PG&E's forecast for Steam Generator (SG) inspections is reasonable and whether it should be normalized over the three-year rate cycle.

PG&E expects to incur $97.5 million in 2014 covering the first and second refueling outages at DCPP. The combined cost of these outages excluding expense projects is $97.5 million. With expense projects included, PG&E's total forecast is $107 million. To smooth out the impacts over the GRC cycle, PG&E proposes to normalize the cost of the second outage in 2014 by including one-third of the total costs in 2014 and in the 2015-2016 attrition years, equal to $18.7 million annually. PG&E's approach reduces 2014 forecast expense by $37.4 million and credits rate base with a prepayment of $18.7 million (reducing revenue requirements by about $2.2 million) for the second outage occurring in 2014. PG&E includes the $37.4 million reduction in 2014 expense, as a credit in MWC AB, associated with PG&E's proposal to amortize the second refueling outage at DCPP over three years.

PG&E thus forecasts a credit of $37.4 million to 2014 Nuclear O&M expense in MWC AB to normalize the $56.1 million cost of the second DCPP refueling outage across the GRC cycle. This results in a yearly cost to customers

of $18.7 million per year for the three-year period. By forecasting the $18.7 million yearly cost and removing the $56.1 million total cost of the second refueling outage from 2014, the test year expense forecast is reduced by $37.4 million (=$56.1 million-$18.7 million).

DRA disputes PG&E's nuclear refueling outage forecast and recommends a 2014 forecast of $0.0 million, which is PG&E's 2011 recorded adjusted amount for MWC AB. DRA claims that the average recorded data that it utilized included costs for two refueling outages.

PG&E claims that DRA used a selective approach to its averaging technique, and only appropriately included the second refueling outage year in its calculation for certain MWCs, which comprise only about 15% of DRA's total recommendation. PG&E claims that DRA's selective averaging technique for certain MWCs did not include 2009, thereby omitting costs for a second outage. DRA used a five-year averaging technique for MWCs BQ and BS. PG&E claims that a three-year period would have correctly averaged in the second refueling outage.

TURN recommends a forecast of $47.376 million (including projects) for each refueling outage, as compared to PG&E's forecast of $51 million for the first refueling outage and $56 million for the second outage, including projects. TURN's forecast is based on use of average recorded costs for the last three refueling outages (2010, 2011 and 2012) and omitting the below-average outage cost recorded in 2009. TURN assumes that the work for the 2014 outages is the same as its sample years.

TURN's proposes that the total cost of the second outage be included in the 2014 revenue requirement, and removed for the 2015 and 2016 attrition years. TURN's approach would set a single cost per outage, place one outage into base

rates, and allow PG&E to collect an additional outage cost in any year where two outages actually occur. This approach would offer flexibility in the event that outages do not occur on the timeline originally forecasted.

PG&E would be permitted to collect for two outages in 2014. In 2015 and 2016, the second outage cost would not be included in base rates. In the next GRC, PG&E would be able to collect the second outage cost in whatever year that outage occurs.

Under TURN's proposal, PG&E would not realize a credit for prepayments (as would occur under PG&E's normalized approach) because the second outage cost would be recovered in the same year. The cost of the second outage would not be included in the base revenue requirements for attrition in 2015 and 2016. TURN argues that these two benefits reduce ratepayer costs that are completely avoidable.

TURN argues that an average of the last three outages should be used to forecast the 2014 outage. PG&E claims, however, that these historic costs are not reflective of the scope of work planned for the 2014 refueling outages.

TURN also disputes PG&E's proposed ratemaking treatment for recovery of the $5.5 million that PG&E forecasts for steam generator inspection and repair costs to be incurred in 2014. Because these costs will not recur in any other refueling outage over the GRC cycle, TURN believes recovery for the 2014 Unit 1 outage should be normalized over the entire rate case cycle rather than being built into base outage costs.

TURN also claims that PG&E's forecasts of steam generator inspection costs apply an unsupported and undocumented 6% annual escalation rate to

2010 recorded costs for similar work. PG&E's forecast is based on applying a 6% annual escalation rate to the 2010 recorded costs for similar work.[63] TURN claims that this represents improper double-escalation and PG&E has failed to justify this non-standard approach.[64]

Discussion

We conclude that PG&E's total forecast of combined cost of these two fueling outages is reasonable, except for reductions to normalize one-time steam generator inspection costs over the three-year GRC cycle and to adjust for the 6% escalation rate, as proposed by TURN. PG&E included steam generator inspection costs of $5.5 million as a separate line item for 2014 to remain in base rates over the entire rate case cycle. Since the incremental steam generator inspection outage costs will be incurred only in 2014, but not in 2015 and 2016, we accept TURN's proposal that the one-year amount for these steam generator inspection costs be normalized over the three-year GRC cycle. In this manner, the full amount will not be collected in every year. We shall adjust PG&E's forecast accordingly, by normalizing the single steam generator outage expenditure over the entire three year cycle thus ensuring that the full costs are not collected more than once.

We also agree with TURN that PG&E's 6% escalation rate results is improper double-escalation, increasing the escalation of one item of nuclear non-labor expense more rapidly than general escalation, without reducing escalation on other items that may be rising more slowly. Applying standard

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[63] TURN opening brief, pages 227-228; RT 3123; Ex. 58, page A-99.

[64] Ex. 116 (TURN, Marcus testimony), page 46.

nuclear non-labor escalation to the $4,428,000 undiscounted figure from 2010 yields $4,915,000 in 2014 nominal dollars. TURN rounds this up to $5 million for purposes of its forecast. We adopt TURN's proposed use of a standard nuclear non-labor escalation rate, and thus reduce PG&E's forecast by $0.5 million, for a net amount of $5 million. To derive the appropriate test year expense adjustment, the $5 million is divided by 3, to result in $1.667 million adopted for 2014 (instead of PG&E's $5.5 million forecast). This expense which TURN assigns to MWC AB is actually booked to MWC BV which is where the adjustment has been made.

We decline to adopt DRA's refueling outage estimate. DRA's historic averaging method does not reasonably account for the costs of a second refueling outage, understating the 2014 forecast by $10.9 million (excluding inflation). DRA utilized certain averaging periods that missed the last two-outage year of 2009. DRA partially used a five-year historical averaging method to project costs which had the effect on outage costs of normalizing over five years, instead of the three-year GRC cycle. DRA also proposes to normalize one of the outage expense projects over a three-year period, in effect, a second normalization credit incorporated into the DRA expense forecast.

Except for the reductions in test-year outage costs proposed by TURN which we have adopted, as discussed above, we otherwise decline to adopt the other aspects of TURN's refueling outage cost forecast. TURN omits the impact of additional inspections required in 2014 outages which increase outage costs. Witness Halpin testified that 2014 is unusual with respect to heavy workload due to the expanded work scope in the refueling outages. We conclude that PG&E has reasonably forecast the total cost of the two outages scheduled for 2014, except for the reductions proposed by TURN which we adopt as discussed

above. The first outage has incremental costs for: (1) the Reactor Vessel 10-year inspection, (2) the Rod Cluster Control Assembly inspection, (3) main turbine low-pressure rotor inspection costs, and (4) SG sludge lancing. All of this work is forecasted by PG&E as a $5.5 million increase over the 2011 base year. The second outage has incremental costs for the SG eddy current testing (which occurs approximately every five years). PG&E forecasts the cost of this work at $5.0 million as a component of the $56.0 million second outage.

We also adopt PG&E's proposed three-year allocation methodology for recovery of the DCPP refueling outage costs, adjusted for the reductions proposed by TURN that we adopt as discussed above. Under PG&E's approach, while PG&E incurs the costs of two outages in 2014, customers pay only for one and one-third of the costs of these outages. PG&E is compensated for prepayment of outage costs with a credit, but customers pay less in 2014 and receive the time value of money for the deferred payment obligation. PG&E's approach avoids a larger increase in 2014 followed by a decrease in 2015. TURN's recommendation to allow recovery of only one single outage at a time by contrast would result in a one-time increase in revenue requirements for 2014 for the second refueling outage, followed by a corresponding reduction in 2015, continuing into 2016.

6.3.1.2. MWC AK - Manage Environmental Operations

PG&E's 2014 forecast for MWC AK is $3.068 million. This MWC includes the costs of the environmental group that manages environmental compliance programs mandated by federal, state, and local regulations. PG&E states that the current staffing level of four employees for this MWC is expected to remain the same through 2014. DRA's forecast is $2.467 million, based on 2011 costs.

Discussion

We adopt PG&E's 2014 forecast for MWC AK. We decline to adopt DRA's reductions. DRA improperly omitted recorded costs from MWC CR – Manage Waste Disposal Transportation and MWC JK– Manage Environmental Remediation, which were included in PG&E's forecast of MWC AK. DRA did not adjust 2011 recorded costs to include labor escalation of 3.75%.

6.3.1.3. MWC BP - Manage DCPP Business

PG&E's 2014 forecast for MWC BP is with the exception of the adjustment discussed in Section 6.3.1.12. which reflects PG&E's agreement to include only 50% of the NEI fees in its GRC forecast, a reduction of $429,000. MWC BP expenses cover the day-to-day administrative operations at DCPP, including managing professional development of secretarial and clerical resources, payroll and timekeeping services, and records management and document control programs.

This MWC costs includes clerical and administrative resources, payroll, document management, and plant cafeteria. This function included 63 staff in 2011 and is forecast in 2014 to grow to 67 (adding the Chief Nuclear Officer office).

DRA's forecast for MWC BP is $5.166 million, based on 2011 recorded costs (a reduction of $10.121 million). DRA claims that PG&E provided insufficient and incomplete information to support an increase of 195.92%, or to show that current funding levels are insufficient for 2014. PG&E's 2011 recorded adjusted expenses for MWC BP of $5.166 million is $4.670 million less than PG&E's 2011 GRC Imputed amount of $9.836 million. PG&E's recorded adjusted expenses for the years 2007-2011 for MWC PB have been less than its Imputed amount each

year. DRA claims that embedded funding that can be reallocated and utilized to address activities in the Test Year.

TURN proposes that PG&E's 2014 project expense forecast be based on a normalized average of historic spending and PG&E's forecasts for the period 2011 to 2014. TURN's adjustment would reduce PG&E's expense project forecast by about $16 million.

Discussion

We adopt PG&E's 2014 forecast for MWC BP with the exception of the adjustment discussed in Section 6.3.1.12. We conclude that PG&E adequately justified the proposed increases for MWC BP. We decline to adopt DRA's reductions. By relying on 2011 spending levels, DRA improperly omitted: (1) labor escalation of 3.75% reflecting labor agreements and benefits cost escalations; (2) accounting adjustments of historical data to account for non-DCPP charges to DCPP orders; (3) incremental material write-off charges driven by obsolescence; and (4) additional staffing needs identified by PG&E.

We decline to adopt the reductions proposed by TURN. As noted by PG&E, TURN used incorrect numbers for 2012 and 2013 and excluded Fukushima project expenses and Independent Spent Fuel Storage Installation (ISFSI) expenses. PG&E's recorded costs for DCPP expense projects are: 2011 - $11.3 million; 2012 – $22.7 million and 2013 (budget) – $20.4 million.

In Table 3-4 of PG&E's rebuttal testimony (Exh. 58 (PG&E-21)), PG&E included 2013 budget information, updated subsequent to its GRC filing.[65] These

[65] See PG&E's March 29, 2013, Budget Report in Compliance with D.11-05-018, provided in its supplemental workpapers supporting Exh. PG&E-1, Section 5, dated 4/12/13.

numbers reflect approved budget levels for 2013 in effect half-way through the year as PG&E was executing these 2013 budget amounts at DCPP. We conclude that the actual 2012 spending and 2013 budget levels reasonably forecast what PG&E will spend on DCPP expense projects in 2014. PG&E's 2014 forecast for DCPP expense projects is consistent with these trends.

6.3.1.4. MWC BQ - DCPP Support Services/ Loss Prevention

PG&E's 2014 forecast for MWC BQ of $46.353 million includes the: Site Services Department, Security Operations Group, Emergency Planning Group, Fire Protection Group, Industrial Safety Department, Access Control Group and Procedure Services Section. PG&E expects to reduce the number of employees charging to this MWC from 306 to 297 through 2014, facilitated by completion of several major security projects that reduce the need for security compensatory measures as well as work process enhancements.

PG&E forecast for MWC BQ covers expenses to: (1) maintain DCPP's security program in a high state of readiness through training programs, (2) maintain an emergency response organization to protect public health and safety and (3) provide a fire brigade and medical technician response for fire and medical emergencies. Currently, 306 employees charge time to this function. PG&E expects to reduce the number of employees by nine through 2014. PG&E claims its forecast for MWC BQ is consistent with historical trends when accounting adjustments are properly considered.

DRA's forecast for MWC BQ of $11.355 million is based on a five-year average of recorded costs (2007-2011), for a reduction of $34.998 million. DRA believes that PG&E requested more than was necessary. DRA claims that PG&E has sufficient has embedded historical funding that can be reallocated and

utilized to address PG&E's proposed activities in the Test Year. PG&E's recorded adjusted expenses for the years 2007-2010 for MWC BQ have been less than the Imputed amount each year before the change in accounting for expenses.

DRA claims that PG&E received sufficient authorized funding during 2007- 2011 and embedded historical funding can be reallocated and utilized to address proposed activities in the Test Year.

Discussion

We adopt PG&E's 2014 forecast for MWC BQ as reasonable. We conclude that PG&E justified the need for increased funding. We decline to adopt DRA's proposed reductions. By relying on average costs between 2007-2011, DRA omits proper recognition of test year requirements and does not account for the accounting change implemented in 2011 relating to security costs. In 2011, DCPP security costs were allocated to MCW BQ. This accounting change caused a significant increase in the year-to-year accounting fluctuations in MWC BQ. By using four years of relatively small balances for MWC BQ and one year of post-accounting change costs, DRA's forecasting method thus resulted in an unreasonably low 2014 forecast amount for MWC BQ. If DRA had used a two-year average, its forecast for MWC BQ would have been much closer to that of PG&E.

The forecasted costs for PG&E's Security Support costs included in the various MWCs are incorporated in DRA's estimates. DRA argues that PG&E should have identified and removed recorded costs for Security Support prior to calculating its forecast for 2014. PG&E claims that it had no obligation to identify and remove such costs, and couldn't anticipate in advance how DRA would use

historic averages to make its forecast. Aside from these arguments, we find PG&E's forecast of MWC BQ reasonable and adopt it.

6.3.1.5. DCPP Operating Expense (MWC BR)

PG&E forecasts $107.34 million for DCPP operating expenses in MWC BR which includes: Operations Services, Chemistry Department, and Radiation Protection. This MWC includes labor costs for licensed and non-licensed nuclear operators (non-licensed) and support staff. The staffing level of this MWC is expected to increase by 17 to approximately 300 in 2013 as part of DCPP's hire in advance of attrition program.

PG&E's 2014 expense forecast is based on staffing of 1,407 employees. PG&E most recent actual staffing level was 1,426 employees at Diablo Canyon. At the end of 2011, PG&E had 1,346 employees at the plant. To meet 2014 staffing forecasts, PG&E must reduce 19 positions from current levels.

DRA recommends a reduction of $15.4 million from PG&E's forecast for MWC BR, based on a three-year average (2010-2012) of historical costs. DRA claims that PG&E's forecast for 17 additional positions is overstated. DRA notes that although PG&E hired in advance of attrition during 2007 -2012, its expenses did not increase by 21.80%. DRA's historic averaging approach would result in no staffing changes from 2011 levels (or 1,346 positions -- a reduction of 61 positions from PG&E's 2014 forecast). TURN's 2014 forecast would fund 1,367.5 positions, 39.5 fewer than the 1,407 positions proposed by PG&E.

TURN opposes PG&E's request to add 58 new positions at DCPP and recommends a reduction in labor costs of $9.437 million. Based on 2011 vacancy data, TURN claims that PG&E was overstaffed by 25 positions and that PG&E is asking ratepayers to fund these 25 extra positions. PG&E denies TURN's claim.

PG&E used actual staffing levels at year-end 2011, assuming no existing vacancies were filled in 2011. PG&E thus denies that it overstated the staffing level starting point in 2011. To meet staffing forecasts for 2014, PG&E claims that it must already reduce 19 positions compared to year-end 2011 staffing levels.

PG&E claims that TURN ignored actual headcount additions at DCPP in 2012 and staffing increases in the 2013 budget provided in a data response to TURN. TURN argues that PG&E's actual employment in 2013 exceeds its own forecasts. TURN believes this suggests that the 2014 forecast also contains excessive positions relative to actual needs. TURN recommends a reduction in labor costs of $9.4 million, arguing that PG&E's 2011 vacancy data shows that PG&E on average is overstaffed by 25 positions and therefore PG&E is asking ratepayers to pay for 25 extra positions in the base year.

PG&E developed its 2014 forecast by starting with 2011 actual staffing levels and adding 58 additional staffing needs required to hire ahead of attrition. Through December 2012, PG&E has hired 130 net positions—with 64 in Security and hired to address new NRC security requirements.

The year-end 2011 figures cited by PG&E do not agree with the figures in PG&E's data response provided to TURN which showed 1,374 positions at year-end 2011, and 1,480 positions as of September 2013. This most recently reported actual staffing level is 54 positions below PG&E's official forecast (=1,480-1,426). TURN argues that this understaffing relative to PG&E's forecasted headcount is a good indication of the bloat in PG&E's overall request.

Discussion

We reduce PG&E's forecast for DCPP Operating Expense forecast for MWC BR by $9.437 million based on adoption of TURN's proposal. In all other respects, we find PG&E's forecast reasonable and adopt it. The reduction of

$9.437 million represents the new workers that PG&E claims it needs to add in advance of retirements.[66] We consider this amount to represent excessive test year estimates of new hires beyond what is justified for safe and reliable service.

We find support for TURN's proposed reduction based on the facts that: (1) a large portion of new staff can be covered by 2011 embedded costs of excess staffing, (2) fewer than 58 new hires are needed to "shadow" retiring workers because senior staff need less training, and (3) new staff reduce the embedded cost of temporary outage workers. In base year 2011, excluding the outage months, PG&E's vacancy data shows that was DCPP overstaffed by 25 positions on average.[67] TURN witness Marcus calculates that no increased 2014 funding for new hires at DCPP is necessary in view of the effects of these excess positions, less training needs for senior hires, and normalized effects of nuclear refueling outage work.

Although PG&E assumes a staffing level of 1,407 positions in its 2014 forecast, the forecast that PG&E provided to TURN projected 1,480 employees as of September 2013. Based on the 2013 level, PG&E was already 54 employees below its 2014 forecast. As observed by TURN, the fact that 2013 staff levels exceeded PG&E's own forecasts suggests the 2014 forecast also is excessive. We do not believe that safety will be jeopardized by reducing PG&E's requested funding when PG&E is already short 54 employees relative to its own forecasts and appear to be operating DCPP safely and reliably.

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[66] *See* Testimony of William Marcus at 33.

[67] Response to TURN DR 58-04, cited in Marcus Testimony at 31.

PG&E witness Halpin testified that at the end of 2011, there were 50 employees "in excess of what [PG&E] projected for that year or that time of year and claimed that this overstaffing was based on the need to "hire in advance" of retirements.[68] Since PG&E used "actual staffing levels at the end of 2011" as the starting point for assessing 2014 incremental staffing needs, PG&E's 2014 forecast could be even more inflated than noted in Mr. Marcus' testimony.[69]

PG&E calculates wages as if 50% of new hires are entry level but 30% are mid-level and 20% are senior-level. (TURN DR 58-06b). TURN questions the logic of assuming mid-level or senior-level staffer have to "shadow" a near-retiree for years before providing useful work. TURN believes either PG&E's pay estimate is wrong or PG&E's claim about the importance of shadowing for years at a time is wrong. While we recognize that new hires require adequate training relating to Diablo Canyon operations, we also question PG&E's claim that new senior-level hires cannot be presumed productive until two years into their employment. Even assuming this assumption were correct, PG&E does not reflect a productivity offset for 2014 once those employees are deemed productive.

We conclude that TURN's adjustment is reasonable in subtracting 25% of the increased labor cost forecast because midlevel and senior staff assumed to be hired only need training for shorter periods of time in specific conditions at Diablo Canyon rather than for all nuclear plant work. The cost of the temporary workers no longer hired during outages is also embedded in outage labor costs

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[68] 25 RT 3108-3109 (PG&E/Halpin); Ex. 269.

[69] Ex. 58 (PG&E-21, Halpin Bebuttal) at 3-14.

and should be credited against the costs of preretirement new hires. TURN witness Marcus calculated a credit for outage work of these new hires on a normalized basis (39.96% of days in outage-influenced months). The actual credit in 2014 would be greater assuming the effects of two outages.[70] In view of all of these considerations, we conclude that TURN's reduction of $9.437 million to PG&E's forecast is warranted.

We decline to adopt DRA's forecast, however, for MWC BR.

We conclude that DRA's forecast, based on a historic average, does not account for changed staffing requirements expected during 2014. DRA does not explain why 2012 staffing increases should be disregarded or why PG&E's plans for 2013 and 2014 are unjustified. DRA's forecast does not consider: the costs of the second refueling outage and outage costs generally.

6.3.1.6. Overtime Issues

TURN claims that PG&E's 2014 overtime forecast is excessive and recommends a reduction in PG&E's expense forecast of $6.9 million. TURN compared the historical rates of non-outage overtime as a percentage of total hours to the 2014 non-outage overtime levels and concluded that 2014 overtime levels were greater than in the past. Overtime levels are expected to increase in 2014. PG&E's forecast is a function of available resources and planned capital and expense work to be done in 2014. When the work demands exceed available hours, overtime is necessary.

TURN argues that any overtime in excess of historic levels should be disallowed fails to properly assess the level of planned work to be completed at

[70] Marcus Testimony at 32.

DCPP in 2014. TURN also assumes that all of the increased overtime is attributable to expense. PG&E responds that Diablo Canyon's overtime labor is modeled by comparing total work planned to total resources available without overtime. Overtime levels have limited impact on the expense labor costs. Overtime simply represents another resource available to meet all planned work.

We find PG&E's explanations reasonable and decline to reduce PG&E's forecast for overtime requirements.

6.3.1.7. Escalation Issues

PG&E claims that DRA failed to consider escalation factors for labor, benefits, material, contract or other (fees, employee expenses, rentals, etc.) cost element groupings. PG&E argues, however, that historical costs have continued to escalate and that labor agreements will increase costs. In many cases, DRA actually de-escalated costs by virtue of the historical averaging methods employed to project the future costs.

PG&E argues that using 3% as a conservative inflation rate, DRA's 2014 expense reduction would be increased by $43.7 million. DRA's 2014 expense recommendation for Nuclear Operations would be increased to $366.5 million. This correction alone would reduce DRA's $92.7 million reduction to $49.0 million. We conclude that it is appropriate to recognize the effects of labor and non-labor escalation in the 2014 forecast. We apply appropriate escalation factors for 2014 test year purposes, as discussed in the section below on escalation issues.

6.3.1.8. DCPP Plant Asset Maintenance Expense (MWC BS)

PG&E forecasts $184.18 million for 2014 expenses in MWC BS for the Maintenance Department, which plans and performs preventive and corrective

maintenance and surveillance testing of DCPP's mechanical and electrical equipment, instrumentation and controls. PG&E expects current staffing of 354 employees to increase by 37 as a result of the aging workforce initiative. PG&E claims that its forecasts are consistent with historical trends, with accounting adjustments and the second planned outage for 2014, and when hiring ahead of attrition is reflected. PG&E's TY 2014 forecast is an increase of 66.72% over 2011 recorded adjusted expenses.

DRA estimates $42.994 million less than PG&E for DCPP maintenance expense, based on a five-year average (2007-2011) which results in $4.91 million incremental funding over 2011 levels. DRA claims that PG&E did not provide verifiable documentation to demonstrate a need for $73.7 million incremental funding or that embedded historical funding levels were insufficient to address required maintenance in 2014.

DRA claims that PG&E did not justify (a) 2014 funding of $11.5 million (or $34.5 million over three years) for the Fukushima Daiichi NRC rulemaking; $2.932 million ($8.796 million over three years) for the Re-wedge Main Generator Project; and $0.3 million ($0.9 million over three years) for the Large Motor Rewind Project. DRA proposes funding of $3.833 million for the Fukushima Daiichi NRC rulemaking (based on normalization of PG&E's incremental request); $0.977 million for the Re-wedge Main Generator Project, and $0.1 million for the Large Motor Rewind Project.

PG&E objects to DRA's proposal to amortize those three projects over a three-year period. The 2014 forecast for the three projects is $13.232 million, but DRA only includes one-third of the cost of these projects in TY 2014 -- $4.4 million. PG&E claims that these projects are ongoing and/or too small to be amortized.

DRA proposes no incremental funding for concrete repair projects which DRA claims are for normal, routine, or on-going repair that are the same or similar to those forecast for 2014.

TURN proposes that DCPP project expenses in MWC BS and BR be normalized by averaging 2011 recorded and 2012-2014 forecasts for a test year amount of $11.039 million (a reduction of $16.31 million). TURN proposes this approach as a way to address PG&E's pattern of forecasting large test year increases that fail to materialize. TURN claims PG&E has provided no evidence that its large increase forecasted for 2014 will persist throughout the rest of the rate case cycle.

Discussion

We adopt PG&E's forecast for MWC BS. We decline to adopt DRA's reductions to MWC BS. DRA's forecast does not properly consider the costs of the second refueling outage and outage costs generally, does not consider the change in accounting for security and facility costs; and excludes labor escalation. We decline to adopt DRA's proposal to amortize three projects over three years. Amortization is not appropriate where the projects are ongoing and/or where project amounts are relatively small. We include their full costs for 2014.

In reference to MWC BS, DRA proposes to eliminate $24.8 million associated with non-outage expense projects. DRA claims these are deferred projects from the 2011 rate case covered by embedded funding.

Although GRC funding for 2011 non-outage expense projects was $11.4 million, DRA includes no funding for these on-going expense projects. DRA presumably supports funding for these non-outage expense projects at

amounts equivalent to 2011 funding. DRA also claims that certain non-outage expense projects are deferred from the prior rate case.

PG&E explains that most of the programs cited by DRA as deferred are projects that were active in 2011 and continue today. Some of the projects DRA identified as deferred did not exist in 2011 and were not funded in the last GRC.

PG&E acknowledges that certain one-time projects included in its 2014 forecast were also included in the 2011 forecast. PG&E provided a listing of these projects in its testimony.[71] PG&E explains, however, that only so much work can be done during a 45-day refueling outage. To the extent higher-priority work is identified, the outage work may be reprioritized to complete the higher priority tasks. Unplanned, higher-priority work took the place of the funds originally forecast for the postponed projects. The lower-priority projects get deferred to a subsequent refueling outage where such deferral does not impact reliability. PG&E denies that embedded funding is left over for projects that were deferred.

For projects that have continued since 2011, PG&E assessed whether 2011 funding levels were deemed adequate and asked for additional funds where there were changes in work scope for 2014. Given these constraints involved in completing work during the refueling outage, we find PG&E's explanation reasonable. We decline to eliminate the $24.8 million for 2014 non-outage expense projects.

PG&E's 2014 expense forecast in MWC BS and BR includes $21.1 million, with $9.5 million related to outage projects and $11.6 million related to

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[71] Exh. 24 (PG&E-6) at 3-25, lines 25-34; *id*. at 3-57, line 22 to 3-58, line 23.

non-outage projects. Non-outage expense projects are continuous in nature (as opposed to one-time, non-recurring). PG&E expects 2014 project expense to continue in 2015 and 2016. Expense projects are included primarily in MWC BS and MWC BR.

We decline to adopt TURN's normalization proposal for DCPP expense projects. As PG&E notes, TURN used the wrong numbers for 2012 and 2013 in its formulating its proposal and excluded Fukushima project expenses and ISFSI expenses. PG&E's recorded costs for DCPP expense projects are: 2011 – $11.3 million; 2012 – $22.7 million and 2013 (budget) – $20.4 million. PG&E's 2014 forecast for expense projects are generally consistent with these recent cost trends.

6.3.1.9. DCPP Personnel Performance Enhancement (MWC BT)

PG&E forecasts $23.536 million for 2014 for Personnel Performance Enhancement expenses, an increase of $7.4 million over 2011 levels. The MWC BT forecast includes expenses to manage employee training and training facilities. PG&E expects the People Performance staffing level to increase from 106 to 112 as a result of the aging workforce initiative.

DRA proposes maintaining funding for this activity at 2011 levels, for a forecast of $16.131 million. DRA claims that PG&E provided no verifiable documentation to show that 2011 levels were insufficient to fund 2014 activities. DRA notes that 2012 recorded expenses of $15.975 million are $3.374 million less than PG&E's own 2012 forecast. DRA's forecast provides funding that exceeds the five-year and three-year averages.

Discussion

We adopt PG&E's 2014 forecast of $23.536 million for Personnel Performance Enhancement expenses. We find PG&E's rationale for increasing its 2014 forecast over recorded 2011 spending to be reasonable. PG&E's forecast is consistent with historical trends when accounting adjustments are properly considered, when the second outage for 2014 is considered, and when incremental NRC fees for Fukushima are properly reflected.

6.3.1.10. Maintain DCPP Plant Configuration (MWC BV)

PG&E forecasts $70.238 million in 2014 for Engineering Department costs recorded in MWC BV. Engineering Department costs included in this MWC consist of: Design Engineering; System Engineering; Component Engineering; Reactor Engineering; In-Service Testing and Inspection; Reliability Engineering (which includes predictive and preventive maintenance); and Fire Protection Engineering. Currently, 230 people work or charge significant time to this MWC. The staffing level of this MWC is expected to increase by six employees by 2014 as a result of the aging workforce initiative.

DRA's 2014 forecast for MWC BV is $52.751 million, a reduction of $17.487 million. DRA bases its forecast on a three-year (2009-2011) average of recorded costs. DRA claims that PG&E's request for additional funding of $22.551 million, or 47.29%, over 2011 recorded adjusted expenses of $47.678 million is not justified based on historical expense levels. DRA also asserts that the information PG&E provided to support the increases over 2011 expense levels is insufficient and incomplete.

Discussion

We find PG&E's 2014 forecast for MWC BV to be reasonable with the exception of the adjustments discussed in Sections 6.3.1.1. and 6.3.1.14.2. The

Engineering Department is responsible for maintaining the configuration of DCPP in accordance with design and licensing standards, which in turn carries significant implications for reliability and public safety. We are not persuaded by DRA's argument to reduce PG&E's funding for the Engineering Department based merely on historic data.

6.3.1.11. Maintain IT Applications and Infrastructure (MWC JV)

PG&E forecasts $2.9 million in MWC JV for 2014 Nuclear Operations IT support services. The expenses cover the non-capitalized costs to implement and deploy infrastructure systems and software applications to enhance or maintain plant performance. PG&E's forecast includes two projects aimed at replacement of obsolete systems, as well as five projects aimed at keeping the plant in line with technological advancements and evolving utility or nuclear industry best practices.

DRA recommends funding of $1.8 million for Nuclear Operations IT project expenses, representing a $1.1 million, or 38%, reduction to PG&E's 2014 request. DRA proposes to remove funding for three of PG&E's proposed projects, which would bring PG&E's funding in line with its three-year (2009-2011) average recorded costs. DRA believes that the activities included in PG&E's proposal are the same activities associated with prudent nuclear recordkeeping and should be part of the normal, routine, and on-going maintenance activities that are already funded by ratepayers.

PG&E responds to DRA's claim by providing detailed descriptions as to how the three contested IT projects do not constitute on-going activities related to routine recordkeeping. PG&E also states that DRA's proposal to base its 2014

expense forecast on 2009-2011 average recorded costs by removing expenses for the three proposed projects is unreasonable.

Discussion

We find PG&E's forecast for 2014 Nuclear Operations IT project expenses recorded in MWC JV reasonable and adopt it. We agree with PG&E that DRA's proposed denial of the three IT projects in order to bring 2014 funding in line with 2009-2011 average recorded costs, which DRA claims is a reasonable estimate based on historical expense levels, is arbitrary, given that the projects proposed by PG&E are not part of routine maintenance activities already funded by ratepayers.

6.3.1.12. Obsolete inventory Write-off

PG&E forecasts $3.033 million for the write-off of obsolete inventory in the test year and assumes the same level of write-offs in each of the attrition years, for a total of $9.099 million over the GRC cycle. Although obsolescence of material inventory is an infrequent and irregular expense, PG&E argues that significant capital expenditures over the past three years require it to review and analyze the material inventory to ensure that obsolete material is appropriately disposed of and accounted for in Nuclear Operation's books of record.

DRA recommends no funding for obsolete inventory write-off. TURN supports DRA's forecast of zero, but offers the alternative recommendation of relying on the 2007-2012 six-year average of $1.016 million if the Commission declines to accept DRA's proposal. This marks the second rate case where PG&E has forecasted approximately $3 million in obsolete inventory during the test year. TURN argues that PG&E's forecast was wrong before and is likely wrong now. TURN thus proposes a reduction of $2.017 million from PG&E's request based on a six-year historical average. TURN argues that PG&E has not forecast

ongoing capital expenditures that justify annual write-offs of this amount throughout the entire GRC cycle.

In 2010, write-offs were $3.3 million. PG&E did not record write-offs greater than $1.2 million in any other year between 2007-2012 and had an average write-off (including 2010) of $1.016 million. The write-off in 2010 of $3.3 million was driven by the $900 in capital additions completed in that year. TURN argues that PG&E has not identified any similar massive capital projects during the test year that should result in similar levels of write-offs.

Discussion

We reduce PG&E's forecast of obsolete inventory write-offs by $2.017 million based on the recommendations of TURN. Given the relatively small amounts that PG&E has written off since 2007, we conclude that PG&E has not adequately justified the higher level of $3.033 million that it forecasts for the test year. We also conclude that DRA's proposal has not been justified to reflect an estimate of zero. PG&E has historically incurred positive levels of write-offs. We conclude that TURN's forecast of $1.016 million, based on a six-year average, offers a reasonable balance, and reflects the most representative range of historic inventory write-off levels over time.

PG&E wrote off $3.3 million in 2010 following implementation of the SG and Reactor Vessel Head projects. Since write-off of obsolete inventory is infrequent and irregular, however, the single year of 2010 write-off levels do not reflect expected test year levels.

6.3.1.13. NRC Regulatory and Inspection Fees

PG&E forecasts $13.826 million in NRC regulatory and inspection fees in the 2014 test year. PG&E's opening brief offers a table showing historical fees and a trend line analysis as a basis for its forecast.

TURN recommends a reduction of $1.326 million relative to PG&E's forecast. PG&E claims that TURN's proposed reduction is unreasonable, arguing that NRC fees have escalated significantly over the past six years with rates over 5% per year. TURN uses a four-year average (2009-2012), which includes some historical escalation, with a slight roundup to provide limited escalation in the 2014 test year.

Discussion

We reduce PG&E's forecast of NRC regulatory and inspection fees by $1.326 million as proposed by TURN. We conclude that PG&E's trend line analysis is unduly biased by escalation during 2007-2010 that has not continued in subsequent years. Historical data relied on by PG&E show little overall escalation in NRC fees since 2009 and net reductions in 2011 and 2012 relative to the 2010. PG&E's proposed trend is based on increases between 2007 and 2010 rather than any increases in 2011 or 2012. PG&E's trend line analysis would have led to estimates exceeding actual costs in four out of the past six years.

TURN relies on a four-year average (2009-2012) with a slight roundup to provide limited escalation. TURN's methodology is more consistent with recent trends in NRC fees.

6.3.1.14. Alliance for Nuclear Responsibility (A4NR)

A4NR recommends that the Commission: (1) disallow 50% of PG&E's funding request for the SSHAC as "advocacy" expenditures; (2) engage the existing Independent Peer Review Panel (IPRP) in the SSHAC process while bolstering its ground motion control capabilities through the use of expert consultants; (3) establish a two-way balancing account for NRC rulemaking expenses; and (4) provide for recovery of expenditures for NRC Rulemaking

expenses through PG&E's annual Energy Resource Recovery Account (ERRA) compliance.

A4NR submitted additional proposals in its opening brief: (1) that the Long Term Seismic Plan (LTSP) forecast of $4.84 million (including $2.0 million for the SSHAC process, as well as the associated amounts for the two attrition years) be added to the Diablo Canyon Seismic Studies Balancing Account (DCSSBA) adopted in D.12-09-008, subject to ERRA proceeding and Tier 3 Advice Letter provisions; (2) PG&E's LTSP and SSHAC activities be subject to the same review by the Commission's Energy Division Director and IPRP as specified for other DCSSBA funded activities; and (3) that PG&E submit a plan in the next GRC to comply with recommendations of the CEC regarding the pace of transfer of spent nuclear fuel to dry casks as a condition of approving costs forecast for these activities.

During the evidentiary hearings, the Administrative Law Judge (ALJ) granted a motion filed by PG&E to strike portions of the originally submitted testimony of A4NR. In its brief, A4NR argues that although the ruling was granted to strike portions of its testimony, a sufficiently detail explanation of the reasons for the ruling was not provided. We hereby affirm the ruling of the ALJ. We conclude that the ALJ properly relied upon the reasons cited by PG&E in striking the testimony at issue. PG&E moved to strike the majority of the testimony. The ALJ left in the record the A4NR ratemaking proposal for the SSHAC costs to be incurred in 2014 to 2016. The ALJ granted PG&E's motion to strike the remaining A4NR testimony and appendices that addressed NRC substantive seismic licensing issues. The ALJ properly struck this testimony since it has no bearing on costs to be incurred at Diablo Canyon in 2014 through 2016 and involves issues which are subject to review and resolution by the NRC.

We affirm the ALJ's ruling to strike the portions of the A4NR testimony which addressed the seismic licensing basis of Diablo Canyon and challenging the prudence of the manner in which the NRC addressed and resolved the seismic licensing basis issue. Also, this Commission does not have authority to override the NRC's resolution of the seismic licensing basis of DCPP. The issue also has no bearing on PG&E's GRC funding request.

6.3.1.14.1. Proposed Disallowance of SSHAC Costs

PG&E requests $4.84 million for the LTSP, of which $2 million is for the SSHAC process. PG&E is implementing the NRC directive to re-evaluate the Diablo Canyon seismic hazard using a Level 3 SSHAC process. The current SSHAC process follows the NRC guidance governing the process and substance of a Level 3 SSHAC process.

A4NR proposes that 50% of PG&E's 2014 forecast of SSHAC costs be disallowed as advocacy costs. A4NR refers to PG&E's settlement in the 2011 GRC which provides for 50% recovery of NEI fees as a precedent for its proposed treatment here. The 50% exclusion of NEI fees was based on the position that certain NEI activities, like advertising, should be funded by shareholders rather than customers because such costs do not contribute to safe, reliable and cost-effective utility operations. PG&E claims that concern is not applicable to the LTSP and the SSHAC process which covers consultant costs associated with technical seismic studies and peer reviews, and include no lobbying, advertising or other advocacy costs.

PG&E argues that LTSP costs have always been included in the GRC and can be readily estimated based upon a defined project scope. PG&E claims its LTSP forecast of $4.84 million is reasonable, and that there is no basis for

transferring LTSP costs from the GRC to the ERRA proceeding. PG&E manages the LTSP subject to a NRC license commitment and is conducting the SSHAC process in response to NRC directives.

PG&E claims that A4NR wants to use the GRC process to condition rate recovery for nuclear operations as a means of indirectly compelling PG&E to take actions that the Commission does not have legal authority to directly order. The federal court of appeals recently held such indirect attempts by states to regulate nuclear safety issues are preempted by federal law.

Discussion

We decline to grant the request of A4NR that 50% of PG&E's 2014 forecast of LTSP costs be disallowed as advocacy costs. After its testimony was stricken, A4NR withdrew this recommendation for lack of evidentiary support.

6.3.1.14.2. Transfer of Seismic Plan Costs out of the GRC

A4NR proposes that the Commission remove $4.84 million in LTSP costs from this GRC and transfer the costs to the Diablo Canyon Seismic Studies Balancing Account (DCSSBA), a balancing account adopted in D.12-09-008 as a ratemaking mechanism for seismic studies funded by that decision. A4NR believes that LTSP costs should be treated differently from other Diablo Canyon-related expenses in the GRC forecast. A4NR disagrees with aspects of how PG&E is managing the SSHAC process and therefore asks the Commission to review PG&E's on-going management of the SSHAC process and the LTSP generally in the ERRA compliance proceeding.

PG&E opposes this proposal, arguing there is no basis to conclude that it has unreasonably administered the SSHAC process by conducting a Level 3 analysis rather than the Level 4. The NRC has issued guidance that a Level 3

analysis should be used. PG&E argues that this Commission has no basis, expertise or jurisdiction to overrule that definitive determination of reasonableness. PG&E argues that A4NR is apparently proposing an indirect way of regulating NRC regulatory matters which is impermissible under the law.

Discussion

We adopt the proposal of A4NR to remove $4.84 million in LTSP costs from the 2014 revenue requirement for purposes of this GRC and to transfer the LTSP costs to the DCSSBA, a balancing account adopted in D.12-09-008. As proposed by A4NR, the LTSP costs shall be subject to the same annual ERRA Compliance proceeding and Tier 3 Advice Letter provisions adopted for the DCSSBA in D.12-09-008. We find this disposition to be a reasonable approach to improving oversight of the LTSP costs.

While A4NR was not allowed to observe one workshop for a portion of the SSHAC being conducted jointly with operators of two other western nuclear power plants, we conclude that the PG&E-specific workshops have been adequately transparent and open. PG&E pledged to work with its joint participants to open the remaining joint workshops to public participants.

6.3.1.14.3. Additional Layer of Review of SSHAC Process

A4NR proposes that the SSHAC and LTSP activities be subjected to the "same review by the Commission's Energy Division Director and Independent Peer Review Panel." PG&E argues that the Commission should not attempt to formally interject the IPRP into the SSHAC process and doing so could disrupt progress to date and impair PG&E's ability to complete the process in time to meet the NRC's deadline.

Discussion

We adopt A4NR's proposal. We find this disposition to be a reasonable approach to assure the proper integration of Assembly Bill (AB) 1632 seismic studies with the LTSP and the SSHAC process.[72]

6.3.1.14.4. Conditions Related to the Rate of Spent Fuel Storage Into Dry Casks

A4NR proposes that conditions be placed on approval of PG&E's proposed cost recovery of $26.1 million to construct the remaining five pads at the ISFSI in 2014 and $19.6 million to transfer spent fuel to dry cask storage in 2015 and 2016. A4NR proposes that PG&E's proposal be approved only on the condition that PG&E file with its next GRC a satisfactory plan to comply with CEC recommendations regarding the transfer of spent fuel to dry cask storage in its AB 1632 Report. The specific recommendation in the AB 1632 Report was that: "PG&E and SCE should return their spent fuel pools to open racking arrangements as soon as feasible, while maintaining compliance with NRC cask and pool spent fuel storage requirements, and report to the Energy Commission on their progress in doing so." (AB 1632 Report., p. 15).

PG&E opposes this recommendation, arguing that under federal law, the CEC does not have legal authority to regulate nuclear safety issues. PG&E argues that A4NR is attempting to impermissibly use the ratemaking process to compel utility action on nuclear safety issues exclusively regulated by the NRC.

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[72] Assembly Bill (AB) 1632, codified as Public Resources Code Section 25303, directed the California Energy Commission (CEC) to assess the potential vulnerability of California's largest baseload power plants, including Diablo Canyon Power Plant, to a major disruption due to a major seismic event and other issues. In response to AB 1632, in November 2008 the CEC issued

Footnote continued on next page

Discussion

We find it reasonable to grant the proposal of A4NR to direct PG&E to file with its next GRC a satisfactory plan to comply with CEC recommendations regarding the transfer of spent fuel to dry cask storage in its AB 1632 Report, and to approve PG&E's forecast of $26.1 million to construct the remaining five pads at the ISFSI in 2014 subject to its compliance with this condition. Since we limit 2015 and 2016 revenue increases based on the attrition mechanism we approve in Section 12, A4NR's proposal is moot as it relates to 2015 and 2016 costs.

6.3.2. Nuclear Department Capital Costs

PG&E forecasts $254.55 million for 2014 capital costs for Diablo Canyon. DRA recommends a 14% reduction in the 2013 and 2014 forecast for IT Projects in MWC 2F. Otherwise, DRA reviewed the projects in PG&E's capital forecast for Diablo Canyon and found them reasonable.

TURN proposes a $3.282 million reduction to PG&E's MWC 20 capital forecast of $240.848 million relating to: (1) the Transformer Supercooler Replacement Project, and (2) the DCPP Access Road Repairs project. PG&E initially contemplated that there would be expense dollars associated with these projects in the 2011 GRC forecast. Because of the changed nature of the situation, when the work was actually done, they were accounted for as capital projects.

6.3.2.1. Nuclear Operations IT Projects (MWC 2F)

PG&E forecasts $4.1 million in 2013 and $11.2 million in 2014 for IT costs to support Nuclear Operations in MWC 2F. PG&E's forecast includes costs for:

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its findings and recommendations in its AB 1632 Report, which was part of its 2008 Integrated

Footnote continued on next page

(1) systems that, having reached the end of their useful life or having become technologically obsolete or unsupportable, must be replaced to continue providing existing functionality or to maintain or improve plant safety; (2) systems that need to be replaced or upgraded to comply with the NRC's Enhancements to Emergency Preparedness Regulations; and (3) projects that keep the plant in line with technological advancements and evolving industry best practices.

DRA proposes $3.5 million in 2013 and $9.6 million in 2014 for Nuclear Operations IT costs, representing a 14% reduction due to PG&E's use of the Concept Cost Estimating Tool to develop its forecasts.

Discussion

We approve PG&E's 2013 and 2014 forecasted Nuclear Operations IT budget under MWC 2F, except for a 14% adjustment to PG&E's forecasts based on DRA's proposed reductions. DRA recommends a 14% reduction to forecasts calculated by the Concept Cost Estimating Tool due to its analysis that PG&E spent 86% of the budgets that were approved in the 2011 GRC for project forecasts that were developed using the Concept Cost Estimating Tool. Consistent with adoptions elsewhere in this Decision, we find DRA's argument to be reasonable and accordingly reduce PG&E's 2013 and 2014 forecasts by 14%.

6.3.2.2. Transformer Supercooler Replacement

The Transformer Supercooler Replacement project was incorporated as a maintenance expense item in PG&E's 2011 GRC adopted revenue requirements. PG&E subsequently determined, however, that the Transformer condition had

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degraded and needed to be replaced. Instead of implementing maintenance as originally contemplated, PG&E instead completed the replacement, capitalized at $3.9 million. Consequently, PG&E did not account for the transaction as maintenance expense, as originally contemplated. Based on these facts, TURN argues that PG&E has already recovered the cost of this project via the expense component of the 2011 revenue requirements.

TURN claims that since the Transformer Supercooler Project ($3.9 million) was forecast as expense in the last rate case, the capitalized project should be removed from rate base. TURN argues that PG&E should not be allowed to engage in after-the-fact reclassification of this project as capital. If PG&E had identified its intent to capitalize this project in the 2011 GRC, the authorized O&M revenue requirement would have been adjusted downward. TURN argues that if allowed to reclassify expense projects, PG&E would circumvent revenue requirement limitations and effectively get a second bite at the apple.

TURN thus argues that PG&E is seeking double recovery by including the capitalized $3.9 million replacement in the 2014 GRC revenue requirement. PG&E denies, however, that there is double recovery. PG&E explains that it never implemented the project as an expense item. PG&E asserts that the revenues collected as expense relating to this project were reallocated to pay for other unfunded projects needed to improve performance. PG&E asserts that it will have spent at Diablo Canyon approximately 99% of the imputed expense budget for Diablo Canyon during the period 2011-2013.

Discussion

We agree with TURN that the $3.9 million for the capitalized Transformer Supercooler Replacement should be excluded from the 2014 revenue requirement. While adopting TURN's proposed reduction, we do not question

the merits of PG&E's operational decision to replace rather than repair the Supercooler Transformer. Likewise, we believe PG&E followed applicable accounting procedures in capitalizing the replacement cost of the Transformer Supercooler. Since PG&E never recorded actual expenses for maintenance on the Transformer Supercooler, PG&E's forecast 2014 expense does not include embedded expense relating to maintenance of the Transformer Supercooler. Nonetheless, despite these facts, we agree with TURN that ratepayers have previously funded revenues during the 2011-13 GRC cycle that included a provision for maintenance expense for the Transformer Supercooler. This fact is not refuted by PG&E's claim that it spent those funds on other projects. PG&E's choice to spend money on other unfunded projects should be based on its duty to provide safe and reliable service, not on the fortuitous availability of extra funding from an unanticipated change in the accounting of a transaction. PG&E's level of and obligation for spending on unfunded projects is independent of the fact that ratepayers have already funded a provision in rates for the costs of the Transformer Supercooler. PG&E has thereby already recovered revenues for an expense that it did not incur. Consequently, we conclude that ratepayers should not be required to fund a capital replacement that substituted for maintenance that ratepayers previously funded but which never occurred.

6.3.2.3. Diablo Canyon Access Road

TURN proposes that PG&E's capital spending forecast for 2014 be reduced by $3.28 million associated with repaving the seven-mile Diablo Canyon access road. This capital project started in 2011, and PG&E expects it to continue through 2014.

The last GRC included both a capital forecast (for access road replacement) and an expense forecast (for access road repairs). In the last GRC, PG&E requested $4 million expense for road repair and $25 million in capital for road repaving at Diablo Canyon. Although the $4 million in expenses were included in PG&E's 2011 test year revenue requirements, no expenses were incurred for the project. PG&E did spend $1.36 million in capital during 2011-2012 and plans to spend $3.28 million in capital during 2014.

TURN argues that because the $4 million in repairs forecast for 2011 were never spent, there should be a $4 million reduction in expense to account for this. TURN also argues that a $3.3 million project to repair the Diablo Canyon access road should be deferred and PG&E should only do this work if DCPP's NRC operating license is extended. TURN proposes that, at a minimum, removal of the $4 million for expenses included in the 2011 forecast and embedded in the 2014 forecast as base costs. In addition, TURN argues that PG&E should not be permitted to add new expenses for this project in the 2014 test year. Furthermore, TURN proposes that the Commission remove the $3.282 million from 2014 capital spending to compensate ratepayers for the expense work that was funded but not performed in 2011-2013.

PG&E did proceed with the access road capital project in 2011 and this replacement project will continue through 2014. PG&E claims that it acted prudently in not spending $4 million to repair a road that will be replaced. The 2011 GRC forecast included $4 million in expense associated with repairs of the access road but the expense portion of the project was cancelled and reclassified as a capital project which commenced in 2011. PG&E used the $4 million that had been collected as expense funding for the access road to pay for other high priority expense work at Diablo Canyon.

TURN questions whether major new road investments are warranted given the significant possibility that Diablo Canyon will only operate for another eight years until its license expires. TURN argues that cheaper options should be considered including expense work that would accomplish sufficient road improvements to last through the end of the current license.

PG&E responds that waiting for certainty on the license renewal status doesn't make sense with regard to the access road, as the road will be needed for many years after its completion regardless of the outcome of license renewal. The access road will be used for at least 25 more years (11 years for operations and many more for decommissioning and spent fuel storage) even if license renewal does not proceed.

PG&E claims that the entire 7-mile long access road remains in need of repaving. If it is not replaced soon, the road will have to be maintained by ever increasing and more costly repair efforts, until it can be repaved.

TURN proposes to reduce PG&E's 2014 forecast of capital expenditures for two projects totaling $3.3 million.

TURN argues that whether PG&E spent the money on something else is of no consequence, but that PG&E should not be allowed to manipulate the GRC process by reclassifying a project from expense to capital after the fact. TURN claims that opening the door to this type of behavior will encourage abuses, complicate the process of monitoring compliance with past decisions and make it challenging to determine what is being prospectively authorized in a particular GRC.

PG&E argues that there was no windfall, but that any expense dollars not spent as a result of the reclassification of the Transformer Supercooler project or

the decision not to repair an access road that will be replaced were reallocated to other uses at DCPP.

Discussion

We reduce PG&E's capital forecast for 2014 by $3.28 million associated with repaving the seven-mile Diablo Canyon access road. Based on similar considerations as discussed in reference to our disposition of the Transformer Supercooler, we conclude that ratepayers should not be charged again for the costs of a project that was already included in prior rates.

6.3.3. Nuclear Regulatory Balancing Account

PG&E proposes a two-way balancing account for "new nuclear safety and security regulatory-mandated projects" totaling an estimated $204 million (expense and capital) during the GRC period. The two-way balancing account is proposed for the NRC rulemaking associated with Fukushima Daiichi Nuclear Station costs of $11.500 million, Cybersecurity of $1.608 million and Emergency Planning of $1.452 million. PG&E states it is difficult to estimate the cost and timing of the new NRC rules, and that it has never before faced the broad spectrum and magnitude of recent changes and additions to NRC regulatory requirements. Rulemakings and imposed deadlines in the areas of Station Security, Emergency Planning and Response, Post-Fukushima analysis and modifications, and Station Fire Protection have already cost more than $100 million to date.

DRA accepts PG&E's capital forecasts for $169 million in regulatory projects but opposes balancing account treatment for them. DRA asserts that uncertainty of NRC actions has not materialized and absent an actual problem, there is no justification for a balancing account. DRA argues that PG&E has managed to balance safety, reliability, uncertainty, and rate recovery without

previously reported problems. DRA suggests that if and when there becomes a particular problem, PG&E can make a request through special application.

Discussion

We adopt PG&E's proposal to establish a two-way balancing account for costs associated with NRC rulemakings for the Fukushima Daiichi Nuclear Station costs of $11.500 million, Cybersecurity of $1.608 million and Emergency Planning of $1.452 million. We agree with PG&E that the uncertainties associated with the effects of these NRC rules make it difficult to develop accurate forecasts. The future costs in these categories will be unclear until the NRC rulemakings are complete, plant- specific requirements are clarified, and the implementing projects are scoped and estimated. The balancing account will provide a vehicle to cover PG&E's reasonably - incurred costs while ensuring that ratepayers do not pay for forecast costs that are not incurred associated with these activities.

6.4. Fossil and Other Generation Operations

6.4.1. Fossil and Other Generation Expense Overview

PG&E forecasts $54.366 million for Fossil and Other Generation Operations expenses for Test Year 2014, an increase of $8.6 million or 19% over 2011 expenses of $45.786 million. PG&E's Fossil and Other Generation Operations facilities include Gateway, Humboldt Bay, and Colusa Generating facilities, seven ground-mounted Photovoltaic solar stations, and fuel cell generating facilities. Eighty-three percent of the expense increases are driven by increased work in MWCs KK and KL. PG&E's forecast utilizes 2011 recorded costs and expense forecasts to develop the revenue requirements adopted in D.10-04-052, and D.10-04-028 plus incremental expenses for proposed projects.

The DRA estimate for PG&E's Fossil and Other Generation Operations expenses is $46.606 million, which is $7.76 million less than PG&E's forecast.

6.4.1.1. Operate Fossil Generation (MWC KK)

PG&E's 2014 expense forecast for MWC KK is $14.591 million for planning and performing routine operations at PG&E's fossil facilities, including engineering and clerical support. The forecast is primarily for labor costs at Humboldt, Colusa and Gateway. To develop the forecast, PG&E: (1) started with 2011 recorded costs; (2) subtracted 2011 nonrecurring costs; (3) added labor and non-labor escalation; (4) added costs reassigned to MWC KK due to accounting changes; and (5) added 2014 costs related to new work scope, including two new power plant technicians at Humboldt and implementation of a document storage program at the fossil facilities.

DRA's forecast for MWC KK is $12.935 million, based on an average of 2011 and 2012 costs with no escalation. DRA asserts that costs for two new technicians should be excluded from PG&E's forecast and absorbed by embedded 2011 authorized revenues, citing the savings in overtime as an example of 2011 costs that would offset the new employee costs. DRA asserts that the costs of the new employees are overstated because PG&E's forecast includes certain costs, such as materials, tools and vehicles, that should be included in A&G expenses. TURN points out that PG&E failed to reflect reduced overtime costs at Humboldt that would result if the two new employees are hired. TURN argues that the reduced overtime should fully offset the cost of the two new employees. PG&E acknowledges that some reduction in its forecast is appropriate for the savings in overtime, but claims that TURN overstates the amount of adjustment. PG&E agreed to deduct $267,000 in reduced overtime

from its 2014 forecast to addresses DRA's and TURN's concerns. PG&E argues that its approach is a more reasonable and accurate method of adjusting for the reduction in overtime, as compared to DRA's and TURN's proposals.

DRA and TURN also oppose additional ratepayer funding for the fossil generation document storage program. PG&E included $240,000 in its 2014 forecast to transfer existing fossil documentation to the new corporate Documentum platform. The program will provide attributes to all fossil as-built drawings (currently in electronic form) and incorporate these attributes into Documentum. The program improves the ability to retrieve documentation, confirm its accuracy, and improve document management systems and operations. DRA argues that since the fossil plants are new, the current document management systems should be sufficient and that current authorized funding levels should be adequate to fund any improvements that are necessary. The fossil plants already store documents in electronic format at individual share point servers at the plant locations.

Discussion

We adopt PG&E's 2014 forecast for MWC KK of $14.591 million, and decline to adopt DRA's and TURN's proposed reductions. DRA's proposed use of 2011-12 averages with no escalation does not provide adequate funding for the scope of test year activities. We accept PG&E's adjustment of $267,000 for overtime as appropriate resolution of disputes over funding for two new technicians at Humboldt. We also accept PG&E's forecast of $240,000 to transfer fossil documentation to the new corporate Documentum platform to improve records management. This project will add key attribute data into the Documentum system, which will enhance the ability to retrieve the data and search for specific attributes. Understanding the accuracy of the fossil plant

documentation and improving data retrieval will enhance the safety aspects of the work at PG&E's fossil plants.

We conclude that PG&E's $240,000 cost of migrating existing data for the fossil plants and adding attribute data is reasonable in relation to the expected safety and operational efficiency benefits.

6.4.1.2. Maintain Fossil Generating Equipment (MWC KL)

PG&E's forecast for MWC KL is $31.9 million for maintenance at Gateway, Colusa and Humboldt, including labor to maintain the facilities, the Long-Term Service Agreements (LTSA) at Colusa and Gateway, materials and contracts for the facilities and other maintenance and engineering services.

DRA forecasts $27.045 million based on 2011 recorded costs, for a reduction of $4.897 million. DRA argues that the embedded 2011 funding for this MWC should be adequate to address work activity for 2014.

PG&E opposes DRA's use of 2011 recorded costs, pointing out an average of 2011 and 2012 recorded costs (as DRA used for MWC KK) would have yielded a forecast $1.7 million higher than DRA's 2014 forecast.

DRA cites the piping integrity program ($722,000) and machinery assessment program ($386,000) as examples of work that should be removed from the 2014 forecast because it is or should be covered by the LTSAs for the facilities. PG&E responds that there is no LTSA for Humboldt and these two programs are not covered by other LTSAs. PG&E explains that the piping integrity program addresses balance of plant piping systems, such as the low pressure steam, boiler feed water and condensate steam systems. Inspections focus on the highest risk areas. The program will allow detection of problems before they grow large or catastrophic.

TURN recommends removal of $771,000 cost from PG&E's 2014 forecast for MWC KL for the material traceability program which is designed to track the location and specifications of materials used in the construction, operation, and maintenance of Gateway, Colusa and Humboldt throughout their life cycle. PG&E argues that the program will enable searches at individual plants or across the fleet to more easily find a particular piece of equipment that may have a defect or be recalled, allowing PG&E to more thoroughly and quickly address potential safety and reliability issues.

TURN recommends that Humboldt maintenance be reduced to $1.73 million, a reduction of $696,000. TURN argues that PG&E can defer major maintenance costs beyond 2016 by changing operations at Humboldt and running certain high hour Humboldt units less and low hour units more.

Discussion

We adopt PG&E's 2014 forecast for MWC KL of $31.9 million. We conclude that PG&E adequately justified its forecast. We decline to adopt DRA's or TURN's proposed reductions for MWC KL. We address specific issues raised by DRA and TURN below.

TURN recommends imputing a $90,000 credit to MWC KL to reflect savings from the Gateway auxiliary boiler replacement project, assuming savings equal to 5% of the capital project. PG&E no longer plans on replacing the auxiliary boiler during this rate case cycle. Thus, there will be no savings and it would be inappropriate to impute a $90,000 credit.

We adopt PG&E's amortization allowance for the Colusa LTSA milestone payment over a six-year period from 2014 to 2019. We decline to adopt DRA's proposal to exclude the amortization from the 2014 forecast, and address it in the next GRC since the payment does not occur until 2019. We conclude that it is

reasonable to continue the treatment started in the last GRC for Colusa to continue to amortize the cost of hot gas path inspections ratably over the six-year period of wear and tear that leads to the need to do the work.

We decline to adopt TURN's proposed reductions to maintenance costs at the Humboldt facility. TURN's proposal that PG&E defer maintenance by changing the running hours on the Humboldt units could adversely affect reliability in the North Coast region by having multiple units out for maintenance at the same time. We also decline to adopt TURN's proposal to use 2014-2016 average forecast costs for Humboldt rather than a 2014 forecast for test year purposes. We conclude that the test year forecast should be based on 2014 operations, rather than on changes expected during 2015 and 2016. We separately address ratemaking for 2015 and 2016 attrition elsewhere in this decision.

6.4.1.3. MWC KM – Maintain Fossil Buildings, Grounds, & Infrastructure

PG&E's 2014 forecast for MWC KM is $3.048 million covering maintenance at common facilities at Colusa, Gateway and Humboldt. To develop its forecast, PG&E: (1) started with 2011 recorded costs; (2) subtracted one time and infrequent work; (3) added costs that were reallocated from MWC KL as a result of accounting changes; (4) added escalation for labor and non-labor; and (5) included new work scope for corrosion protection services at Humboldt.

DRA proposes a $2.247 million forecast based upon a two-year average of 2011 and 2012 recorded costs. DRA notes that 2011 was the first full year of operations for PG&E's fossil operations.

PG&E identifies two reasons for forecasted increases in 2014 above 2011. PG&E forecasts extensive corrosion protection work at Humboldt. This

maintenance work was not required in 2011 because the new structures were adequately coated during initial construction. Now, after three years of exposure to this corrosive environment, it is necessary to recoat surfaces to prevent corrosion.

PG&E also updated 2011 recorded costs to include labor and non-labor escalation and to reflect the reallocation of certain contract maintenance-related costs from MWC KL to MWC KM. PG&E argues that DRA's forecast understates maintenance funding needs because it is based upon costs in 2011 and 2012 when the fossil plants were new.

Discussion

We adopt PG&E's forecast for MWC KM. We decline to rely on DRA's forecasting basis of 2011-2012 recorded costs which do not account for the increased scope of 2014 activities as noted in PG&E's forecast. PG&E provided reasonable explanations of increased funding needs in 2014 due to corrosion protection work and to reflect the reallocation of contract maintenance work.

6.4.1.4. MWC KQ – Operate Alternative Generation/ MWC KS – Maintain Alternative Generation Buildings, Grounds and Infrastructure

PG&E's 2014 forecast for MWC KQ is $364,000 and the forecast for MWC KS is $108,000. MWC KQ and KS address operations and maintenance expenses for PG&E's PV and fuel cell facilities. PG&E began using MWC KQ and MWC KS in late 2012 to better track the costs associated with the new PV and fuel cell facilities. Previously, fuel cell and PV operations and maintenance costs were recorded in MWC KR. PG&E's forecast for these MWCs was based upon the O&M estimates in the applications approved by the Commission for these projects, although PG&E has revised downward the forecasts originally

submitted to the Commission to reflect lower LTSA costs for operation of the fuel cells and the sharing of one PG&E employee among the facilities.

DRA proposes a forecast of $60,000 for MWC KQ and $6,000 for MWC KS, based on 2012 recorded costs for the facilities.

Discussion

We adopt PG&E's forecast for MWC KQ of $364,000 and its forecast for MWC KS of $108,000. We conclude that PG&E's forecasts are reasonable and consistent with the O&M forecasts previously approved by the Commission for the projects included therein. We decline to adopt DRA's reductions. DRA did not take into account that costs in MWC KQ and MWC KS reflected only a partial year of activity in 2012 for the fuel cell and PV facilities.

6.4.2. Fossil and Other Generation Capital Expenditures

Based upon agreements reached between the parties, there are no longer any disputed issues concerning PG&E's capital expenditures forecast for the Fossil and Other Generating Operations. We approve and adopt the following changes to PG&E's capital expenditures forecast that have been agreed upon:

(1) PG&E and DRA agreed to use 2012 actual capital expenditures rather than PG&E's 2012 forecast.

(2) PG&E and TURN agreed to reduce the forecast for the Humboldt Bay Generating Station (HBGS) GHG reduction equipment project ($500,000 per year) to zero.

(3) PG&E and TURN agreed to reduce the forecast of the HBGS warehouse to $635,000, a reduction of $1.628 million.

(4) PG&E and TURN agreed that disputed issues pertaining to the Humboldt spare generator and the Gateway/Colusa spare transformer are resolved by adoption of 2012 recorded costs for these projects.

6.4.3. Decommissioning and Fuel Oil Inventory Costs

There are no disputed issues concerning PG&E's forecasts for fossil decommissioning or the diesel fuel inventory for HBGS. We approve PG&E's forecasts for these uncontested items.

6.4.4. Fuel Cell Project Costs Above Authorized Amounts in D.10-04-028

There are no contested issues regarding PG&E's request to increase its cost recovery authorization for the fuel cell projects by $1 million to $21.3 million. We authorize PG&E to recover $1 million above the cost recovery amount adopted in D.10-04-028 for the fuel cell projects.

6.5. Energy Procurement (EP) Administration Costs

PG&E forecasts expense and capital expenditures for its Energy Procurement (EP) organization. PG&E forecasts 2014 expenses of $61.8 million and DRA proposes $11.19 million reductions. TURN proposes $420,000 reductions. PG&E's 2014 expense forecast, together with DRA's and TURN's proposed reductions, is summarized in Table 6-31 of PG&E's Opening Brief. PG&E forecasts 2014 capital expenditures of $33.9 million, while DRA and TURN each recommend a reduction of $4.746 million. We address the disputed issues by MWC.

6.5.1. Energy Procurement Expense

6.5.1.1. MWC CT (Acquire and Manage Electric Supply)

PG&E forecasts $50.209 million for MWC CT, which represents the majority of EP's budget and is impacted by the four main factors for in 2014:

(1) Cost escalation;

(2) New compliance mandates, such as the 33% Renewable Portfolio Standard; AB 32 cap-and-trade implementation, the Qualifying Facility/Combined Heat and Power (QF/CHP) Settlement, and the Dodd-Frank Act;

(3) Internal initiatives to enhance customer reliability with continued progress and targeted completion of an Alternative Energy Procurement Headquarters that will allow PG&E to perform critical energy procurement operations in the event of an earthquake or major grid or supply disruption; and

(4) Process improvements that will increase operational efficiencies in EP.

PG&E described the number of employees needed for each function within the EP organization, and as well as each employee's responsibilities with regard to new compliance and regulatory requirements and processes. PG&E also describes the reliability and process improvements associated with the 2014 expense forecast as well as how escalation was determined.

DRA recommends a 14.5% reduction of $7.308 million in PG&E's MWC CT expense forecast for 2014. DRA developed its expense forecast primarily by using 2011 recorded expenses or historic averages. DRA argues that PG&E's expenses in this category have been relatively stable over the 2010-2012 periods, and that PG&E's 2011 imputed amount was $11.159 million more than actual 2011 expenditures. DRA claims that PG&E received funding for 19 positions in the 2011 GRC, but only filled three of those positions. DRA claims that PG&E can use embedded funds to pay for 2014 activities, and that PG&E does not require funding for the 37 additional positions.

PG&E argues that DRA's use of historic, unescalated expenses is inconsistent with the trend line for EP expenses. PG&E points to the increasing complexity of energy markets, and to recent regulation and legislation that will increase the level of complexity. PG&E argues that, since 2007, EP expenses have

trended higher as a result of this complexity and will continue to increase through 2014. PG&E claims DRA's proposed reduction of EP's expenses in 2014 is inconsistent with the trend and ignores regulatory and legislative changes which will increase the amount of work for the EP organization.

EP hired 89 employees between 2007 and 2011. DRA argues that this number of employees is sufficient to handle additional procurement and compliance obligations for 2014. PG&E argues that regulatory and compliance obligation changes since 2011 result in the need for additional resources.

PG&E's 2011 GRC settlement provided for imputed regulatory values by MWC but did not specify imputed amounts at the program level. Because PG&E as a whole overspent relative to its imputed targets, PG&E thus claims that customers are not being asked to fund these programs for a second time. California Air Resources Board's (CARB) delays in GHG cap-and-trade implementation prompted funds to be reallocated from EP's budget to other organizations within PG&E. This budget re-allocation was identified in PG&E's annual budget filing with the Commission.

Discussion

We reduce PG&E's forecast for MWC CT to exclude the increase of 12 positions. In all other respects, we find PG&E's MWC CT forecast reasonable and adopt it. While we conclude that some level of test year increase in funding over 2011 levels is warranted to meet new CARB and GHG mandates, we decline to approve funding for the full increase requested by PG&E. Ratepayers previously provided funding in the 2011 GRC for filling several positions to meet CARB mandates even though PG&E did not fill all of the positions on the basis forecasted. As explained by PG&E, due to delay of the cap-and-trade program by CARB (to January 1, 2013), PG&E deferred hiring some of the forecasted

staffing increase beyond the 2011 Test Year. PG&E reallocated these ratepayer funds to pay for other programs. Actual hiring amounted to only three additional employees in 2011. In 2012 and 2013, PG&E hired 12 more employees to meet the requirements of the first GHG cap-and-trade compliance period for electric supply, which began on January 1, 2013. PG&E plans to hire an additional 12 employees in 2014 to comply with the second GHG compliance period for natural gas, which is scheduled to go into effect on January 1, 2015.

While we conclude that PG&E is entitled to funding to meet new CARB compliance mandates not previously anticipated or funded, ratepayers should receive some recognition for staff positions that they previously funded in the 2011 GRC but where the hiring was deferred and the funds were redirected to other purposes. Consequently, we reduce PG&E's incremental funding by 12 positions, representing the hiring that was deferred until 2012 and 2013. We conclude that the funding that ratepayers previously provided in the 2011 GRC should count toward the cost of the 12 positions filled in 2012 and 2013. By reducing PG&E's funding to this limited extent, we also recognize that much of the CARB compliance work is not new, but represents ongoing responsibilities that are continuing into the 2014 GRC cycle. Accordingly, for such continuing work, PG&E should be able to manage without increased funding, and our reduced funding authorization provides a signal for PG&E to use workforce resources as efficiently as it can in meeting CARB compliance work.

6.5.1.2. MWC CV (Gas Procurement)

PG&E forecasts $6 million in 2014 expense for MWC CV, which represents the Core Gas Supply function, gas settlements, and GHG compliance for the natural gas sector scheduled to be implemented in 2015. PG&E argues that when new GHG compliance requirements are implemented in 2015 for the natural gas

sector, there will be a substantial need for additional staff. PG&E forecasts: (a) 12 employees for compliance associated with the second GHG compliance period; (b) four employees for commercial activities, including development of commercial strategies and positions, allowance and carbon offset credit procurement, and management of transfers and holding limits; (c) one employee for market monitoring and identification of market inefficiencies and aberrations; (d) four employees for contract management and settlements activities, including administration and settlement of emissions allowances and carbon offset credit purchases; and (e) three employees for project management and compliance activities.

DRA recommends a 36.2% reduction of $2.164 million in PG&E's forecast based on use of PG&E's 2011 actual expense amount. DRA claims that embedded funding for this MWC should be sufficient and that PG&E has already added substantial resources to its EP organization since 2007.

PG&E responds, however, that the natural gas sector has not yet been subject to GHG compliance, and thus, past funding levels do not capture the increased scope of work that will result from the new GHG requirements.

Discussion

We adopt PG&E's 2014 forecast for MWC CV. We conclude that PG&E has provided adequate explanation of its increased funding needs for 2014, including details concerning how additional employees will be utilized in addressing the additional regulatory requirements to be imposed on the natural gas sector as a result of new GHG requirements. We do not believe that reliance on 2011 embedded funding levels would be adequate since those historic levels do not reflect the new regulatory requirements taking effect in 2015. We also

recognize that PG&E's funding request here is separate from the GHG-related costs recoverable through the balancing account approved in D.12-12-033.

6.5.1.3. MWC JV (Maintain IT Applications and Infrastructure)

PG&E forecasts $3 million for MWC JV, which represents expenses associated with developing and implementing new software or systems to meet EP business needs.

DRA recommends a 57% reduction of $1.722 million in PG&E's forecast based on an average of 2009-2011 actual expense amounts. DRA argues that PG&E's proposal for developing and implementing new software or systems to be a one-time, non-recurring cost, such that additional funding is therefore not required each year during this rate case cycle. DRA also argues that PG&E has embedded funding that can address these IT expenses.

PG&E argues, however, that no previously authorized funding exists to specifically address the Central Data Repository or Document Management System forecasted in the 2014 GRC. The funding authorized in the 2011 GRC was used for different technology objectives.

PG&E explained that expenses in MWC JV have increased significantly because capital projects associated with the CAISO's Market Redesign and Technology Upgrade, recovered through a separate Commission-approved balancing account, have come on line and have expenses associated with them.

PG&E denies DRA's claims that PG&E deferred maintenance, upgrades, and consolidation activities of critical record storage systems. PG&E's also denies that its use of multiple systems of record and heavy reliance on time-consuming processes was inefficient or ineffective.

TURN also proposes a $420,000 reduction based on DRA's arguments concerning PG&E's Concept Estimating Tool.

Discussion

We conclude that PG&E has adequately justified its forecast for MWC JV and adopt it, except for the $420,000 reduction proposed by TURN based on PG&E's use of the Concept Estimating Tool. We conclude that embedded funding is insufficient to cover the increased funding needs for new software systems including the new Central Data Repository and Document Management System forecasted in the 2014 GRC. As discussed in Section 7.8.2., we adopt TURN's proposed $420,000 reduction based on DRA's arguments concerning use of PG&E's Concept Cost Estimating Tool.

6.5.2. Energy Procurement Capital

6.5.2.1. Build IT Applications and Infrastructure (MWC 2F)

PG&E forecasts $33.9 million in 2014 capital expenditures for IT costs associated with the development of in-house software solutions, as well as the purchase of external software vendor solutions, to meet specific business needs and compliance requirements within Energy Procurement. PG&E's overall request consists of the following: (1) $18.0 million to implement and enable CAISO Market and Performance initiatives; (2) $5.0 million to build a Central Data Repository that will integrate all of PG&E's Energy Procurement data; (3) $4.5 million for Settlement Quality Meter Data replacement by integrating, calculating, and analyzing meter data; (4) $4.0 million for Reporting Expansion by remediating the extensive use of spreadsheets; (5) $1.5 million for a Document Management project to help Energy Procurement with contract management; and (6) $0.9 million for a Forecasting project that will enhance forecasting and management of increasing renewable resources.

In Rebuttal, PG&E adopted DRA's 2012 forecast of $19.4 million for Energy Procurement IT costs. PG&E originally forecasted 2013 capital expenditures of $25.5 million. However, because PG&E's 2012 recorded spending is directly the result of the temporary delay in the implementation of CAISO initiatives, PG&E revised its 2013 forecast from $25.5 million to $40.5 million, so that the cumulative 2012 to 2014 forecast is unchanged.

DRA and TURN both recommend 14% reductions to PG&E's 2013 and 2014 forecasts based on PG&E's use of the Concept Cost Estimating Tool, resulting in reductions of $5.665 million in 2013 and $4.746 million in 2014.

Discussion

We adopt PG&E's 2013 and 2014 forecasts for Energy Procurement IT costs as reasonable. However, we also agree with the rationale behind the reductions proposed by DRA and TURN based on PG&E's use of the Concept Cost Estimating Tool, and duly reduce PG&E's 2013 and 2014 forecasts by 14%.

6.6. Energy Supply Ratemaking

6.6.1. Treatment of Department of Energy Litigation Proceeds

PG&E, TURN and MEA (i.e., the Joint Sponsors) present a joint recommendation for crediting to customer proceeds from PG&E's successful spent fuel contract litigation with the DOE.[73] The Joint Sponsors agree to a ratemaking method to credit the DOE litigation settlement proceeds to customers, net of litigation costs, as authorized in D.07-03-044.

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[73] *See* Exh. 330 (MEA, TURN, and PG&E Joint Testimony) at 1-3.

PG&E's lawsuit arises from a breach of a standard nuclear spent fuel disposal agreement with the DOE under which the DOE agreed to pick up spent fuel and to transport it to a permanent repository. No permanent repository has yet been established. All nuclear plant operators, including PG&E, sued the DOE to recover their costs to store fuel on site after it was due to be picked up. These cases were filed in the United States Court of Federal Claims and appealed to the Federal Circuit Court of Appeals. Those courts have issued a series of decisions determining that by failing to timely pick up fuel, the DOE committed a "partial breach" of contract, entitling the plant operators to damages. PG&E filed two lawsuits and has successfully prevailed in the first lawsuit and resulting appeals.

Litigation costs are currently recorded in the Department of Energy Litigation Balancing Account (DOELBA). When settlement funds are received, PG&E's accumulated outside litigation costs will be subtracted. The remainder of the proceeds will be recorded in the DOELBA and, consistent with D.07-03-044 Finding of Fact 16 and Conclusion of Law 14, PG&E was directed to file an application proposing to credit the litigation proceeds to customers, net of its litigation costs.

The Joint Sponsors agreed to a method for crediting the DOE litigation proceeds to generation rates and nuclear decommissioning rates as discussed below. Any additional funds received in 2014 through 2016, estimated at about $20 million per year, will be credited to rates on an actual basis. PG&E will continue to track actual costs in the DOELBA and true-up the forecast annually through an adjustment to generation rates in the Annual Electric True-Up. We adopt the terms of the Joint Sponsor's proposal on the ratemaking treatment of the DOE Litigation proceeds, as set forth in Appendix F.5.

7. Shared Services and IT

7.1. Introduction

PG&E's Shared Services includes the Safety Department, Transportation Services, Supply Chain, Real Estate, Environmental Programs, as well as IT. PG&E's 2014 Shared Services and IT expense forecast is $359.8 million (reduced from $364.8 million due to concessions), representing a $88.2 million increase over 2011 recorded costs of $271.6 million. PG&E attributes the increase to: Americans with Disabilities Act (ADA) compliance and facility maintenance; labor costs for additional safety professionals to provide improved field support; and escalating IT costs for maintenance contracts and licensing, plus increased headcount to support the growing deployment of devices, systems, and applications to support the LOB.

PG&E's Shared Services capital expenditure forecast is $332.1 million for 2012, $337.1 million for 2013, $460.1 million for 2014, $448.3 million for 2015, and $407.8 million for 2016. Capital cost drivers include: Transportation Services' vehicle replacement requirements; real estate costs to maintain aging infrastructure, ensure reliability of buildings that house critical business operations, and seismically upgrade buildings; a significant upgrade to the Company's primary procurement system; as well as major IT Lifecycle initiatives, implementation of three large Technology Reliability projects and two Continuous Improvement projects.

PG&E forecast costs for on-going O&M for IT projects and systems, as well as for new capital projects. PG&E argues that IT expenditures will improve safety and customer service, reduce the frequency and duration of outages, and ensure regulatory compliance.

The Liberty Report found that PG&E's spending forecasts for Shared Services, as related to safety issues, were not supported by risk assessments or cost-benefit analysis, but generally included written narrative arguments.

PG&E forecasts $261.6 million in IT expenses for 2014, a $45 million, or 20.7%, increase over 2011 recorded costs. The increase is primarily driven by escalating costs for maintenance contracts and licensing supporting the growth of assets as services, as well as increased IT-related headcount to support various initiatives proposed by PG&E's LOBs. IT is offsetting growth in expense amounts by reducing unit costs for various IT operations.

Although the IT organization supports other PG&E LOBs, each individual LOB is responsible for IT costs in its area. The enterprise-wide IT projects discussed here only represent a subset. PG&E forecasts $209.6 million in 2014 capital expenditures for the following enterprise-wide IT initiatives: (1) IT asset lifecycle initiatives; (2) Disaster Recovery to address IT risk mitigation; (3) Telecommunications Network Enhancement program to support grid modernization; (4) Identity and Access Management initiative to reduce enterprise risk and access to customer and employee information; (5) Records Management Archival program related to the availability of records; and (6) Service Management program to improve the reliability of IT operations.

7.2. Safety Department

PG&E's Safety Department is responsible for identifying, evaluating and controlling hazards, risks and exposures to protect PG&E employees and the general public. The department has focused on continuous improvement in occupational and public safety.

7.2.1. Safety, Engineering, and Occupational Safety and Health Administration Compliance (MWC FL)

PG&E's forecast for the Safety Department's 2014 expense for MWC FL is $15.587 million. PG&E seeks funding to hire 21 additional safety professionals to support field operations, and implement IT solutions to improve safety work management which include: (1) a Safety Audit/Assessment Program ($0.225 million); (2) a Contractor Safety Program ($0.15 million); (3) a Pandemic Supplies and Materials program ($0.275 million); and (4) a document integration to an Enterprise Content Management System ($0.25 million).

PG&E argues that adding 21 safety professionals is warranted to enhance technical safety expertise, guidance, and support for field employees. Each safety professional can spend more time at worksites and less time driving to worksites. PG&E argues that hiring these additional safety professionals is consistent with industry best practices. A benchmarking study concluded that PG&E's current safety professional-to-total employee ratio – one safety professional for every 280 employees – lags behind other utilities. After hiring 21 more professionals, PG&E's ratio will be one professional for every 217 employees, which will still be higher than comparable utilities' ratios.

DRA recommends a $2.66 million reduction to PG&E's forecast for MWC FL, relying upon a five-year average of recorded costs as the basis of its forecast. DRA claims that PG&E has not justified the need to fund additional positions. DRA notes that PG&E had seven vacant safety positions at the end of 2011, and questions the need to add more positions given these vacancies. PG&E responds that while staffing levels fluctuated in 2011, PG&E's 2014 forecast includes filling the seven vacancies plus hiring the 21 additional safety professionals.

DRA notes that the ratio of PG&E Safety Department employees to total company employees has remained relatively unchanged over the five years of recorded historical data. DRA calculated the ratio PG&E's active employees in the Safety Department to the number of PG&E's IBEW employees over the same five years. DRA claims that the ratio did not change in those five years. DRA believes the addition of 21 new staffing positions would be at odds with those historic ratios.

PG&E disagrees with DRA's reliance on a five-year average of past costs as a sole basis for a forecast. PG&E argues that such an analysis presumes that IT initiatives for new or enhanced programs would never be approved if PG&E did not previously request or spend on IT projects. PG&E argues that employee and public safety assessments cannot be limited to an accounting review. PG&E also argues that DRA's position promotes a status quo culture rather than one favoring enhancements to safety.

Discussion

We adopt PG&E's 2014 forecast for MWC FL, and conclude that PG&E has reasonably justified its requested increase in safety professionals. We conclude that reliance on historic spending levels does not reflect the level of safety support warranted for 2014. Based on PG&E's internal assessments, there have been insufficient numbers of safety professionals to provide an appropriate level of support to field employees. This conclusion was supported by analyzing the number of miles driven by safety professionals and by benchmarking with other utilities.[74]

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[74] Ex. 31 (PG&E -7 WP 02-05) WP 2-18.

We conclude that the benchmarking study offered by PG&E presents a reasonable basis to assess the number of safety professionals needed. Relative to ratios of safety personnel to total employees in the benchmark results, we conclude that PG&E's request for 21 additional positions is reasonable. Allowing funding for the requested increase in safety positions is supported by Liberty Consulting Group report findings that:

> [t]he addition of safety personnel is in line with other electric utilities and should contribute to improving field safety. The number of additional safety personnel being added will position PG&E in line with other utilities that are top performers in safety.[75]

DRA's calculation of the ratio of Safety Department employees to IBEW employees reflects only a sub-set of employees. PG&E's goal, however, is to improve the ratio of safety employees relative to all employees. DRA argues that by that rationale, the number of secretaries determines Safety Department needs to the same extent as do field employees who do more dangerous work.

We recognize that more accurate measures of safety personnel needs might be calculated by separately considering differences in risks and safety issues relating to field versus office employees. The benchmark results before us, however, are based on averages for all employees. To varying degrees, all employees experience safety risks. PG&E has not separately delineated different safety risks and mitigation measures by employee category, but it is reasonable to evaluate PG&E's overall requirements for safety professionals based on the same metric used for identifying the industry benchmark. As PG&E notes,

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[75] Liberty Report at 154.

consideration of safety personnel relative to total workforce is an industry best practice.

7.2.2. Applications and Infrastructure Maintenance (MWC JV and 2F)

PG&E forecasts $760,000 in 2014 expenses for Safety, Engineering, and Health Services Work Management IT initiatives in MWC JV. PG&E's proposal is driven by an Environmental, Health and Safety (EHS) Compliance Management System to manage regulatory compliance in a systematic manner; to track, monitor, and execute on all safety commitments and corrective actions; and to monitor work as it is requested by clients and assigned to a safety professional. Other projects in this MWC forecast are to: (1) improve communication of Proposition 65 and asbestos notifications ($0.31 million); and (2) integrate safety-related documents into an Enterprise Content Management system ($0.20 million).

DRA proposes reductions of $717,000 to PG&E's forecast for MWC JV, basing its forecast of $43,0000 on average recorded expenditures from 2009-2012. DRA argues that PG&E did not spend on IT initiatives in prior years, and that no evidence indicates that PG&E will deviate from this spending pattern in 2014.

PG&E forecasts 2014 capital expenditures in MWC 2F of $0.145 million to implement IT initiatives. DRA recommends zero funding for these IT initiatives based on the lack of any recorded costs in this MWC for the past six years. DRA also claims that PG&E did not provide sufficient evidence to indicate it will deviate from this past pattern. DRA proposes reduction of the capital forecast to reflect its 14% adjustment relating to projects forecasted using PG&E's Concept Cost Estimating Tool. TURN recommends a $0.02 million reduction.

Discussion

We approve funding of 2014 expenses and capital expenditures for the Safety, Engineering, and Health Services Work Management IT initiatives proposed by PG&E in MWC JV and 2F, respectively. We reduce PG&E's 2014 forecasts in MWC JV of $0.760 million and MWC 2F of $0.145 million by 14%, however, adopting DRA's general recommendation regarding estimates based on PG&E's Concept Cost Estimating Tool.

We conclude that PG&E's proposed IT initiatives are justified to improve safety performance. As PG&E explains, current processes involve inherent risks in missing compliance deadlines, rendering it difficult to gain a holistic view of Safety Department commitments. The EHS system will enable PG&E to monitor work as it is requested by clients and assigned to a safety professional.

We decline to adopt DRA's forecast for MWC JV based on historic spending patterns. We also decline to adopt DRA's proposal for zero funding for MWC 2F. DRA didn't provide substantive objections to the new IT programs proposed by PG&E, but relied on past spending patterns. We conclude, however, that PG&E's spending pattern in prior years does not justify perpetuating those past patterns by denying necessary test year funding.

7.3. Transportation Services

PG&E's Transportation Services (TS) operates and maintains more than 12,000 vehicles and pieces of equipment, and maintains 72 garages (61 staffed) with 404 active fleet employees. PG&E employees drive more than 110 million miles annually to serve customers. PG&E also maintains an airplane, principally to serve DCPP operations. PG&E proposes five key TS initiatives for the 2014 rate case period: (1) Vehicle Replacement; (2) Vehicle Safety and Operational Monitoring System; (3) Consolidation of the DOT Compliance Group:

(4) Consolidated Rotary Division in Aviation Services; and (5) Reduce Long-term Rental Costs

DRA proposed the following reductions to PG&E's TS forecast: (1) $33.8 million in capital expenditures in 2014, and $69.2 million in capital in 2013, impacting TS' purchase of low air emissions vehicles to comply with California regulations; (2) $14.0 million in the gasoline and diesel fuel forecast in 2014; (3) $1.5 million in capital and $1.8 million in expense for IT improvements in 2014; (4) $0.520 million for tools and equipment in 2013; (5) $0.200 million to expand electric vehicles charging infrastructure in 2013 and $0.482 million in 2014.

7.3.1. Transportation Services Fuel Expense

PG&E forecasts $42.725 million for fuel expenses for its vehicle fleet (reduced from $49.1 million), derived by assessing historic fuel values (WP 3-365). From this historic data, PG&E assessed TS' current and projected total Company chargeback cost requirements in light of the actual condition and quantity of fleet units.

DRA recommends a 2014 forecast of $35.1 million. DRA's proposed reduction is based on a lower estimated unit cost of fuel, derived from the California Energy Commission Energy Almanac's April 22, 2013 retail price for gasoline and diesel fuel. DRA further adjusted this forecast to reflect fuel savings from PG&E's fleet of new electric vehicles.

PG&E claims that DRA's forecast is incorrect based on a number of errors, including DRA's assumptions regarding fuel price and the savings in gasoline consumption resulting from replacements of vehicles.

Discussion

We adopt PG&E's 2014 forecast of $42.725 million in fuel expenses for its vehicle fleet. We conclude that PG&E's assumptions regarding fuel expense are reasonable as a basis for its forecast.

We find insufficient basis to adopt DRA's proposed reductions in fuel expense. DRA calculated its fuel cost forecast using the following formula:

> (Fuel price per gallon) X (Estimated # of gallons consumed in a year) = (Annual fuel forecast).

The unit retail price per gallon of gasoline and diesel fuel in DRA's formula does not adequately account for price fluctuations, but is based on one week of fuel prices from April 22, 2013. Fuel prices fluctuate during a year, however, and can fluctuate significantly year-to-year.

PG&E proposed an alternative fuel forecast using the same reference source as DRA, but accounting for price fluctuation by averaging a two-year, not a one-week, period. Relying on this two-year average, PG&E calculated a forecast of $42.725 million.

Although DRA estimated the amount of fuel saved or displaced by assuming that PG&E will deploy 1,076 all-electric vehicles starting January 1, 2014, PG&E anticipates purchasing only 341 plug-in hybrid vehicles in 2014 and deploying them, on average, only in the last three months of 2014.

DRA assumes an electric vehicle displaces 125 gallons of fuel per month, or more than 1.5 million gallons of fuel in 2014. PG&E claims, however, that less than 130,000 gallons of fuel will be displaced after 341 vehicles are deployed. DRA assumed that the replacement vehicles will be 100% electric vehicles. PG&E also plans to deploy plug-in hybrid gasoline and electric vehicles, rather than all-electric vehicles, as DRA assumes. PG&E's hybrid electric vehicles,

however, will still consume some gasoline. The plug-in hybrid vehicles will primarily replace natural gas vehicles. We thus conclude that DRA's forecast of fuel expense is based on erroneous assumptions.

7.3.2. MWC JV: Risk Management Improvements

PG&E forecasts $3.12 million in 2014 expenses in MWC JV to implement five IT projects that PG&E claims will significantly improve its risk management.

DRA recommends a reduction of $1.77 million to PG&E's forecast for MWC JV. TURN recommends a reduction of $0.437 million. DRA does not oppose the business justifications for: (1) Vehicle Safety and Operational Tracking and Reporting ($1 million); (2) IT Infrastructure Optimization ($0.25 million); and (3) Field Enablement of IT Systems in Garages ($0.1 million). Both DRA and TURN propose reductions to the forecast expense and capital by 14% because the forecasts were based on PG&E's Concept Cost Estimating Tool.

DRA proposes zero funding for two IT initiatives: (1) a Compliance Tracking and Reporting System ($1.1 million); and (2) a Fleet Management Optimization upgrade ($0.67 million). DRA opposes these initiatives claiming that PG&E does not identify cost savings and non-cost benefits are questionable and unverifiable. DRA claims there is no evidence that PG&E's Transportation Compliance Management Tracking and Reporting needs $1.1 million of improvement.

Discussion

We approve 2014 funding in MWC JV for PG&E's five proposed IT initiatives, but reduce PG&E's forecasted expense in MWC JV by 14% because the forecast was developed using PG&E's Concept Cost Estimating Tool. We conclude that funding is warranted to enable PG&E to implement the five IT

projects proposed to improve risk management. There is no opposition to three of the IT projects. Although DRA opposes funding for two of the IT projects, we conclude that funding for them is warranted in view of the expected benefits. Although the immediate costs of the two initiatives exceed measurable savings, we conclude that the indirect benefits justify funding. The Compliance Tracking and Reporting System will transfer paper processes to an electronic digitized system to improve the speed and accuracy of ensuring compliance with U.S. Department of Transportation safety requirements for operating heavy equipment and large vehicles. The Fleet Management Optimization upgrade will improve key systems that manage vehicle licensing, purchase, replacement, and maintenance. We believe these initiatives will appropriately mitigate negative consequences of poor business practices and warrant funding.

7.3.3. TS Capital Expenditures

PG&E's 2014 TS capital forecast of $139.3 million is comprised of vehicle purchases, electric vehicle charging infrastructure, IT initiatives, and tools and equipment. The TS capital expenditures are to meet state emission mandates, replace fleet units exceeding established lifecycles, maintain an environmental leadership role, replace capital tools and equipment used to service PG&E's fleet, provide EV charge points for PG&E's fleet of plug in vehicles, and improve IT systems performance and update capabilities. PG&E's capital expenditure estimate factors in Global Insights escalation data for the range of vehicles planned to be deployed for equipment replacements. Disputed elements of the TS 2014 capital forecast among PG&E, DRA, and TURN are as follows:

	($ in millions)	Proposed Reductions	
Item	**PG&E**	**DRA**	**TURN**
MWC 04 – Fleet Auto Equipment	$132.908	-$33.758	
MWC 28 – EV Station Infrastructure	$2.412	-$482	
MWC 2F – Build IT Apps and Infrastructure	$3.050	-$1.450	-$0.427
MWC 05 – Tools and Equipment	$933	_____	_____
Totals	$139.303	-$35.69	-$0.427

DRA accepts PG&E's actual 2012 recorded costs and decreased PG&E's forecasted 2013 capital expenditure by $33.8 million, equal to the amount by which PG&E exceeded its 2012 forecast. DRA agrees with the MWC 05 forecast of $0.933 million for 2014 only. We address the disputed issues relating to TS capital expenditures below.

7.3.3.1. Fleet Auto Equipment (MWC 04)

PG&E forecasts $132.908 million in 2014 capital expenditures for Fleet Auto Equipment in MWC 04 associated with TS' vehicle fleet replacement program. PG&E's 2012 capital expenditures forecast is to provide vehicles for an additional 40 gas service representatives (GSRs). PG&E's $13.4 million forecast for 2013 includes purchasing additional vehicles for maintenance and construction to support increasing capital and O&M work. DRA's capital forecasts for 2012-2014 in comparison to PG&E are as follow:

($ in Millions)

	PG&E	DRA
2012	$137.870	$171.690
2013	$145.464	$89.633
2014	$132.908	$99.150

DRA proposes to reduce PG&E's 2014 budget by $33.8 million based on the premise that PG&E exceeded its 2012 budget by this amount. PG&E claims, however, that for the two-year period of 2011-2012, PG&E actually underspent its budget by $23 million. PG&E expected to take delivery of several vehicles in 2011, but, because of manufacturers' delays, PG&E did not receive and pay for these vehicles until 2012. Thus, PG&E disputes DRA's reduction to 2013 based on the incorrect premise that PG&E overspent its budget.

As a basis for its 2013 and 2014 forecast, DRA calculated the average unit costs of 2011 and 2012, and applied this average unit cost to the forecasted number of PG&E's on-road replacement units, escalated by non-labor rates. PG&E argues, however, that DRA did not calculate unit costs correctly. PG&E claims that DRA's funding recommendations would prevent PG&E from complying with legal requirements, subjecting it to penalties up to $10,000 per day.

Discussion

We adopt PG&E's 2012-2014 capital forecasts of Fleet/Auto Equipment capital expenditures for MWC 04, and conclude that the forecast reasonably reflects costs due to regulatory compliance, replacing vehicles at the end of their lifecycle, and buying additional vehicles. PG&E's capital estimate is based on a five-year plan that assesses the lifecycle of each piece of equipment, the quantity due for replacement, and subsequent costs. In 2014, 75% of the capital budget forecast is to comply with state and federal regulations. The principal obligation is a Heavy-Duty Diesel Agreement negotiated between PG&E and the CARB, resulting in an "Alternative Compliance Schedule" affecting a heavy-duty fleet of primarily diesel vehicles.

To meet deadlines, PG&E will replace a minimum of 1,030 units between 2014 and 2016. PG&E lacks discretion to determine a replacement schedule, but is subject to specific dates on which the vehicles need to be replaced. The remaining vehicle purchases are: (1) to replace vehicles that have or will reach the end of their full lifecycle during this rate case period; and (2) to support increased work activity in Gas Operations. PG&E is required by state regulations to replace targeted vehicle categories within specific time frames based on age, mileage, and vehicle condition.

PG&E forecasts purchasing 470 new vehicles in 2013, totaling $114.3 million, and 309 new vehicles in 2014, totaling $80.3 million, for environmental compliance. Vehicle replacement costs in this GRC cycle exceed historical costs due to differences in the type of vehicles planned for replacement. Replacement vehicles must meet state and federal environmental laws.

We decline to adopt the reductions proposed by DRA. DRA calculated separate average unit costs for two separate vehicle compliance groups, while PG&E calculated an overall weighted average unit cost for both vehicle compliance groups. PG&E calculated 21% for 2012 and 18.5% for 2013.

PG&E forecasts, budgets, and purchases its vehicles out of its MWC 04 budget, regardless of the CARB Vehicle Group. PG&E relied on the same information as DRA to calculate an average price per vehicle, but combined to calculate a fully weighted average cost. PG&E's calculations demonstrate an average price increase of 18.45% for 2013 over 2012.

DRA claims that average unit costs increased 42% to 52% from 2012 to 2013 for On-Road compliance, while historical unit averages have only increased 23% to 25%. DRA claims that the increase from historical norm is not reasonable and should be adjusted. DRA applied an average 2011- 2012 unit cost to the

number of PG&E's On-Road replacement units, yielding a reduced vehicle purchase forecast by $35.4 million in 2013. DRA also used an average of 2011 and 2012 unit cost, escalated to non-labor rates, and applied that to PG&E's 2014 forecasted total units for PG&E's On-Road replacement to forecast a 2014 capital budget.

DRA's forecast is in error with respect to: (1) the assumed in-service date for the new vehicles; (2) the type of vehicles deployed; and (3) the type of vehicles to be replaced. DRA assumes all new vehicles are deployed on January 1, 2014. PG&E plans to deploy the vehicles in groups, however, spread over a three-year period. On average, PG&E plans to place each group of new vehicles into operation only during the last three months of each year.

7.3.3.2. MWC 05 – Capital Tools and Equipment

PG&E forecasts costs for fleet-related capital tools and equipment and maintenance and updating of environmental equipment in MWC 05. PG&E's 2012 forecast for MWC 05 was $900,000, but its 2012 recorded cost was $1.42 million. PG&E forecasts $908,000 in 2013 and $933,000 in 2014 for MWC 05. DRA accepts PG&E's total three-year (2012-2014) capital expenditure forecast for MWC 05, but reduces PG&E's 2013 MWC 05 capital forecast by $520,000 to compensate for PG&E exceeding the 2012 forecast by the same amount.

Discussion

We adopt PG&E's MWC 05 capital expenditure forecasts of $900,000 in 2012, $908,000 in 2013, and $933,000 in 2014. Parties agree on 2014 amounts. PG&E objects to DRA's proposed reduction for 2013, arguing that the higher-than-forecasted spending in 2012 does not affect the 2013 budget. Our adopted amounts recognize PG&E's 2013 forecast for MWC 05 as reasonable.

Although DRA proposes a reduction for 2013, DRA proposes to apply a higher 2012 figure than PG&E forecasted. The forecasted differences between PG&E and DRA for 2012 and 2013 offset each other, resulting in a net zero difference overall. Thus, by adopting PG&E's forecast amount for MWC 05 for all three years, there are no net differences in forecasted totals to resolve between PG&E and DRA overall.

7.3.3.3. MWC 28 – PEV Charging Infrastructure

PG&E forecasts costs for developing new electric powered vehicles charging infrastructure and anticipates an increased need for such charging infrastructures for its fleet of electric vehicles (EVs). Recorded capital expenditure for EV charging infrastructure in MWC 28 was $215,000 in 2011. PG&E forecast $680,000 in 2012; $200,000 in 2013; and $2.4 million in 2014. The escalation of these costs in 2014 is based on PG&E's projected addition of 743 light-duty EVs and 333 medium-and heavy-duty EVs from 2014-2016. PG&E claims that TS will install 962 Level 2 (220v) charging stations and 126 Level 1 (120v) charging stations to support the increase in EV vehicles.

DRA accepts PG&E's actual 2012 recorded costs, but proposes eliminating PG&E's forecasted 2013 capital expenditures. DRA reduces PG&E's 2014 forecasted capital for MWC 28 by 20% based on data showing that actual costs were 20% lower than the forecast for completed EV charging projects.[76] DRA claims that there is no evidence to support how PG&E determined the number of charging stations necessary to support the increase in EV vehicles. PG&E claims

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[76] *See* updated workpaper WP3-223 provided in data response GRC2014-Ph-1_DR_DRA_153Q13; Ex. 86 (DRA-18) at 21.

that DRA relied on interim costs rather than final costs for MWC 28 as the basis for its recommendation. PG&E's 2012 final costs were actually $0.383 million more than the forecast. PG&E also argues that there is no sound basis to reduce a forecast merely because spending was below forecasts in a preceding year.

Discussion

We adopt PG&E's 2012-2014 forecasts for MWC 28. We conclude that PG&E reasonably justified its forecasts. We find no basis to adopt DRA's proposal to eliminate MWC 28 funding for 2013. We also are not persuaded by DRA's argument that the 2014 forecast should be 20% lower merely because PG&E spent below its 2012 forecast by 20%. We find no basis to conclude that the level of spending during 2012 invalidated PG&E's forecast for 2014 spending. DRA's reductions are based on interim costs, even though the final costs were available and higher than interim numbers.

7.3.3.4. MWC 2F – Build IT Applications and Infrastructure

PG&E forecasts $3.05 million in 2014 capital expenditures in MWC 2F relating to the five IT initiatives discussed above. Consistent with its proposal for IT expense projects for TS, DRA proposes zero capital funding for the Compliance Tracking and Reporting System and a Fleet Management Optimization upgrade. PG&E disagrees.

Discussion

Consistent with our prior discussion and approval of MWC JV expenses, we also approve PG&E's capital forecast of $3.05 million relating to the five IT initiatives for MWC 2F, but consistent with our discussion in Sec. 7.8.2.7, we reduce PG&E's forecast by 14% since the forecast was developed using PG&E's Concept Cost Estimating Tool.

7.4. Supply Chain

7.4.1. Materials and Logistics and Planning

PG&E's Supply Chain Department – Materials, Logistics, and Planning (MLP) provides warehousing, transportation logistics, supplier quality assurance, materials field services, inventory planning and control, and emergency response. PG&E's 2014 expense forecast of $1.321 million for MLP services, along with reductions proposed by DRA and TURN, are itemized below:

	($ in 000s)		
Description	**PG&E forecast**	**DRA**	TURN
		Proposed Reductions	
MWC Item			
MWC JV –Transport Management System	$225	-$31	-$31
JV – Advanced Planning/Scheduling	$885	-$885	-$124
BI – Building Materials	$221		-
Total	**$1,321**	**-$916**	**-$155**

PG&E's capital forecast for MLP is $7.848 million, for a 52% decrease from 2011 levels. The main elements are warehouse storage structure construction and implementation of an Advanced Planning/Scheduling (APS) system. PG&E's 2014 capital expenditure forecast for MLP services, along with reductions proposed by DRA and TURN, are itemized below:

	($ in 000s)	**Proposed Reductions**	
MWC Item Description	**PG&E forecast**	**DRA**	TURN
MWC 2F –Transport Management System	$737	-$103	-$103
MWC 2F- APS System	$3,530	-$3,530	-$494
MWCs 05, 21, and 22	$3,581	0	0
Total	**$7,848**	**-$3,633**	**-$597**

DRA opposes the APS System. No party opposes the Transport Management System; however, DRA and TURN both support a 14% reduction to PG&E's Transport Management System forecast based on use of the Concept Cost Estimating Tool.

DRA opposes funding for the APS system, based on the argument that the funds for this project were previously authorized in the 2011 GRC forecast, but implementation was deferred. DRA argues that because PG&E already received funds for this project, ratepayers should not have to fund the project twice. PG&E argues that the implicit premise of DRA's opposition is incorrect because the Commission adopted a lower revenue requirement than what PG&E requested. As a result, PG&E argues that it had to reassess the scope of work it could accomplish with less funding, and the APS project was rescheduled so that more essential work could be done.

PG&E explains that its current inventory management system does not offer network transparency necessary to optimize inventory levels while maintaining product availability in the right locations. The current system's forecasting capability cannot accurately forecast sporadic demand patterns. Consequently, PG&E claims that the APS system is warranted to improve access to materials for utility crews and optimize inventory levels, and that ratepayer funding is warranted to pay for it.

Discussion

We adopt PG&E's capital and expense forecasts for MLP, as itemized above, except for a reduction of 14% based on adoption of DRA's adjustment relating to PG&E's use of PG&E's Concept Cost Estimating Tool. In other respects, we decline to adopt DRA's proposed reductions to PG&E's MLP forecasts. We conclude that the APS system is a cost-effective program that

should be implemented. The question is whether PG&E's forecast for the APS System should increase the 2014 revenue requirement in view of the GRC funding for this program in 2011. As discussed in reference to other instances of postponement of programs where funding had been authorized, we do not believe that merely because funds were reallocated to pay for other programs, ratepayers should necessarily have to fund the same program again.

The expected savings from implementing the APS system are expected to exceed PG&E's forecast of program costs over time. PG&E expects to realize inventory investment savings of $5 million and capital investment savings of $3 million by the end of 2016. Given these expected savings that will benefit ratepayers, we find it appropriate to approve some degree of funding for the APS system for the 2014 GRC. We reduce PG&E's APS forecast by 14%, however, to incorporate DRA's adjustment for use of the Concept Cost Estimating Tool. This 14% reduction provides some mitigation in recognition of the concern raised by DRA that PG&E's forecast may include certain costs that were previously funded in the 2011 GRC.

7.4.2. Materials and Supplies Inventory

PG&E forecasts $132.7 million in 2014 for materials and supplies (M&S) inventory to support maintenance programs and NRC and Institute of Nuclear Power Operators-mandated systems and regulations. Forecasted increases cover: (1) Fossil Plant Facilities-M&S inventory for three generating stations that began operation in the last four years and for components used to reduce the length and cost of outages; (2) Hydro Facilities M&S inventory to reduce the length of outages at the Helms Power Plant; and (3) Nuclear Facilities-M&S inventory to support new systems at DCPP to ensure that critical systems have spare parts for routine maintenance or in the event of a failure, and meet

regulatory requirements. Keeping spare components in inventory will shorten the duration of a preventive maintenance outage by allowing PG&E to swap out the worn components rather than refurbishing them during maintenance outages. Limiting the duration of power plant outages reduces the need to purchase higher-priced electricity and promotes efficient plant operations.

DRA recommends a 2014 forecast of $114.0 million for EG M&S Inventory, for a reduction of $18.693 million compared to PG&E's forecast. DRA based its forecast on a six-year linear regression analysis using 2007-2012 historical data for Fossil Facilities, Hydro Facilities, and DCPP Generation Facilities.

Discussion

We adopt PG&E's forecast of $132.7 million for M&S inventory, and conclude that PG&E reasonably justified its forecast. We decline to reduce the M&S inventory forecast based on use of a six-year linear regression. We conclude that DRA's linear regression methodology fails to account for changed conditions regarding inventory needs that are not reflected in historic regression data. Since PG&E's fossil plants consist of three generating stations that began operation within the last four years, a six-year linear regression does not capture increased inventory requirements for these new plants. The six-year regression analysis also does not capture the increased requirements to have inventory on hand at the DCPP, as directed by the NRC in the wake of the Fukushima incident.

7.5. Supply Chain – Sourcing Operations

The Supply Chain – Sourcing (Sourcing) organization is the functional lead for the procurement of materials and services at PG&E, accounting for more than $4.4 billion of goods and services annually. PG&E's 2014 expense forecast for Sourcing Operations is $13.077 million, representing a $6.4 million increase over

2011 recorded expenses. The key driver to the forecast is an upgrade to the primary purchasing system: the SAP Supplier Relationship Management (SRM) System. Other drivers are initiatives to enhance the Supply Chain Sustainability, Supplier Diversity, and Diversity Technical Assistance Programs.

7.5.1. Diversity and Sustainability Programs (MWC JL)

PG&E forecasts $9.732 million in MWC JL for its Diversity and Sustainability Programs. The programs are designed to improve administration of the Commission's diversity certification database. PG&E's planned enhancements will include more robust training, support, and business development assistance programs). These enhancements are in accordance with Commission General Order 156. PG&E used 2011 as the base year for its forecast and escalated labor and non-labor costs based on its own escalation guidelines. The average cost per employee was determined from historical labor and related costs and used to adjust for additional headcount costs.

Based on a five-year (2008-2012) average of recorded costs, escalated to 2014 dollars, DRA recommends a 2014 forecast for MWC JL of $7.328 million. DRA claims that a five-year average is an appropriate test year forecasting basis as the recorded amounts lack a clear pattern and year-to-year variances are low, with movement in both directions. DRA thus recommends a $2.404 million reduction for purchasing and diversity efforts.

PG&E argues that if DRA's analysis was accepted, it would be appropriate to adopt an $8.934 million forecast because DRA's analysis did not account for all costs associated with procurement activities appropriately within MWC JL – Procure Materials and Services.

For two of the years included in DRA's analysis, 2008 and 2009, MWC JL recorded only internal labor costs for purchasing and procurement activities. In this time period, MWC FA recorded procurement activities performed by consultants. Beginning in 2010, PG&E ceased using MWC FA, and MWC JL recorded internal and consultants' costs for procurement. For MWC FA, recorded costs were $2.373 million in 2008 and $5.034 million in 2009. Once these MWC FA costs are added into DRA's calculation, a five-year average of expenditures is $8.934 million.

Discussion

We adopt PG&E's forecast of $9.732 million for MWC JL for its Diversity and Sustainability Programs, and conclude that PG&E justified its forecast based on improvements to administration of the Commission's diversity certification database.

We decline to adopt DRA's proposed reductions. DRA did not account for all applicable recorded costs in its calculations. Reliance on past costs doesn't account for new programs to be funded through MWC JL. DRA offers no substantive objections to the proposed programs that PG&E seeks to fund through MWC JL. We find that these proposed programs offer benefits that justify their funding.

7.5.2. Upgrade to SRM Purchasing System (MWC JV)

PG&E forecasts $3.345 million in 2014 expenses in MWC JV, consisting of: (1) $2.545 million to upgrade its SRM system to control risk of instability and/or failure of purchasing systems due to outdated technology; (2) $0.5 million to implement Supplier Performance Management Technology to enhance the relationship with key suppliers that provide critical goods and services; and

(3) $0.3 million to integrate Supply Chain with Enterprise Content Management (ECM) by digitizing physical documents and migrating records to PG&E's ECM system.

The current SRM system, created in 2006, is outdated. SAP ceased all support for it in March 2013. An upgrade is required to mitigate the risk of instability or long-term, Company-wide failure of its purchasing system. PG&E seeks funding to upgrade the SRM system to Version 7.02 at a cost of about $17.8 million, of which $2.7 million is forecasted for 2015 and is not included in this GRC forecast. The 2014 forecast expense for the SRM upgrade is $2.5 million.

DRA does not oppose PG&E's proposal to upgrade the SRM to Version 7.02, but recommends that the 2014 expense be reduced based on a normalization methodology by apportioning the 2014 expense forecast over a 3-year period. DRA also proposes that the forecast amount be reduced to 86% since the forecast relied on PG&E's Concept Cost Estimating Tool.

DRA recommends no funding for the Supplier Performance Technology system, reducing PG&E's forecast by $0.5 million, claiming the program does nothing more than formalize meetings and appears to be paying PG&E's employees to do the work they are already paid salaries to do.

PG&E responds that the proposed technology will achieve much more than schedule meetings, but will also enhance relationships with key suppliers of critical supplies and services. Suppliers are required to achieve a minimum score of 90 out of a potential 100 points in six key areas: safety, cost effectiveness, operations and quality, green/sustainability, supplier diversity, and client satisfaction. This formalized scoring system provides a benchmark to measure the performance of PG&E's suppliers.

PG&E's current scorecard process requires extensive manual effort to populate and update, delaying performance data by up to six months. The new system would have links and interfaces to data sources to pull information without intervention, with portals for suppliers to input information on a real-time basis. This would allow weekly or monthly views of supplier performance.

PG&E's third IT initiative for Supply Chain Sourcing would integrate Supply Chain Sourcing with ECM by digitizing physical documents and migrating the existing content to the ECM platform at a cost of $0.3 million for 2014.

PG&E argues that electronic storage of records is essential for traceability, and is a critical in today's business environment. Although records can continue to be stored in paper form, doing so presents risk, issues regarding location, cost of physical storage and retrieval, lack of centralization, and increased time to access if needed quickly.

DRA opposes funding the integration of Sourcing's documents into PG&E's ECM system. Given the areas in this GRC that PG&E has requested digitizing physical documents as part of the migration to its new ECM platform, DRA claims that ratepayers are probably already duplicating funding for this process in this and earlier GRCs.

Discussion

We adopt PG&E's expense forecast for MWC JV, except for a reduction of 14% to reflect DRA's adjustment for use of PG&E's Concept Cost Estimating Tool. Based on the expected benefits, we thus approve funding for PG&E's proposals to (1) upgrade its SRM to control risk of instability and/or failure of purchasing systems due to outdated technology; (2) implement Supplier

Performance Management Technology to enhance the relationship with key suppliers that provide critical goods and services; and (3) Integrate supply Chain with ECM.

We find that the benefits to customers from implementing these programs justifies their funding. We decline to adopt DRA's proposal to normalize the 2014 expense forecast over a three-year period. DRA's proposed normalization would reduce PG&E's 2014 forecast by two-thirds and would thus not provide sufficient funding to implement the programs as planned for 2014.

7.5.3. Supply Chain Sourcing Capital Expenditures

PG&E's capital forecast for Supply Chain Sourcing IT initiatives is $10.02 million for 2014 and $4.8 million for 2015. Of these amounts, the SRM Technical/Functional Technology upgrade is $8.5 million for 2014 and $4.1 million for 2015. The only other capital forecast for an IT initiative is for Integrating Supply Chain with ECM, for which PG&E forecasted $1.6 million in 2014 and $0.7 million in 2015.

Consistent with DRA's recommendations under MWC JV, DRA supports capital funding for the SRM Technical/Functional Technology upgrade program, but reduces PG&E's forecast by 86% to reflect PG&E's use of the Concept Cost Estimating Tool. This would reduce PG&E's 2014 forecast of $10.02 million to $7.3 million.

Discussion

Consistent with our treatment of Supply Chain expense funding, we approve PG&E's capital expenditure forecasts for its Supply Chain Souring IT initiatives, with a reduction of 14% applicable to the amounts forecasted with the use of the Concept Cost Estimating Tool

7.6. Corporate Real Estate

PG&E's Corporate Real Estate Department manages over 7.4 million square feet of office and support space in 833 facilities. These facilities include offices, service centers, shops, warehouses, and garages. These facilities support day-to-day business operations, as well as service restoration during natural disasters and other emergencies.

PG&E forecasts 2014 expense of $32.59 million for Corporate Real Estate activities, an increase of 172% over 2011 expenses. PG&E's Real Estate capital forecast is $81.602 million for 2014. PG&E attributes the cost increases to improving aging buildings and yards, maintaining reliability of buildings, providing office space, buildings, and yards, completing seismic safety upgrades, improving building accessibility, and disposing of real estate that is not needed.

7.6.1. Real Estate Forecast Overview

PG&E's expense forecast for Corporate Real Estate activities by MWC, together with DRA's and TURN's proposed reductions, are summarized as follows:

($ in Millions)

Item Description	**PG&E Forecast**	**Proposed Reductions**	
		DRA	**TURN**
MWC BI-Maintain Buildings	$24.903	-$14.490	---
MWC JH- Implement RE Strategy	$6.837	-$2.797	-$0.238/-$0.236
MWC JV- Maintain IT Apps/Infra.	$0.850	-$0.850	-$0.119
Totals	**$32.590**	**-$18.137**	**-$357/-$355**

DRA proposes reductions of $18.137 million in PG&E's above-referenced expense forecasts. DRA relies on use of a five-year (2007-2012) average of data, escalated to 2014, to forecast MWC BI funding. DRA claims that historic

spending offers a reasonable forecast basis because the 2014 programs are not new, and nothing suggests that Corporate Real Estate faces challenges far more than in 2011. TURN proposes reductions of $0.357 million.

The elements of the PG&E 2014 capital forecast for Corporate Real Estate by MWC, together with DRA's and TURN's proposed reductions follows below:

($ in Millions)

Item Description	**Proposed Reductions**		
	PG&E Forecast	**DRA**	**TURN**
MWC 22-Maintain Buildings	$45.674	-$4.381	-$4.741
MWC 23- Implement RE Strategy	$35.378	-$25.330	-$21.358/-$19.051
MWC 2F Maintain IT Apps/Infra.	$0.550	-$0.550	-$0.077
Total	**$81.692**	**-$30.261**	**-$26.176/-$23.869**

DRA recommends reducing PG&E's Real Estate capital forecast by $30.261 million, or 37%, to $51.341 million. DRA accepts PG&E's 2012 recorded costs for MWC 22 but recommends use of a five-year average (2008-2012) to forecast 2013 and 2014 costs for MWC 22 and 23.

TURN proposes capital expenditure reductions of $26.2 million in 2014 based upon general differences in methodologies for forecasting construction unit costs and overheads, and based on rejection of specific proposals for relocation of service centers, as discussed below. Since TURN's disagreements relate to multiple MWCs, we address TURN's disputes first. We then proceed with discussion of specific MWC forecasts by project area.

7.6.2. Methodology Supporting Real Estate Forecasts (MWC 22, 23, JH, BI)

TURN takes issue with PG&E's methodology used to forecast Real Estate expenses and capital expenditures. PG&E utilized a variety of methods to

estimate its real estate program expenditures, which were also supported by training from the RS Means Company. PG&E obtained consultant or contractor estimates for all projects over $1 million. For projects under $1 million, PG&E's forecasts were based on unit costs and recorded costs for similar projects.

TURN proposes reductions to PG&E's forecasts based on differences relating to overhead cost adders and unit costs of construction. TURN proposes reductions of $26.176 million to PG&E's Real Estate forecasts in MWC 22, 23, JH, and BI, arguing that PG&E overstates overhead cost adders and unit costs of construction.

7.6.2.1. Overhead Cost Adders

PG&E's forecasts labor-related overhead costs, i.e., cost adders, for real estate projects as a percentage of base costs, including project and program management at 5% each and engineering, inspection, and testing, i.e., project engineering, ranging between 3% and 21.7%. TURN claims that a 10% combined project and program management adder, i.e., 5% + 5%, is excessive given that historical cost adder levels averaged less than 2% from 2009-2012. TURN claims that for program management, PG&E calculated a 4.25% cost adder for 2011 for projects over $1 million, and rounded up to 5%. For engineering costs, PG&E started with an estimated range of 6-13% for projects of more than $1 million, and 8-16% where the forecast is less than $500,000, and transformed that to a 10-15% adder. TURN claims that more appropriate cost adders are 1.7% for combined project and program management costs, and 1.5% for project engineering costs, based on its analysis of PG&E's recorded costs from 2009-2012. TURN recommends a 15% reduction to the otherwise adopted adders applied to Base and Seismic Building cost forecasts. PG&E relied on an analysis performed by Cushman & Wakefield to support its project management fees adder.

PG&E's and TURN's estimated cost adders are compared below:

	Forecast Percentage	
Component	**PG&E**	**TURN**
Project Management (consultant costs)	5%	1.7%
Program Management (PG&E labor costs)	5%	
Engineering, testing, inspection	3% - 21.7%	1.5%

PG&E claims that TURN excluded external project management costs and a portion of internal labor costs in calculating cost adders. By incorporating these additional costs, PG&E calculated recorded cost adders for 2009-2012 of approximately 3.8% for project management, 5.0% for program management, and averaging 6.3% for engineering costs. PG&E claims that TURN's sole reliance on historic costs ignores impacts of increases needed to improve aging facilities and yards. PG&E claims its forecasts rely on benchmarking data from university studies and RS Means Business Solutions. PG&E also denies that applying cost adders both for program and for project management constitutes double counting.

7.6.2.2. Construction Unit Costs

PG&E and TURN also disagree on unit costs relating to forecasted building construction. For Real Estate Solutions projects without detailed engineering design when the forecast was developed, PG&E relied on certain unit cost estimates applied to the square footage or other characteristics of each proposed project. These unit costs were based on data supplied by RS Means and adjusted for site-specific factors. TURN argues, however, that PG&E did not apply such an approach consistently. For a number of the unit costs that had the greatest bearing on a project's overall estimate, TURN claims that PG&E appears

to have developed generic unit costs with little if any grounding in the RS Means data, and made little if any adjustment of those unit costs for site-specific factors.

TURN proposes disallowance of PG&E's funding request for Real Estate Solutions projects, arguing that PG&E's forecasts rely on excessive unit cost assumptions. If the Commission grants funding for the projects, however, TURN proposes the use of lower unit cost assumptions. TURN's lower unit costs result in a 76% reduction to PG&E's forecasted real estate capital expenditures for real estate projects, and a 56% reduction to expense forecasts.

PG&E uses close to 20 different generic unit cost estimates to calculate various categories of corporate real estate project costs.[77] TURN proposes lower unit costs for most of these categories. TURN claims that PG&E's unit cost estimate of $560 per square foot (sf) for a new office building offers one of the best examples of inflated estimates, and that PG&E has not justified such a significant increase in unit costs in comparison to the 2011 GRC. TURN points to the example of the Merced Service Center, which, in the 2011 GRC, PG&E assigned a unit cost of $123/sf, based on 3% annual escalation. TURN proposes an alternative forecast using an estimate of $188/sf for a new office building, based on benchmark data from RS Means relating to new office and non-office construction.

PG&E claims its $560/sf estimate is justified based on a contractor's line-item estimate, and recorded costs for five completed projects. PG&E claims that TURN's estimated unit costs only include the basic shell office building, but

[77] PG&E-7, WP 6-890 - 6-964.

exclude the additional costs which PG&E included for a completed building project.

PG&E also criticized TURN's calculations for failure to reflect higher costs in California, or PG&E's use of higher-quality materials than U.S. government specifications, which affects the estimates. The RS Means $188/sf unit cost used by TURN is a national average. PG&E's estimate factors in costs not included in RS Means' estimate, such as site costs, furniture and building fixtures, IT, moving employees to the site, and soft costs (e.g., sales taxes, permit fees, environmental costs.

PG&E's estimates also incorporate a unit cost of $200/sf for new warehouse construction, while TURN, relying upon RS Means, estimates $83/sf. PG&E claims that TURN's $83/sf estimate must be adjusted to the PG&E area of operation. In addition, the RS Means estimate does not reflect architectural, engineering, furniture/fixtures/equipment, and other costs included in PG&E's $200/ft unit cost forecast.

For non-office construction, PG&E estimates a unit cost of $200/sf. While TURN estimates $66/sf. PG&E supported its estimate with costs from a recent service center construction project. TURN's recommendation is not based on industry data. TURN applied a fraction of its proposed unit cost for new office construction.

PG&E notes that RS Means disagrees with how TURN applied unit cost data. RS Means concluded that: "[TURN's] report is attempting to compare PG&E costs to [RS Means'] data . . . [and] demonstrates a misunderstanding of the basis of Means' data and how to use Means' data to compare the PG&E costs

that are cited."[78] TURN responds that several key elements of RS Means' critique of TURN's proposed unit costs apply equally to a number of PG&E's own unit cost forecasts.

PG&E's workpapers contain "local multipliers" that reflect cost variations throughout its service territory. PG&E also included the factors RS Means uses to make such adjustments for various local markets in PG&E's service territory, as a confidential exhibit. RS Means calculated a PG&E-specific "cost adjustment factor" in the range of 3-7% when it performed its construction cost analysis for PG&E in 2011. PG&E's unit cost estimate of $123/sf from the 2011 GRC (escalated to 2014 dollars) can be adjusted by applying both a local multiplier at the highest end of the 1.20-1.40 range and an additional PG&E-specific cost adjustment at the highest end of the 3-7% range. The resulting estimated unit cost for new office construction in 2014 would be approximately $200/sf, which is less than half of the $560/sf figure PG&E used.

TURN argues that PG&E's unit cost for non-office or warehouse construction costs are also overstated. PG&E used a unit cost of $200/sf, based largely on the estimated cost of constructing a "Generic Warehouse Building with Tenant Improvements for SF Greater Bay Area" of 35,000 square feet. TURN argues that none of PG&E's proposed real estate projects is a 35,000 square foot warehouse building in the San Francisco Bay Area. Instead, PG&E uses the $200/sf unit cost for non-office construction in Auburn, Fresno, Livermore, and Modesto. TURN questions why a $200/sf unit cost for the Bay Area should apply to projects in lower-cost areas. TURN believes such projects

[78] Ex. 60 (PG&E-22), Attachment 6F-2.

have more in common with replacement of warehouses or shops than with new construction, for which PG&E calculated replacement costs of $90.19/sf, and then adjusted by local multipliers.

TURN also recommends adjusting personnel IT costs downward to $4,903 per employee based on the cost for providing IT functionality in a mixture of new and existing office spaces. PG&E claims that this is not a reasonable comparison, and that it is inappropriate to apply assumptions representing a mix of new and existing facilities directly to a new construction project like the Alternate Emergency Operation Center.

PG&E claims the per-employee IT cost is much more expensive for new construction. In contrast to existing facilities, which already have IT infrastructure, PG&E is required to install that infrastructure in a new construction project. PG&E states that the Alternative Emergency Operations Center (AEOC) requires a different level of IT infrastructure than typical new construction office space, and that TURN's cost assumptions do not take account for the nature of the equipment needed for the AEOC which is a critical site for emergency operation that requires transmission systems with redundant paths to ensure seamless and reliable operations during an emergency.

7.6.2.3. Discussion

We conclude that, for the most part, PG&E's construction forecasts are based on reasonably supported unit cost assumptions. For example, PG&E's $560/sf estimate is supported by a general contractor and by recorded costs of similar furniture, fixtures, and equipment projects. C&W, one of the world's largest commercial real estate services firms, also supports PG&E's new office construction cost estimate.

We find insufficient basis to rely on TURN's alternative unit cost forecasts. We conclude, however, that it is appropriate to reduce PG&E's forecasts to reflect unit cost differences based on the localities where each building project is situated. In its Reply Brief, PG&E identified the effect on unit costs by recognizing local cost differences. Using the local multipliers ("City Cost Indices") received from RS Means,[79] PG&E adjusted the $560/sf unit cost estimate to reflect the local multiplier for each location where a proposed real estate project is planned. The specific unit costs are based on confidential information, but the average of these new estimates is $533/sf, which is 4.8% below PG&E's unit cost forecast of $560/sf.

PG&E made a similar calculation of adjusted unit cost for its proposed warehouse projects, on the same basis. The average of these new estimates is $189/sf, which is 5.5% below PG&E's forecast of $200/sf. We consider these two unit cost adjustments as calculated by PG&E to be representative of local multipliers applicable to the range of forecasted unit costs. Accordingly, as an approximation of the effect of applying local multipliers to all of PG&E's unit cost forecasts based on these two examples, we conclude that a 5% reduction to PG&E's capital cost forecast for Base Building and Seismic Safety projects is warranted. We thus apply a 5% reduction to PG&E's forecasts for MWCs 22, 23, JH, and BI.

We also reduce PG&E's forecasted overhead cost adders somewhat, but not to the extent proposed by TURN. PG&E's forecasted project management

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[79] The values for the "RS Means Location Cost Index" are found in confidential Exhibit 250C. The "Bay Area Cost Index," is the average of RS Means' City Cost Indices for nine Bay Area cities, also found in Exhibit 250C.

adder of 5% is slightly below benchmark data from RS Means and five universities, which indicated that an average cost adder was 5.04% for projects between $0.5 and $4.0 million, and 5.92% for projects less than $0.5 million. We are not persuaded that cost adders forecasted by PG&E, based on generic benchmarking, necessarily mirrors PG&E's requirements. We adopt forecasted cost adders that reflect recorded costs from 2009-2012, as recalculated by PG&E in rebuttal testimony, to include all relevant internal and external costs. These recalculated recorded cost adders relative to PG&E's forecasts is shown below:

Component	**PG&E Forecast**	**Recorded**
Project Management (consultant costs)	5%	3.8%
Program Management (PG&E labor costs)	5%	5%
Engineering, testing, inspection	3% - 21.7%	7.7%
Total	**18.2%**	**16.5%**

By applying cost adder percentages based on recorded data, we conclude that PG&E will be reasonably compensated for management and engineering costs. By basing forecasted adders on recorded data, we derive a total overhead adder of 16.5%, 1.7% lower than PG&E's forecasted 18.2%. Accordingly, we apply a reduction of 1.7% to PG&E's real estate forecast costs for MWC 22 and BI to reflect this lower overall overhead cost adder.

7.6.3. Base Building and Seismic Safety Programs (MWC BI and 22)

PG&E's Base Building Program maintains and extends the life of buildings and yards, corrects building deficiencies, improves equipment operating efficiencies, replaces obsolete components, and increases reliability. The Building Seismic Safety Program will complete seismic safety work at 16 buildings by 2016, non-structural seismic bracing upgrades at 77 Beale Street,

and seismic anchoring of emergency generator and computer equipment in the San Francisco Data Center. The ADA Compliance Program completes ADA accessibility improvements at Customer Service Offices as required by PG&E's Memorandum of Understanding with the Disability Rights Advocates.

DRA argues because maintenance is a regular recurring event that can be planned and managed, a five-year historic average offers a reasonable forecasting basis and reflects PG&E's actual decisions.

Discussion

We adopt 2014 expense funding of $23.234 million for MWC BI based on the following elements:

Item	($ in Millions)
Base Building	$14.803
Seismic Programs	$4.191
ADA Compliance	$5.909
Subtotal	$24.903
Less: 6.7% reduction in unit costs & adders	($1.669)
Adopted Total	$23.234

We apply a 6.7% reduction to our subtotal to reflect the reductions in unit costs (5%) and overhead adders (1.7%) as adopted above. Our adopted amount is more than DRA proposes but less than PG&E requests, and reflects a 2014 increase limited to the forecast increase between the 2012 and 2013. We recognize that historic spending is not the only basis to estimate prospective funding to maintain buildings. On the other hand, we are not convinced that the entire increase over historic spending requested by PG&E is warranted. As noted in reference to capital forecasts, we believe PG&E has some flexibility to defer some increases in its Base Building Program. To minimize the ratepayer

burden of cost increases adopted in this proceeding, our adopted reduction in PG&E's Base Building forecast is warranted.

We accept PG&E's proposed 2014 work scope for seismic safety and ADA compliance. We conclude that PG&E's seismic safety forecast addresses important safety risks, and implements the mandate of the California Seismic Safety Commission to have a program to manage earthquake risks with a dedicated staff and budget. PG&E's forecast is based on the work of a team of seismic experts hired to identify and design required structural improvements based on earthquake risk.

PG&E's proposed 2014 ADA Compliance Program addresses ADA compliance issues not addressed in prior GRCs. Following enactment of the ADA in 1992, PG&E completed barrier removal projects for ADA compliance in its buildings. However, ADA and Title 24 of the California Code of Regulations were updated in 2010. PG&E's original compliance efforts may no longer meet current ADA requirements.[80] PG&E's proposal is to assure ADA Title 1 (employee accessibility) and Title 3 (public accessibility) to all Corporate Real Estate managed buildings. This initiative includes ADA accessibility assessments at approximately 190 buildings to establish updated accessibility condition information, identify recommended accessibility improvements, and implement these recommendations.

For adopted capital expenditures to maintain buildings for MWC 22, we approve funding of $46.733 million for 2012, based on recorded costs, and $40.448 million for 2013, based on PG&E's forecast. For 2014, we adopt MWC 22

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[80] Ex. 30 (PG&E-7), at 6-56 to 6-57.

expenditures of $40.67 million, which is less than PG&E's forecast. PG&E's past spending deferrals indicate some flexibility and discretion in the pace of implementing building improvements. For example, in the 2011 GRC, PG&E was authorized $27.5 million for MWC BI, but cut program spending by $18.2 million, deferring projects for: (1) 77 Beale St./One Market Plaza; (2) Customer Office Refurbishment; (3) non-mandatory ADA surveys; and (4) Base Building maintenance (e.g., roof repairs, Heating, Ventilation and Air Conditioning repairs, carpet replacement, interior painting). The MWC 22/23 (previously MWC 78) budget for 2011 was decreased by $15.4 million from the 2011 GRC-imputed amount of $65.4 million. Also, MWC 22 (previously MWC 88) was decreased by $5.2 million from the GRC-imputed amount of $5.7 million to $0.5 million.

PG&E contemplates eliminating building condition deficiencies over six years starting in 2012.[81] Given this multi-year spending horizon, and given past spending patterns, we believe some flexibility exists to adjust pacing and allocation of MWC 22 funding as applied to 2014 revenue requirements. We thus derive the 2014 forecast in the following manner. We first take the average of the 2012 and 2013 forecast amounts (=[$46.733 + $40.488]/2) and further reduce this subtotal by 6.7%, to reflect the lower unit costs and overhead adders as we adopt above, for a final adopted forecast of $40.67 million. This adopted forecast is within the range of variation in recent years' spending patterns while trimming some from the large 2014 increases sought by PG&E. We believe that PG&E can

[81] PG&E's multi-year plans are detailed in the workpapers supporting Ex. (PG&E-7), beginning with WP 6-244.

reprioritize its spending plans to implement necessary improvements given these adopted 2014 funding levels, and deferring additional spending requirements to subsequent years.

7.6.4. Real Estate Planning and Transactions/Real Estate Solutions Programs (MWCs JH and 23)

PG&E forecasts capital expenditures in MWC 23 to refurbish or replace office and service center buildings to correct deficiencies, improve functionality, implement workplace improvements, and meet current business needs. PG&E's forecast includes seven office space projects, nine service center rebuilds, three service center consolidations, three 77 Beale Street refurbishment projects, and improving operating reliability of the Fairfield Data Center. PG&E's forecasts are based on site-specific analysis different from prior GRC forecasts. PG&E's 2014 capital expenditure forecast for MWC 23 consists of the following:

Element	**$Cost (in millions)**	
	Expense	Capital
Office Space Projects	$1.483	$8.719
Rebuild Service Centers	$0.292	$14.844
Relocate Service Centers	$0.051	$5.533
77 Beale St. Projects	$0.211	$1.049
Power Redundant Feed		$5.233
Total	**$2.037**	**$35.378**

PG&E also forecasts expense of $6.837 million in MWC JH for Real Estate Planning and Transactions and Real Estate Solutions Programs. PG&E plans to manage vacant properties and accelerate sale of real estate that is no longer needed. PG&E's forecasted expenses include $2 million in MWC JH to refurbish or replace office and service center buildings, to correct deficiencies, improve

functionality, and workplace conditions. The forecast is to secure office space to address high occupancy rates at many sites.

DRA does not challenge the merits of individual programs but proposes an overall reduction of $25.33 million to PG&E's MWC 23 forecast using a five-year historic average.

PG&E's MWC 23 forecast for Office Space Projects also includes funds to acquire additional office space where demand has exceeded supply, as summarized on Table 6-19 of PG&E's testimony (Ex. (PG&E-7)). PG&E plans to rebuild nine service centers during the 2014 GRC cycle, due to their age, condition, and functionality issues. PG&E's MWC 23 forecast includes its 77 Beale Street Building projects (1) for refurbishment of seven floors to improve the work environment and to correct interior condition deficiencies, (2) to relocate the Gas Control Center by the end of 2015, and (3) to restore the third floor use for group meetings.

PG&E's funding request also includes costs to close certain service centers and relocate their operations, as follows: (1) $55,000 expense and $6.2 million capital to consolidate Canyon Dam and Quincy Service Centers to a new location in Greenville; (2) $92,000 expense and $6.3 million capital to consolidate Clearlake and Lakeport service centers to a central location; and (3) $44,000 expense and $0.2 million capital to close Walnut Creek Service Center and relocate eight employees to the Concord Service Center. Four of the service centers in question (Quincy Dam, Quincy, Clearlake, and Lakeport) were constructed in 1960 or earlier. PG&E claims these service centers are no longer in the right location to best support current operations, and consolidating to a centralized location will enable more efficient operations.

TURN opposes the first two of these relocation projects, stating that PG&E has not justified them. TURN claims that PG&E did not demonstrate the necessity of acquiring five acre sites for the new service centers, the reasonableness of the per-acre prices, or explain why smaller acreage sites would not be sufficient.

The Greenville project costs are mainly for purchasing and preparing a five-acre site for the new service center ($3.574 million out of total costs of $6.165 million). The $2/sf land purchase cost estimate relies on an estimate from Cushman & Wakefield that translates to a price of approximately $95,000 per acre. The Clearlake project costs are mainly for purchasing and preparing a five-acre site for the new service center ($3.57 million out of total costs of $6.4 million). The $1.14/sf land purchase forecast relies on Cushman & Wakefield data equal to approximately $50,000 per acre.

TURN does not oppose closing Walnut Creek Service Center and relocating employees to Concord, but believes it should be funded with cost savings from abandoning the Walnut Creek facility. PG&E claims that TURN is double-counting its reductions. TURN assumes that PG&E will avoid future Base Building Program costs for the Walnut Creek Service Center, while it is also recommending reductions to the Company's Base Building Program forecasts.

Discussion

We adopt a 2014 capital forecast for MWC 23 of $12.840 million, determined as discussed herein.

We conclude that PG&E has generally justified the long-term benefits of undertaking most of the programs proposed for MWC 23. However, we conclude that PG&E has not adequately justified funding the proposed consolidations of the Canyon Dam and Quincy Service Centers to a new location

in Greenville ($55,000 expense and $6.2 million capital) and the Clearlake and Lakeport service centers to a central location ($92,000 expense; $6.3 million capital). We thus disapprove funding for both of these consolidation projects. In removing the Clearlake/Lakeport project, we reduce PG&E's 2014 forecast of $5.295 million in capital expenditures for MWC 23 and $7,000 in expenses for MWC JH.

The Lakeport and Clearlake service centers consolidation was scheduled to begin in the 2014 test year. This project has a $6.3 million capital forecast over three years beginning in 2014. The Canyon Dam and Quincy service center consolidation was not scheduled to begin until after 2014, however, and thus does not affect 2014 revenue requirements. Because the project could affect future revenue requirements, however, PG&E presented the forecast in this GRC.

We do not believe that PG&E has shown the necessity of acquiring five acre sites for these new service centers, or the reasonableness of the per-acre prices. PG&E did not explain why smaller acreage sites would not be sufficient. We also decline funding based on the conclusion that these consolidations are not of sufficient urgency to warrant approval at this time, particularly in view of other cost increases being imposed on ratepayers. Furthermore, PG&E postponed implementation of similar projects forecasted in the 2011 GRC based on its perception that other projects were of a higher priority.

We conclude that PG&E has justified funding for a new 12kV power feed from the Cordelia Substation to the Fairfield Data Center. We are not persuaded by DRA's recommendation of no funding because the Fairfield Data Center already has secondary power systems. DRA believes that funding the project is more of a question of convenience than need. PG&E upgraded the Fairfield Data Center in the period leading up to the 2011 rate cycle but did not see a need or

urgency to add the dedicated 12kV line. The new Sacramento Data Center provides added redundancy should a power failure occur at the Fairfield Data Center. PG&E also has a San Francisco Data Center that does the same. CAISO also maintains visibility with the same resources that the Data Centers monitor. CAISO does so at two locations in California for its own redundancy. PG&E also notes that the disruptions its proposed 12kV power feed is intended to eliminate are minimal at best.

We are concerned that DRA underestimates the potential seriousness of a business disruption caused by an outage at the Fairfield Data Center, which supports business critical IT processes including: (1) real-time monitoring and control of electric and gas operations; (2) emergency response processes; and (3) customer billing and payment. The Fairfield Data Center is currently supported by a single utility power line shared with many other customers. If the Data Center were to experience a catastrophic failure, critical information would be unavailable for at least 24 hours, and PG&E's Customer Call Center call routing systems would be inoperable. PG&E argues that it has been fortunate that power disruptions have not caused a catastrophic event, but that the risk of a costly failure continues with the passage of time. Reliance on back-up generators and batteries to support PG&E's electronic data is not a best practice.

The Fairfield facility will continue to be PG&E's primary data center for many IT systems through 2016, after which it will serve as the primary back up to PG&E's new Sacramento Data Center.

TURN argues that a portion of the Fairfield Data Center project includes FERC-jurisdictional costs that should not be included in this proceeding. PG&E adequately addressed this issue when its GRC application was filed. The

Fairfield Data Center project expenditures have been allocated to appropriate FERC accounts via Unbundled Cost Categories (UCC) in the Results of Operations (RO) model in this proceeding.

Therefore, we shall adopt the full amount requested by PG&E for Fairfield Data Center project, which is $5.233 million in 2014 capital expenditures under MWC 23, but with a reduction of 5% to reflect the lower unit cost assumptions adopted above. Thus, for the Fairfield Data Center project, we adopt $4.971 million in 2014 capital expenditures.

Additionally, we conclude that PG&E has generally justified the remaining programs. But the pace of program implementation should be adjusted to permit a more gradual ramp up in spending impacts. As discussed in reference to MWC 22, we believe that some flexibility and discretion exists in pacing the implementation of those programs. Particularly given the cumulative burden of cost increases imposed on customers, we believe it is appropriate to extend the implementation time frame to alleviate the impact on ratepayers in 2014. As previously noted, PG&E deferred implementation of similar programs under MWC 23 in the 2011 GRC based on an assessment of the relative urgency of programs, and in view of competing demands for spending.

Accordingly, we shall adopt a forecast that reflects a somewhat longer time frame for implementing the remaining programs forecast under MWC 23. Thus, we believe that PG&E can extend its implementation of the remaining planned projects over the three-year GRC cycle, consistent with its obligation to provide safe and reliable service. The capital forecast adopted shall be spread over the 2014-2016 period. The 2014 capital forecast shall then be 1/3 of the total capital forecast adopted. Based on this schedule of payments, PG&E would implement these programs over the 2014-2016 period. Incorporating a 5%

reduction to account for the lower unit cost assumptions, we adopt the 2014 capital forecasts for PG&E's remaining projects as calculated in the following manner:

	$ in Millions
PG&E's 2014 capital forecast	$35.378
Less: Fairfield Data Center Power Feed	($5.233)
Less: Clearlake/Lakeport project	($5.295)
Subtotal	$24.850
Less: 5% reduction for lower unit costs	($1.243)
Total capital forecast adopted for remaining projects	$23.608
2014 Capital Forecast for Remaining Projects (1/3 of the above Total Capital Forecast)	$7.869

Thus, the 2014 capital forecast for MWC 23 is $12.840 million, as calculated below:

Note: A 5% reduction (due to lower unit costs assumptions that was adopted earlier) were already applied to the following project costs	$ in Millions
Fairfield Data Center Power Feed	$4.971
Remaining Capital Projects	$7.869
2014 Capital Forecasts adopted for MWC 23	$12.840

We adopt a 2014 expense forecast for Real Estate Solutions Programs in MWC JH of $0.643 million, as calculated in the following manner. Since our adopted MWC 23 capital forecast is based on extending implementation over the three-year GRC cycle, we likewise adjust the MWC JH forecast for Real Estate Solutions Programs 2014 to reflect a three-year implementation timeframe. After disallowing $7,000 in expenses for the Lakeport/Clearlake project and applying a 5% reduction to reflect the lower unit cost assumptions adopted above, this subtotal shall then be divided by three to obtain the 2014 expense amount of

$0.643 of $2.03 million, since the implementation period has been spread over three years.

For PG&E's Real Estate Planning and Transactions Program, we adopt PG&E's 2014 forecast of $4.8 million in MWC JH without change. Since activities under this program are based on longer-term planning functions that are less dependent of the specific timing of building acquisitions or replacements, we do not pro-rate the forecast for this program as for the Real Estate Solutions Program costs.

7.6.5. MWC JV – IT Applications and Infrastructure

MWC JV is the IT Applications and Infrastructure component of PG&E's Base Building and Real Estate Planning and Transaction Program. PG&E forecasts $0.850 million in expenses under MWC JV for 2014, consisting of $0.65 million for the Base Building Program and $0.2 million for the Real Estate Planning and Transactions program.

DRA opposes PG&E's $0.850 million forecast in MWC JV for three IT initiatives to update legacy computer systems. PG&E received funding for a similar program initiative in 2011 but did not implement the initiative. PG&E's March 2012 Budget Report shows $608,000 left in its 2011 budget for the Base Building Program. DRA argues that ratepayers should not pay for these projects until funds provided in the 2011 GRC have been used.

PG&E claims that DRA mischaracterizes the results of the 2011 GRC.

PG&E argues that reliance on past spending averages does not reflect industry and building conditions, legal requirements, or other relevant factors. PG&E claims that 2011 GRC revenues were insufficient to support all of the 2014 forecasted work.

The IT projects are to integrate a stand-alone legacy computer system with PG&E's enterprise project management and content management systems. The first IT project is to replace a project management system that is not integrated with the SAP system. As a result, cost information must be manually extracted from SAP. The second IT project is to improve records management by digitizing physical documents and to provide CRE-specific indexing and classification identifiers. Because of the age of the current systems, key functionalities are unavailable for effective and efficient records management. The IT project will integrate a stand-alone workspace management system with the IT enterprise infrastructure and increase operating reliability and data security.

Discussion

We adopt funding the expenses for the IT Applications and Infrastructure component of PG&E's Base Building and Real Estate Planning and Transaction Program under MWC JV, but reduce PG&E's forecast by 14% to apply DRA's global adjustment based on use of PG&E's Concept Cost Estimating Tool. Thus, we adopt $731,000 in expenses under MWC JV. As noted by DRA, PG&E chose not to spend previously approved funds for the purpose of implementing a similar system in 2011. While we share DRA's general concern regarding PG&E's request for ratepayer funding on a repeated basis for the same programs, we believe that in view of the benefits offered, some funding of the IT applications is warranted in this instance. Our adoption of the 14% reduction in PG&E's adopted forecast, however, provides some recognition of DRA's concerns and mitigates ratepayer risk that PG&E may postpone implementing these IT programs.

7.7. Environmental Program

The Environmental Program (Environmental) is responsible for compliance with environmental laws and for establishing policies and programs aimed at reducing PG&E's operational footprint and managing its business in an environmentally sustainable way.

7.7.1. Environmental Program Expenses

PG&E's 2014 Environmental Program expense forecast of $31.736 million is summarized on Table 7-23 of PG&E's Opening Brief. Drivers of PG&E's expense forecast are related to: (1) managing day-to-day environmental activities, including costs of professionals to perform compliance tasks; (2) implementing a Land Stewardship Program; and (3) implementing an EHS Compliance Management System.

DRA and TURN accept the majority of PG&E's expense forecast for Environmental Programs. DRA, however, opposes the Land Stewardship Program and two IT-related initiatives to implement an EHS system and an electronic document management system. In MWC AK, PG&E accepts DRA's recommended $5.002 million reduction. PG&E cedes its request for reimbursement of CARB Cost of Implementation Fee costs, legally mandated by AB 32, because the Commission has determined that these costs are reimbursable as part of another Commission proceeding. In MWC ES, PG&E does not dispute DRA's recommended $0.023 million reduction. We adopt PG&E's forecasts for the Environmental Program for all of the MWCs for which no disputes exist. We address the disputed issues related to PG&E's Environmental Program below.

7.7.1.1. MWC JE: Land Stewardship Management Program

PG&E forecasts $3.34 million in MWC JE for expenses associated with Land Services, including various land management and land rights support activities. PG&E includes funding to establish a Land Stewardship Management Program to permit more proactive management of its properties, with both environmental stewardship and public safety as top priorities.

DRA opposes funding the Land Stewardship Management Program, resulting in a $1.2 million proposed reduction in PG&E's forecast for MWC JE. DRA argues that PG&E already has a duty to inspect and manage its properties.

PG&E responds that proactive land management is necessary to mitigate the risks of injuries, property damage, and disruption to operations. PG&E owns and manages a portfolio of properties located throughout its service territory, including land owned in fee, and land upon which PG&E holds an easement. PG&E has a duty to conserve and protect these lands, which includes approximately 140,000 acres of watershed lands in the Sierra Nevada and Cascade Mountains and 655 acres in the Carizzo Plains as part of PG&E's Land Conservation Commitment with the CPUC resulting from PG&E's bankruptcy settlement.

Discussion

We adopt PG&E's forecast of $3.34 million in MWC JE for expenses associated with Land Services including funding to establish a Land Stewardship Management Program. We conclude that PG&E has adequately justified the benefits and merits of the Land Stewardship Management Program, including the long-term cost reduction of habitat and species mitigation requirements by using PG&E-owned lands to offset impacts of PG&E or third-party projects. Other non-quantified benefits include habitat enhancements and improved

community and regulatory agency relations. We conclude the overall benefits justify approval of the $3.34 million in forecast expenses for MWC JE.

7.7.1.2. MWC JV: Environmental Health and Safety (EHS) Compliance Management

PG&E forecasts $4.4 million in 2014 for MWC JV for environmental programs. PG&E proposes an IT system to assist in managing environmental commitments and risks. The principal new programs covered under MWC JV are the EHS and the Enterprise Content Management System.

The EHS Compliance Management System will transition multiple workflow processes into a single data system for measuring, managing, tracking, and reporting on environmental commitments.

DRA recommends reductions of $3.3 million to MWC JV, reflecting no funding for PG&E's Environmental Health and Safety Management System ($2.8 million) and Enterprise Content Management System ($0.5 million). DRA and TURN also propose a 14% reduction to the forecast for project forecasts developed using PG&E's Concept Estimating Tool, which PG&E opposes.

DRA opposes funding for the EHS System, stating that the costs seem excessive to achieve cost avoidance, and that PG&E cannot quantify the avoided costs. PG&E claims that DRA considers solely the savings expected at the initiation of a project, but does not acknowledge the risk mitigation benefits of the System. PG&E claims that minimizing the risk of fines and penalties for noncompliance with environmental regulations justifies adopting the EHS System, without reduction. PG&E has been fined for non-compliance with environmental laws and regulations.

PG&E also proposes funding of $0.5 million for an Enterprise Content Management System that will migrate existing environmental and land

documents to PG&E's IT platform, providing index and classification identifiers to improve document retrieval and electronically linking environmental and land records with operating assets. DRA argues that the costs of the program are excessive in relation to the non-cost benefits that are claimed.

Discussion

We adopt PG&E's forecast for MWC JV, except for a 14% reduction as proposed by DRA for forecasts developed using PG&E's Concept Estimating Tool. In all other respects, we conclude that PG&E adequately justified its forecast, including funding for the EHS system and the Enterprise Content Management System.

The EHS system provides non-cost benefits of improved workflow and integration with other corporate management systems, as well as the opportunity to implement environmental best practices and corrective actions across different LOBs. The current compliance system is10 years old and can only track compliance at certain facilities and remediation sites. The current system is inadequate to manage the complexity of current regulations, and is not designed to manage environmental compliance efforts related to field activities.

Under the Enterprise Content Management System, more than 800,000 physical documents and records will be digitized and linked to specific operating assets using common nomenclature. As a result, employees will be able to retrieve key documents relating to operating assets and identify relevant land rights and environmental restrictions associated with those assets.

Although it is difficult to assign a dollar value to all of the non-quantified benefits expected from these programs, we conclude that our adopted forecast of costs for these programs is reasonable in relation to the overall benefits that are expected, as summarized above.

7.7.2. Environmental Program Capital Expenditures

PG&E's forecast for Environmental Program capital in 2014 is $11.526 million, which includes costs for the development of Habitat Conservation Plans, underground storage tank removal, several IT initiatives, and tools and equipment.

DRA opposes funding for the underground storage tank removal in MWC 12, and an EHS system and Electronic Content Management System in MWC 2F. We adopt capital expenditure forecasts for the EHS System and Electronic Content Management System consistent with our discussion of these programs expense components, as discussed above. Accordingly, we adopt PG&E's forecasts for these items, reduced by 14% to reflect adoption of DRA's adjustment for use of the Concept Estimating Tool.

We adopt PG&E's Environmental Program capital expenditure forecasts for the uncontested amounts set forth in MWC 05, 12, and 2F, as summarized on page 7-60 of PG&E's Opening Brief. We address the disputed items below.

7.7.2.1. MWC 12: Environmental Capital

PG&E's forecast of environmental capital costs in MWC 12 includes funds for development of additional Habitat Conservation Plans (HCPs) and the removal of underground and above-ground fuel storage tanks. PG&E and DRA present different capital expenditure forecasts for MWC 12, as set forth below:

($ in Millions)

	2012	2013	2014
PG&E	$4.941	$6.330	$6.956
DRA	$3.226	$4.330	$4.956

DRA proposes a lower 2012 expenditure level based on PG&E's recorded 2012 costs. DRA recommends lower expenditures for 2013 and 2014 based on exclusion of funding for PG&E's storage tank removal program. DRA accepts PG&E's capital forecasts for 2013 and 2014, except for opposition to funding for the underground storage tank removal project (at $2 million per year). DRA opposes funding on the basis that PG&E received funding for this program in the 2011 GRC. DRA argues that ratepayers should not pay again for this program as the costs are embedded in PG&E's revenue requirements.

PG&E claims that DRA is incorrect and that PG&E did not receive funding for this activity in the 2011 GRC.

Discussion

We adopt DRA's forecast of capital expenditures for MWC 12 for 2012 since actual costs provide a more accurate forecast basis. We adopt PG&E's forecast, however, for 2013 and 2014. The only disputed item is funding of the tank removal program.

Leaking tanks create environmental and public safety hazards by contaminating soil and groundwater. The cost of remediating the soil and groundwater is significantly higher than the cost of removing the tanks as they near the end of their useful life and are still operational. The majority of PG&E's underground storage tanks were installed in the early 1990s. Generally, these tanks have a 20-year useful life, at which point it is expected that they will deteriorate and eventually leak. PG&E's proposed program to remove the tanks can reduce the potential for leakage.

DRA does not dispute the benefits of the tank removal program, but objects to ratepayer funding based on concerns that ratepayers should not pay for the same program twice. We recognize that PG&E received funding in the

2011 GRC based on PG&E's forecast for underground tank removal similar to what is proposed for this GRC cycle. Given the specific facts at issue here, however, we conclude that PG&E is reasonably entitled to funding for the underground tank removal program.

PG&E performs tank removals as business needs allow and dictate. PG&E's previous deferral of the tank removals was not discretionary, but was based upon factors beyond its reasonable control. These factors included lack of proximity to alternative fueling sites, need for access to fuel during power outages, and the need for wide access for fueling large service vehicles. As a result, implementation of the tank removals was infeasible. Given the specific circumstances involved here, we conclude that PG&E's request for additional funding for the tank removal program should not be denied merely because of factors beyond its control. Accordingly, given these considerations, we approve PG&E's capital forecasts for MWC 12 for 2013 and 2014.

7.8. Enterprise-Wide IT Costs

PG&E projects 2014 expenses of $261.6 million in MWC JV for enterprise-wide IT projects and programs, shown in Table 7-25 of its Opening Brief, representing a 20.6% increase over 2011 recorded expenses of $217.0 million. PG&E also forecasts $136.3 million in 2012, $142.7 million in 2013, $209.6 million in 2014, $209.7 million in 2015, and $196.7 million in MWC 2F for capital expenditures associated with seven enterprise-wide IT initiatives, seen in

Table -26 of PG&E's Opening Brief.[82] Key cost drivers of PG&E's expense forecast are escalation for maintenance contracts and licensing plus increased headcount to support increases in IT devices, systems, and applications deployed, while key drivers of PG&E's capital forecast include adding three new asset classes to the Lifecycle program and implementing three Technology Reliability projects and two Continuous Improvement projects. Enterprise-wide IT projects and programs consist of: (1) a Baseline Portfolio, which includes ongoing O&M for IT systems, applications, and infrastructure; and (2) a Technology Reliability Portfolio, which includes capital and expense proposals covering the repair and replacement of physical IT assets along with enterprise-wide technology projects.

7.8.1. Baseline Portfolio

PG&E forecasts a 2014 Baseline Portfolio of $240.9 million. Baseline operations provide for ongoing O&M of technology systems and infrastructure to maintain "status quo" operations in all line of business. Cost drivers include: application license fees; enterprise application support and vendor service agreements; increased labor costs related to a reallocation of IT resources in order to provide more effective business technology project implementation and support; and new employees to support growth of IT.

DRA proposes funding of $221.2 million for 2014 Baseline expenses, a reduction of $19.7 million. DRA bases its recommendation on a trend analysis of

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[82] Separate from PG&E's "enterprise-wide" information technology expense and capital forecasts discussed here, other IT projects are addressed in sections of this decision relating to PG&E's respective lines of business.

recorded Baseline expenses from 2008 to 2012, escalated to derive its 2014 recommended funding level. PG&E claims that DRA does not consider incremental changes driving Baseline expense forecasts such as: third-party network leased lines fees; application license fees; and increases in enterprise application support and vendor service agreements for new technology. PG&E forecasts a 120% expense increase and an 85% capital increase in IT spending between 2012 and 2014 for new applications.

TURN proposes a reduction of $6.3 million to PG&E's Baseline Portfolio forecast. TURN recommends a 25% reduction to PG&E's IT project forecasts across all LOBs and then applies this same 25% reduction to PG&E's Baseline forecast to reflect the reduced need for IT operations and maintenance support.

Discussion

We adopt PG&E's forecast of $240.9 million for Baseline operations for ongoing maintenance of IT systems and infrastructure. PG&E reasonably identified the cost drivers of the forecast including application license fees; enterprise application support and vendor service agreements; increased labor costs related to reallocation of IT resources; and additional employees to support growth of IT across the LOBs.[83]

We decline to adopt DRA's proposed reduction of $19.7 million in PG&E's forecast of Baseline expenses based on recorded Baseline expenses from 2008 to 2012. DRA's analysis does not consider the factors driving the increases in the Baseline expense forecast amounts, as noted above.

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[83] Exh. 30 (PG&E-7) at 8-35, lines 7-30.

We also decline to adopt TURN's proposed reduction of $6.3 million for similar reasons. TURN recommends a 25% reduction to PG&E's IT project forecast across all LOBs and then applies this same 25% reduction to PG&E's Baseline forecast to reflect the reduced need for IT operations and maintenance support. PG&E claims that its LOB forecasts include technology projects that are essential to improve public and employee safety, maintain system reliability, and mitigate enterprise and operational risks.

7.8.2. Technology Reliability Portfolio

7.8.2.1. Lifecycle Initiatives

Lifecycle initiatives are programs for the replacement and upgrade of PG&E's IT assets. The costs recorded to Lifecycle include amounts for purchasing replacement equipment and the labor required to remove the existing asset and install the new equipment. Lifecycle cost increases are driven by the continuing growth of PG&E's IT asset base and new asset classes—software applications, SmartMeter™ network components, and cybersecurity assets—that have been added to the Lifecycle portfolio for the first time in this GRC. PG&E's 2014 expense forecast for Lifecycle initiatives recorded in MWC JV is $8.7 million.

DRA proposes a 2014 Lifecycle expense funding level of $4.0 million, a reduction of $4.7 million. DRA bases its recommendation on a five-year average of PG&E's recorded Lifecycle expenses, from 2008 to 2012.

PG&E forecasts Lifecycle capital expenses of $102.9 million in 2014, $101.4 million in 2015, and $119.3 million in 2016 in MWC 2F. PG&E originally sought Lifecycle capital expenditures in the amount of $105.7 million in 2014, $104.1 million in 2015, and $122.0 million in 2016. PG&E has agreed, however, in response to a recommendation made by TURN, to reduce its Lifecycle capital

expenditures forecast by $2.7 million each year from 2014 to 2016, through concessions. With PG&E's concession, no party disputes PG&E's adjusted capital forecast for IT Lifecycle work in 2014, 2015, and 2016.

Discussion

We adopt PG&E's forecast for Lifecycle expenses. We conclude that use of a five-year historic average does not adequately reflect the changed conditions during 2014 that require a greater scope of activity and related spending. As noted by PG&E, these factors include the continued growth of PG&E's asset base; the addition of three new asset classes to the Lifecycle portfolio; the relationship between capital and expense amounts; and additional funding needed to upgrade and replace IT asset funded in prior rate cases. Lifecycle efforts are critical for maintaining the health of the IT asset base and to avoid the risk of unacceptable failure if infrastructure equipment is not maintained.[84] We conclude that the adopted funding is warranted in the interests of safe and reliable service.

7.8.2.2. Disaster Recovery

PG&E is forecasting capital costs of $33.9 million in 2014, $44.0 million in 2015, $18.7 million in 2016, and $3.1 million in 2014 expenses for Disaster Recovery to reduce IT and cybersecurity risks. PG&E's Disaster Recovery project will: (1) develop and implement a robust, enterprise-wide IT disaster recovery program that focuses on PG&E's mission critical safety, reliability, and operating processes; (2) address LOB requirements for ensuring the availability of mission critical business processes; (3) provide additional security and redundancy for

[84] Exh. 30 (PG&E-7) at 8-13, lines 27-29.

essential systems and applications; and (4) apply industry best practices for disaster recovery programs and IT data centers.

DRA does not address Disaster Recovery. TURN recommends reducing PG&E's Disaster Recovery project forecast by half, thereby disallowing $1.6 million in expense in 2014 and capital expenditures of $18.5 million in 2014, $22.0 million in 2015, and $9.4 million in 2016. TURN argues that there is no benefit/cost analysis to justify this system or detailed documentation for the $96.6 million project costs. TURN believes that the number of processes PG&E classifies as mission critical is too extensive to implement them all in this GRC cycle.

PG&E identified a list of 17 mission critical processes as the focus of the Disaster Recovery project, and ranked in order of criticality. The first eight processes deal with operations and safety in a way that the utility claims cannot tolerate down time. The processes ranked 9 through 17 can tolerate down time from four hours to 30 days.

TURN argues that only the more critical safety processes, such as processes 1 through 8, should be part of this project now, but that any future re-architecting of processes for Disaster Recovery should occur at the time of lifecycle replacement to further minimize costs.

PG&E claims it will achieve certain cost efficiencies by implementing all 17 mission-critical business processes concurrently. PG&E organized and trained a Disaster Recovery implementation team for this project. PG&E claims that if it implements only one half of the processes now, it will lose the efficiencies, specialized skills, and knowledge gained by the same team working together applying lessons learned from one process to the next. Transitioning to a new team will be less efficient and will result in higher project costs.

PG&E claims that TURN focuses on financial benefits, while ignoring the safety and reliability benefits. PG&E acknowledges that the project is not intended to generate significant cost savings.

TURN identified one software application that it claimed is not mission critical because it allows customers to view their energy usage, view real-time outages, pay their bill and connect or disconnect their service. PG&E claims that TURN's focus on this single application fails to address how the processes impact public and employee safety and system reliability as well as customer, regulatory, financial, and reputational conditions.

Discussion

We adopt PG&E's forecast of $33.9 million in 2014, $44.0 million in 2015, $18.7 million in 2016, and $3.1 million in 2014 expenses for Disaster Recovery to reduce IT and cybersecurity risks. We are not persuaded by TURN that reducing the project forecast by one-half would be serve ratepayers' best interests in the long run. TURN's proposal would reduce the current revenue requirement, but would also eliminate potential benefits relating to the second half of PG&E's Disaster Recovery Program. Although PG&E has not quantified the total benefits in relation to costs, based on the record before us, we conclude that funding the 17 projects identified by PG&E is justified. We are persuaded that PG&E utilized a rigorous evaluation, working with outside experts to identify and prioritize the 17 most mission-critical business processes that impact public and employee safety, system reliability, customer, regulatory, financial, and reputational conditions. Postponing half of the programs to the next GRC cycle would not be an efficient use of funding in the long run.

7.8.2.3. Telecommunications Network Enhancement

PG&E forecasts capital costs of $39.4 million in 2014, $30.9 million in 2015, $30.1 million in 2016, and $3.5 million in 2014 expenses for its Telecommunications Network Enhancement project. PG&E seeks to enhance its current network technology capabilities by building a telecommunications infrastructure to: (1) support existing and planned future applications and services; (2) simplify the integration of devices and applications into the network; and (3) streamline overall telecommunications network operations. PG&E claims that an enhanced telecommunications network is needed due to the growth in electric grid and gas automation and control, customer service programs, cybersecurity, information management, and enterprise wide technology initiatives.

DRA accepts PG&E's $3.5 million 2014 expense forecast but recommends normalizing capital costs, resulting in a 2014 funding level of $13.1 million. The effect of normalizing the 2014 capital forecast – dividing the 2014 forecast amount equally among 2012, 2013, and 2014 – is a 67% ($26.3 million) reduction. PG&E argues that this reduction is unsupported by analysis of the merits of the project. PG&E did not spend money on Telecommunications Network Enhancements in 2012 and does not anticipate spending any in 2013. PG&E's planned start date for the project was January 2014. PG&E argues it is unfair to retroactively assign funding to a project when no work was done.

TURN supports DRA's proposed normalizing of PG&E's 2014, 2015, and 2016 capital forecasts and further reducing the resulting amounts by 30%, for recommended capital forecast reductions of $16.4 million in 2014, $7.9 million in 2015, and $7.1 million in 2016, as well as disallowance of $1.1 million in expense in 2014. PG&E disagrees with TURN's recommended reductions.

TURN argues that PG&E's expectation of 300% growth in bandwidth requirements over the next five to10 years is overstated due to exaggerated planning for growth in Plug-In Hybrid Electric Vehicles (PHEV) and an excessive number of future workers with mobile capability. Based on TURN's analysis, which reduced the expected bandwidth for both mobile workers and PHEVs, only 70% of PG&E's requested amount could be justified in the next five to 10 years.

PG&E argues that reducing funding as proposed by TURN would not leave sufficient funds to construct the telecommunications networks.

Discussion

We approve PG&E's 2014 forecast of capital expenditures and expenses for the Telecommunications Network Enhancement project. We conclude that PG&E has justified the project in view of the projected increase in network bandwidth needs and has identified the principal factors that support its forecasted cost increases. We conclude that fixed network costs (e.g., geographic network reach to substations, generation and distribution sites, and installing network monitoring and cybersecurity devices) are the most significant project cost drivers. We find no basis to adopt a reduction of the forecast by normalizing expenditures in the manner proposed by DRA. We also find no basis, to reduce the forecast based on TURN's analysis that the number of PHEVs is a significant cost driver. As noted by PG&E, changing that assumption will not significantly reduce the costs of the telecommunications network. TURN also argues that the number of future PG&E workers with mobile capability is excessive and recommends that each work crew have only one mobile device.

We agree that it is reasonable to limit each work crew to one device. TURN adjusts PG&E's estimate of an additional 1000 mobile workers down to an

additional 400, thereby reducing future core bandwidth needs for mobile workers by 60%. Considering reduced bandwidth needs, a limited reduction of 15%, which is half of the reduction proposed by TURN, is justified. For PG&E's Telecommunications Network Enhancement, 2014 expense is thus reduced by $525,000 and capital expenditures are reduced by $5.9 million.[85]

7.8.2.4. Identity and Access Management

PG&E forecasts capital costs of $6.1 million in 2012, $9.5 million in 2013, $10.0 million in 2014, $9.0 million in 2015, and $8.0 million in 2016 for its Identity and Access Management (IAM) project. PG&E argues that the IAM is a key component of cybersecurity risk management and will protect PG&E's electronic data and physical assets by providing access to information and facilities only to authorized individuals. IAM was implemented to comply with recently enacted NERC CIP (North American Electric Reliability Corporation Critical Infrastructure Protection) regulations and to address information security risks.

DRA and TURN each recommend a reduction of 14% to PG&E's capital forecasts for IAM because PG&E developed the forecast using its Concept Cost Estimating Tool.

Discussion

We adopt PG&E's IAM capital forecast, but reduced to reflect adoption of DRA's proposed 14% reduction for use of the Concept Cost Estimating Tool. We conclude that the IAM project will protect PG&E's electronic data and physical assets by providing access to information and facilities only to authorized

[85] See Exh. 32 (PG&E-7), WP 07-09, p. 8-174, as the basis for the adjustment.

individuals. IAM was implemented to comply with recently enacted (NERC CIP) regulations and to address information security risks.

7.8.2.5. Records Management Archival

PG&E forecasts capital costs of $16.5 million in 2014, $17.6 million in 2015, and $10.4 million in 2016, and $4.1 million in 2014 expenses for its Records Management Archival project. This project will build on the existing records management system by providing additional tools and capabilities to address changing records management needs and to implement new policies and standards. Records Management Archival will incorporate: (1) a records management environment that is scalable and can grow to handle the increasing volume of records produced by the business; and (2) improvements to records search and retrieval plus the ability to handle new kinds of records such as engineering drawings, digital assets, and video.

DRA opposes ratepayer funding for Records Management Archival until PG&E has demonstrated that its 2011 GRC funding for an enterprise-wide data archival and records management program is operational. DRA also questions why PG&E proceeded with the 2011 GRC funded project knowing that it did not offer all the functionality PG&E required.

TURN recommends no funding for this project, stating that PG&E should fund it out of the document storage cost savings achieved in this rate case cycle. TURN criticizes PG&E for not attributing cost reduction benefits to this project.

PG&E contends that it does attribute cost reduction benefits to Records Management Archival, but cannot quantify them until after the project is implemented. PG&E anticipates that once all systems are implemented and data archival begins in 2017, unit costs for storing and backing up electronic records will be less than half of what they are today.

PG&E claims that it cannot use these cost savings generated during this rate case cycle to build Records Management Archival because the project will not generate savings until after it is built. PG&E will begin incurring project costs in January 2014 and does not expect to generate savings until the project is implemented and data archival begins in 2017.

Discussion

We adopt PG&E's forecast of capital costs and expenses for its Records Management Archival project. In the 2011 GRC, PG&E requested funding to build a records management system using a tool called Documentum which is the foundation for the records management archival program forecasted in this GRC. PG&E plans to add tools and capabilities onto the existing Documentum platform to address changing needs. We recognize that PG&E's records management needs have increased and implementing the additional functionality forecasted in this rate case is warranted. Since PG&E will not generate project savings until the project is implemented in the next GRC cycle, we do not adopt TURN's recommendation to fund current project costs out of future cost savings. We expect PG&E to identify the applicable ratepayer savings in the next GRC cycle.

7.8.2.6. Service Management

PG&E forecasts capital costs of $5.3 million in 2013, $6.9 million in 2014, and $1.0 million in 2014 expenses for its Service Management project. PG&E's IT organization will purchase a set of advanced, proactive monitoring tools and implement new processes that will enable real time visibility into each component of the IT environment. We conclude that the expected benefits justify the funding of 2013 and 2014 capital. We express no opinion on PG&E's 2015 and 2016 forecasts, but separately address attrition ratemaking in Section 12.

DRA recommends no funding for this project, arguing that continual improvement should be implicit in PG&E's management activities and ratepayers should not have to fund specific projects to gain improvements.

PG&E argues that the continuous improvement activities that are part of IT's routine operations is different from the fundamental change to IT that the Service Management project represents.

PG&E forecasts $26 million in capital over four years to fund the Service Management Software System, which will use automation to reduce operational per unit IT costs by 20% in order to help offset cost escalation. TURN claims, however, that PG&E is already exceeding many of the cost reduction goals and thus achieving savings without the requested new software. TURN argues that there is not convincing evidence of sufficient benefits to warrant the expenditure of $26 million. TURN thus recommends re-scoping the project so that the costs are more in-line with the potential benefits. TURN recommends $3 million for a smaller project to monitor IT health through disallowing capital amounts of $4.3 million in 2013, $5.9 million in 2014, $5.8 million in 2015, and $7.4 million in 2016.

PG&E claims that Service Management is more than a project for tracking common IT and industry measures regarding IT downtime and cost to repair IT incidents. Rather, PG&E argues that the goal of Service Management is to develop and employ metrics that measure the impact of IT reliability on PG&E's LOBs.

Discussion

We approve PG&E's forecasts for capital costs of $5.3 million in 2013, $6.9 million in 2014, $6.9 million in 2015, and $7.4 million in 2016, and $1.0 million in 2014 expenses for its Service Management project. We recognize

that PG&E's IT systems are more complex today, and the Service Management improvement initiative will help to ensure the reliability and efficiency of its IT environment.

7.8.2.7. Forecasting Methodologies Based on PG&E's Concept Cost Estimating Tool

As in the 2011 GRC, PG&E used the Concept Cost Estimating Tool to prepare forecasts for most of the enterprise-wide and LOB software application development projects proposed for this GRC. PG&E uses the Concept Estimating Tool to generate initial forecasts of software application development projects early in the project lifecycle. PG&E has used the Concept Cost Estimating Tool since 2008 to generate initial cost estimates for software application development projects.

DRA argues that there are uncertainties as to whether the IT projects that PG&E forecasts in this GRC will be completed. DRA believes that PG&E's use of the Concept Cost Estimating Tool for IT project forecasting results in significant forecasting difficulties. DRA found that PG&E only spent 86% of its 2011 GRC funding for IT projects as compared to forecasted amounts derived using PG&E's Concept Estimating Tool. Therefore, DRA believes that it is reasonable to impute a similar potential forecast variance for IT projects proposed in the 2014 GRC that are derived using the Concept Cost Estimating Tool. DRA's assumed level of 2014 spending for these IT projects thus results in its proposed reduction of 14%. TURN agrees with DRA.

PG&E disputes DRA's recommended 14% reduction to its IT project forecasts derived from the Concept Cost Estimating Tool, claiming that DRA's methodology for calculating the disallowance is flawed. PG&E claims that the Concept Cost Estimating Tool has proven to be accurate, with recorded projects

costs within 99% of the amount forecasted using the tool. PG&E claims that DRA's calculations of a 14% forecast error is based on a faulty analysis, as it: (1) uses data from a single period that does not account for costs for incomplete, multi-year projects; (2) includes cancelled projects; and (3) includes projects deferred to the 2014 GRC.

DRA's analysis only includes project costs from 2010 through 2012 while excluding recognition of 2013 project costs. However, 21 of the 38 projects forecast in the 2011 GRC are still in development and PG&E expected to spend 2011 GRC funding on them during 2013. Because the projected 2013 spending was not included in DRA's analysis even though 2013 forecasted amounts are included, PG&E argues that DRA inflates one side of the equation.

Second, DRA includes the forecasted amounts for cancelled projects in its analysis, but because there are no recorded costs, as the projects were cancelled, PG&E claims that one side of the equation is inflated.

Third, DRA includes forecasted amounts for projects that were deferred to the 2014 GRC in its analysis, but because there are no recorded costs, as the projects were deferred, PG&E again claims DRA inflates one side of the equation. PG&E presented a table showing the effects on the calculation of forecasted to actual variance based on each of the adjustments PG&E claims are appropriate. (*See* Ex. 60, at 8-41).

Based on its recalculation, PG&E claims that it is unreasonable to fund only 86% of PG&E's forecasts when PG&E actually spent 99% of the amount it estimated for projects whose forecasts were generated by the Concept Cost Estimating Tool.

DRA does not recommend an alternative estimating methodology for IT costs. PG&E claims that its use of the Concept Cost Estimating Tool, along with

professional judgment and experience, is a reasonable and sound approach for forecasting IT project costs early in the project lifecycle. PG&E claims this forecasting method is consistent with standard industry best practices and consistent with the practices outlined by Gartner, a leading technology and advisory company.

Discussion

We address the empirical accuracy of the forecast variance as calculated by DRA, as well as the conceptual merits of relying on forecast variances from the prior GRC cycle as a consideration in setting prospective forecasts.

Contrary to PG&E's objections, we conclude that DRA's calculation of a 14% variance provides a reasonable representation of the variance between forecasted and actual costs relating to PG&E's use of the Concept Cost Estimating Tool. We do not accept PG&E's claim that the Concept Cost Estimating Tool resulted in forecasting accuracy of 99%.

We agree with PG&E that a fair analysis of the accuracy of the Concept Cost Estimating Tool requires that forecast data be compared with recorded cost data on a consistent basis. We do not accept PG&E's claim, however, that DRA failed to include an appropriate three-year period in its analysis. DRA used data that PG&E provided of its forecasted and recorded costs from 2010 through 2012. DRA matched these recorded costs with forecasted costs. Although DRA did not include 2013 data in its calculation, DRA used the most recent three years of recorded data that were available. Recorded data for 2013 did not yet exist when DRA made its calculation. DRA did make a comparison of three years of forecasted and recorded capital cost, using 2010 to 2012 combined with forecasted and recorded expense costs from 2010 to 2011. Also, by limiting its

calculation to a three-year consecutive period, DRA reflected the duration of time between GRC test years.

We are not convinced that PG&E's recast of DRA's calculation of the 86% variance offers any more reliable result. In its recasted calculation, although PG&E criticizes DRA for including 2010 data, PG&E, itself, continues to include 2010 data. PG&E, however, also adds a fourth year of data, resulting in a four-year period (i.e., 2010-2013) to derive a revised forecast variance of 94% (compared to DRA's 86%).[86] PG&E's four-year period, however, doesn't correspond to the three-year duration between GRC test years. Instead, PG&E includes the third year of a GRC cycle twice (i.e., once for 2010 and again for 2013). Thus, we are not persuaded that including the extra year more reasonably reflects variations over a three-year GRC cycle compared to DRA's calculation. PG&E's addition of 2013 data also is merely based on comparing one forecast to a later budget, rather than comparing recorded to forecast data, as does DRA.

Accordingly, we are not persuaded that PG&E has offered a more reliable proxy of forecast-to-actual variances based on use of the Concept Cost Estimating Tool, compared to DRA. Although neither PG&E or DRA provide a precise measure of forecast-to-actual variances for the 2011-2013 GRC cycle, by comparing both recorded costs and forecasts for the most recent three-year period, we find it reasonable to rely on DRA's figure for our purposes. We do not believe that DRA's calculation is unreasonable or unfairly inflated.

We also disagree with PG&E's claim that two other exclusions should be made to DRA's calculation of the forecasted-to-actual variance. By making these

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[86] *See* Exh. 60 (PG&E-22) Table 8-6, Line 1, page 8-41.

two other exclusions, PG&E calculates that its forecast variance improves from 94% (as referenced above) to 99% accuracy in use of its Concept Cost Estimating Tool. To support this revised calculation, PG&E's analysis limits its comparison only to the projects that are operational and in development and ignores projects that PG&E cancelled or deferred. Yet, PG&E received funding for these cancelled and deferred projects, as well as for those that were successfully completed. We believe that PG&E should be held accountable for the forecasting methodology for all of its projects, including those that get cancelled or postponed.

DRA compared project funding amounts that PG&E was authorized with what PG&E actually spent. Thus, while DRA did not remove individual projects that were deferred or cancelled, neither did DRA adjust for projects with changes in scope and duration. DRA's calculation was not merely intended to capture forecast variance only in projects that reach completion, but to identify forecast variance from all sources, including variances due to projects that get cancelled or postponed. Such variances also cause ratepayers to provide funding in excess of actual project spending. While PG&E uses unspent money to fund other projects, those other projects were not necessarily evaluated or approved by the Commission. Ratepayers in any case, did not receive the claimed benefits of the forecasted IT projects that were cancelled or postponed.

Contrary to PG&E's claim, we thus find it is reasonable to recognize that there were cancelled projects in the forecast that resulted in zero recorded costs. In this manner, we recognize that the Concept Cost Estimating Tool produced forecasted amounts, used to support increased revenue requirements, for which no costs were incurred. Although PG&E used the unspent funds for other projects deemed to be higher priority, customers did not receive the anticipated

benefits from projects that were cancelled. Similarly, including forecasts for projects deferred to a subsequent rate cycle recognizes that PG&E collected revenue requirements in excess of the actual amount spent for Commission-approved projects during a GRC cycle. By attempting to exclude these sources of forecast variance, PG&E's adjustments to DRA's calculations fail to capture the full effects of relying on the Concept Cost Estimating Tool for forecasting revenue requirements. In conclusion, we are not persuaded that PG&E's claimed recalculation of DRA's 86% variance in the use of the Concept Cost Estimating Tool offers any more reliable figure than does DRA's calculation.

We next address the merits of applying a forecasting variance relating to the prior GRC cycle for purposes of setting 2014 forecasts. Given the practical limits on time and resources involved in conducting a project-by-project review of the accuracy of PG&E's forecasts based on use of the Concept Cost Estimating Tool, we conclude that DRA's uniform 14% adjustment offers a reasonable proxy for potential overstatement in PG&E's forecast, as discussed below.

We recognize that the Concept Cost Estimating Tool is based on the standard industry approach for estimating IT application development costs early in the project lifecycle, and that most IT projects in this GRC have not proceeded past the initial stages of the IT project lifecycle. The GRC cycle requires most software development projects to be forecasted years before they will be implemented. Thus, at the time PG&E forecasts these projects, detailed project requirements and solutions are not yet developed. As a project progresses, more detailed project requirements and solutions are prepared and more refined cost estimates are developed. While we acknowledge this forecasting risk is inherent in the process, ratepayers should not have to be on the losing end of this forecasting risk.

Based on past experience, we anticipate that some projects estimated for the 2014-2016 cycle based on use of the Concept Cost Estimating Tool may get cancelled or deferred to a subsequent GRC cycle. As an additional consideration supporting our adoption of DRA's proposed 14% reduction for IT project costs, we note the concerns raised by TURN regarding the continuing spiral of cost increases for IT assets that need to be refreshed or upgraded every five to seven years. TURN characterizes this cost spiral as an "IT treadmill."[87] In each of its last two GRC cycles, for example, PG&E's request for IT funding reflected a 67% increase. Based on the rapidly escalating forecasts experienced during the prior GRC cycles, and given the exceptional uncertainties inherent in test-year forecasting of IT expenditures, we accept DRA's proposed adjustment to the IT forecast as a reasonable proxy for protecting customers from the unacceptable risks of funding forecasts that exceed what PG&E spends. Accordingly, we apply the 14% adjustment to the adopted IT project forecasts, for the reasons as discussed above.

8. Human Resources (HR)

8.1. Introduction

PG&E forecasts $793.165 million for HR compensation and benefits. DRA recommends reductions of $175.529 million relating to PG&E's forecasts for the STIP, health care plans, severance, and various other employee benefits. DRA also recommends no funding for PG&E's Rewards and Recognition (R&R) Program – an $8.734 million reduction – which is included in the labor budget for

[87] Ex. 123 (TURN Testimony of Schilberg) at 5-6.

each LOB but not in the line items found in Table 8-1 of PG&E's Opening Brief. TURN recommends reductions of $54.596 million.

DRA also makes an alternative recommendation based on the results of the Total Compensation Study (TCS). DRA recommends that if the Commission does not adopt its recommended reductions to the HR programs as described above, that, in the alternative, the Commission adopt a $123.67 million "global adjustment" to PG&E's compensation and benefits based on the results of the TCS.

8.2. Workforce Diversity and Inclusion

Greenlining recommends that PG&E provide cultural sensitivity training for workers whose jobs require contact with customers, including workers who go on service calls in customers' homes and customer service representatives who speak with customers on a daily basis. PG&E currently includes aspects of cultural sensitivity training in its diversity and inclusion training programs. PG&E anticipates that there would be significant cost associated with a training program like the one Greenlining describes. PG&E has not included a funding request for such a program in this GRC. PG&E agrees that Cultural Sensitivity is an important topic and intends to continue its diversity and inclusion efforts, but believe the Commission should not adopt Greenlining's recommendation.

We conclude that PG&E's current funding request adequately addresses cultural sensitivity and inclusion training programs. We do not adopt Greenlining's recommendations for additional training.

8.3. Employee Compensation

8.3.1. Total Compensation Study (TCS)

In PG&E's 1996 GRC, PG&E was required to present a TCS in which independent experts undertook analysis with regard to benchmarks, job

matching, and the selection of comparable firms. The Commission stated that "[w]ithout such independent analysis, we will not consider PG&E to have met its burden to demonstrate the reasonableness of its employee compensation."[88]

Consistent with prior practice, PG&E and DRA jointly administered the TCS in this GRC, selecting Mercer (US) Inc., an independent consulting firm, to perform the TCS. PG&E and DRA jointly developed the scope of the study and participated in team meetings throughout the study. PG&E relied on Mercer's professional judgment to make final decisions about the study methodology, how to categorize data, and how to interpret the study results.

DRA claims that the TCS revealed that PG&E's total compensation was 9.9% above the market median, with base salaries 5.5% above market and benefits 56.2% above market. DRA proposes a revenue requirement reduction in PG&E's employee compensation in excess of market levels as determined by the TCS. DRA disputes PG&E's argument that a 10% variance is reasonable on the facts of this case or the elements of the TCS. DRA claims that the conditions that existed in 2000, when the Commission found a 7.3% variance acceptable, did not exist in the current survey. The subsequent TCS surveys corrected mistakes in methodology. DRA notes that, in more recent cases, the Commission has stated that a 5% variance should be the basis for a reasonable compensation level.[89] DRA thus recommends that PG&E's compensation be brought within the 5% level and calculated at this level for all PG&E employees, as follows:

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[88] D.95-12-055, mimeo, at 21-22.

[89] Ex. 82 (DRA-14) at 5, footnotes 13-17.

Calculation of Total Employee Compensation Above Market
(In Thousands of Dollars)

Benchmarked total compensation (a) = $1,362,892
Benchmarked percentage of employees (b) 54%
Potential total compensation (c) = (a) / (b) * 100 = $2,523,874
Percentage over market, 9.9% less 5% (d) = 4.9%
Total adjustments necessary to bring PG&E
to within 5% of market (e) = (c) * (d) = $123,670
Source: Total Compensation Study, Ex. (PG&E-8), at 4-11.

DRA recommends several specific adjustments to individual compensation benefit programs as set forth in Ex. 82 (DRA-14) at 1-2. DRA recommends that, in the alternative, if its individual proposed reductions are not adopted, the Commission make a global reduction to labor costs of $123.67 million to bring PG&E's overall total compensation and benefits package to within the Commission's previously recognized variance allowance of 5%, and that PG&E should absorb the difference when employees earn above-market compensation.

PG&E opposes DRA's proposed global adjustment, arguing that: (1) the TCS found that PG&E's total compensation was competitive with the market, not "well above market" as DRA claims; (2) DRA's global adjustment is not required as a matter of Commission policy; (3) notwithstanding the TCS conclusion that PG&E's total compensation is competitive, the TCS used a different set of underlying assumptions as compared to previous studies, which had the effect of significantly overstating the value of PG&E's benefits and total compensation relative to the market; and (4) the amount of DRA's proposed adjustment is incorrect.

Discussion

We find insufficient basis to adopt DRA's global recommendation to reduce labor costs by $123.67 million to bring PG&E's overall total compensation

and benefits package to within a variance of 5% above the market median. DRA's global adjustment recommendation is based on the premise that PG&E's total compensation is 9.9% above the market median stated in the TCS.

For purposes of the TCS, "Total Compensation" includes base salary, short-term incentives, and the value of employee benefits. The TCS evaluated PG&E's compensation and benefits programs in place in 2011. The TCS concluded that PG&E's Total Compensation was competitive with the market based on aggregate total compensation being within a +/-10% range. In its initial study, the TCS did not account for changes that PG&E already made to pension, employee medical, and 401(k) programs that increase their competitiveness. DRA's proposed adjustment does not take into account those plan design changes that PG&E has already made.

PG&E asked Mercer to re-run the TCS using employee benefit plan designs PG&E proposed for its 2014 GRC that were not included in the initial study. Mercer concluded that after accounting for the plan design changes already implemented, PG&E's total compensation is only 5.2% above the market median (Ex. 62 (PG&E-23) at 1-7, 1-8, and 1A-1). Mercer also used different benefits valuation assumptions than those used in prior studies, which overstated PG&E's benefits valuations and Total Compensation relative to market (Ex. 62 (PG&E-23), at 5-1, 5-2, and 5-5)). An adjustment to bring PG&E's total compensation from 5.2% above the market median to 5% above market median would be smaller than DRA recommended.

The TCS methodology differed relative to previous total compensation studies. Mercer examined cash compensation using survey sources and determined employee benefits values from select peer companies in its database. Mercer then combined the two to arrive at a total compensation value. Previous

studies used cash and benefits data from the same comparator group of companies. The Mercer study relied on a much different comparator group of companies than in prior studies. To address concerns regarding the robustness of the benefits valuation database of comparable companies, DRA and PG&E required that Mercer undertake its best efforts to expand its database of relevant companies. Mercer considered the size of the study and the robustness and distribution of the collected data in determining that a +/-10 percent range of competitiveness was appropriate for the study.

Based on the revised figures calculated by Mercer, as discussed above, we do not accept DRA's calculation showing PG&E employee compensation exceeding the market median by 4.9% as the reduction in PG&E's forecasted employee compensation necessary to reflect a 5%-above-median limit (i.e., 4.9% = 9.9%-5%).

While we conclude that DRA overstates the appropriate employee compensation adjustment, we do agree with DRA that employee compensation levels funded by ratepayers should be limited to 5% above the market median consistent with existing Commission policy. In PG&E's last fully-litigated GRC, in 1999, we approved employee compensation of 7.23% above the market average. PG&E's 2007 GRC, employee compensation was deemed competitive as it fell within the +/-10% range that Towers Perrin considered competitive in that study. Particularly in view of the cumulative cost burdens placed on ratepayers in this GRC, however, we conclude that funding employee compensation that exceeds 5% above the market median is excessive. Although we previously considered employee compensation to be competitive if it fell within a 10% variance of the market rates, we conclude that the more narrow limit of a 5% variance is warranted for this proceeding. Limiting the test year

increase for total employee compensation to a parameter of 5% above market limits the cost burden on ratepayers while still providing compensation sufficient for PG&E to attract and retain a competent labor force. The use of a 5% variance is consistent with more recent Commission policy.

If we use Mercer's revised figures showing PG&E employee compensation as being 5.2% above the market median, based our adopted limit of 5% above the median, the resulting reduction in total employee compensation would be $5,047,748.[90] Since we are already reducing employee compensation relating to the STIP, as discussed in the next section, however, no additional reduction is required here to bring total employee compensation within the 5% limit.

8.3.2. Short-Term Incentive Plan (STIP)

PG&E forecasts $130.2 million to fund its STIP and $107,000 for STIP for the Corporation in 2014. The STIP is an incentive plan for PG&E management employees, professionals, and non-represented employees, and represented employees where agreed to through collective bargaining. The STIP puts a portion of an employee's pay at risk if targeted objectives are not met. Every PG&E supervisor, manager, director, and executive participates in STIP. PG&E does not seek STIP funding of STIP for executives in this GRC.

PG&E's STIP forecast consists of: (1) a Target Payout; (2) Actual STIP Cost; (3) Company Performance Score; and (4) Individual Employee STIP Payments. The Target Payout is the amount that PG&E would pay participants if the Company achieved target performance on all its performance measures. PG&E

[90] The adjustment of $5,047,748 is equal to 0.2% of PG&E's total employee compensation figure of $2,523,874,000 (=5.2%-5%) (from the Total Compensation Study, Ex. (PG&E-8), at 4-11.)

reflects a mix of performance measures in the STIP relating to operating performance, employee safety, customer satisfaction, and financial earnings. PG&E performance scores are based on safety and customer satisfaction metrics to account for about 70% of the STIP, while the remaining 30% is based on PG&E's Earnings From Operations (EFO) metric.

If particular performance targets are met, eligible employees receive a STIP payout by multiplying their eligible earnings by their target participation rates. The Company Performance Score is based on performance goals set by the Compensation Committee of the Board of Directors, which also approves the STIP each year.

PG&E's 2014 forecast includes a $15.9 million adjustment for additional employees that PG&E proposes to hire and a reduction of $231,000 for PG&E Corporation employees.

DRA recommends an overall STIP reduction of $84.6 million for PG&E and $70,000 for PG&E Corporation, resulting in a forecast of $45.572 million TY 2014 STIP for PG&E and $37,000 for PG&E Corporation. DRA proposes that ratepayers be allocated no more than 35% of the STIP costs, arguing that 30% of STIP costs exclusively benefit shareholders. DRA believes the remaining 70% should be shared between ratepayers and shareholders as follows:
(1) shareholders would pay for 30% of STIP, claiming that the EFO metric provides no benefit to customers; and (2) shareholders would pay another 35% of the STIP costs for half of the Safety and Customer metrics because shareholders and customers both benefit from a safe, reliable system. DRA observes that the STIP has increased at compounded annual percentage rates well in excess of the general rate of inflation over the past decade, and argues that these STIP limits

assure that ratepayers are not responsible for significant rates of increase in discretionary STIP costs witnessed over this time frame.

TURN recommends a reduction of $33.198 million in ratepayer-funded STIP in 2014, excluding $12.524 million and $18.786 million for the Customer Satisfaction and Financial Performance components of STIP funding, respectively. TURN believes the portions of the STIP attributable to the EFO and Customer Satisfaction metrics provide no benefit to customers, and should instead be funded by shareholders. TURN's recommendation to exclude $12.524 million for the Customer Satisfaction component of the STIP stems from TURN's suspicion that PG&E's Customer Satisfaction measures have the potential to be gamed. Also, TURN does not believe the STIP Customer Satisfaction metric actually benefits ratepayers, or that the metric is significantly correlated with actual customer satisfaction, as there are factors other than utility performance that may affect a customer's satisfaction with the utility.

TURN also recommends the exclusion of $18.786 million relating to the reasonableness of how EFO is calculated as a STIP target measure. PG&E proposes to use EFO in STIP that excludes income or expenses associated with unusual events or circumstances that are not part of ongoing core operations. TURN claims that the EFO measure can be used to create the appearance of better performance than PG&E must report to financial markets, thus showing better performance for purposes of STIP.

TURN claims that PG&E provides no information regarding what income and expenses have been excluded, the exact target for this STIP measure, or the upper or lower limits on the range that is considered for STIP. TURN claims that the EFO measure is a product of unspecified internal adjustments measured against unknown goals. PG&E responds that the EFO metric measures earnings

from core operations and is generally preferred by the external financial community.

PG&E believes that customers are better off with a portion of management pay at risk, and claims that DRA is essentially taking the position that any compensation practice that promotes success in financial, operational, or safety areas should be disallowed to some degree. PG&E argues that conditioning management employees' compensation, in part, on the achievement of those goals is a widely-accepted practice and important part of employee compensation.

PG&E argues that DRA's or TURN's recommendations would further reduce customer-funded cash compensation for STIP-eligible employees. Paying competitive salaries for management employees is a reasonable cost of providing service, whether through base pay or a combination of base and variable pay. PG&E claims it is entitled to full reimbursement of these costs in rates.

TURN criticizes PG&E's discussion that customer-funded cash compensation levels for STIP-eligible employees are below market levels and could fall further below if DRA's and TURN's recommendations are adopted. PG&E argues that cash compensation is a valid data point to discuss because it shows how DRA's and TURN's proposals could affect the STIP-eligible cohort of employees. TURN suggests that the reasonableness of PG&E's STIP request should be judged based on the Company's total compensation in the aggregate. PG&E agrees. The Commission has previously taken that approach, noting that is how it would evaluate this portion of compensation if it were included in base pay. PG&E argues that approach demonstrates the reasonableness of its forecast.

Assuming a target STIP, PG&E claims that the total cash compensation for STIP-eligible employees as a group is already below market levels at 95.4%.

PG&E claims that TURN's recommendations would cause the customer-funded cash compensation for STIP-eligible employees to fall well below market levels. TURN responds that PG&E is using the incorrect measure to compare employees' compensation to market levels, relying only upon cash compensation.

Discussion

We approve ratepayer expense funding of $89 million of the STIP program for test year 2014. Our adopted allowance incorporates the exclusion of the EFO and Customer Satisfaction STIP metrics, as proposed by TURN. After reducing PG&E's forecast for these exclusions, we apply a 10% reduction to provide some degree of sharing of cost responsibility between ratepayers and shareholders.[91] We conclude that offering employee compensation in the form of incentive payments is useful for recruiting and retaining skilled professionals and improving work performance. Conditioning a portion of management employees' compensation on achievement of specific company goals is a generally accepted compensation practice. We conclude that ratepayers derive benefits from various elements of STIP and should bear a reasonable level of costs commensurate with such benefits. We also conclude, however, that PG&E shareholders benefit from STIP. For some measures, shareholders benefit as much as or more than ratepayers.

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[91] We derive the STIP funding allowance as follows. TURN's proposed disallowances of $12.524 million for the Customer Satisfaction component and $18.786 million for the EFO component reduce PG&E's forecast from $130.2 million to $98.9 million. By subtracting 10% from the remainder, we derive a total of $89 million (=$98.9 ÷ 9.9 million).

In particular, we conclude that the two elements of STIP compensation essentially benefit shareholders, but without a clear demonstrable benefit to ratepayers. We adopt TURN's recommendation that these STIP elements should not be paid for by ratepayers, as discussed below.

TURN proposes to exclude $18.786 million for the Financial Performance measure of EFO. This is the largest single metric of the weighted STIP measures. DRA's estimate removes 30% of PG&E's forecast measure for Financial Performance/EFO. DRA also believes that the EFO does not substantially benefit ratepayers and should be funded entirely by shareholders. TURN also proposes removal of PG&E's EFO metric for similar reasons.

Based on PG&E's past behavior, we conclude that incentives to increase earnings can potentially work at cross purposes with incentives to address safety or reliability issues. For example, the Overland Report found that PG&E's return on equity from gas operations from 2003 through 2010 exceeded its authorized return and gas transmission and storage provided an even greater return. Yet, PG&E's long-term gas safety programs "were poorly funded throughout the audit period" (except for copper service replacement). In such past cases, improving earnings was not a function of motivating desirable employee performance.

STIP adjustments for EFO began in 2009, as PG&E was conducting the Gas Effectiveness Evaluation and Mitigation (GEEM) Program accelerated leak surveying and repair. Shareholders suffered reduced return due to the program, but the STIP was not impacted. If GEEM been included in financial results, the financial component of STIP bonuses would have been at 85.05% of target, not 157.4%. Based on these considerations, we exclude ratepayer funding for this component of STIP.

We further reduce PG&E's revenue requirements by $12.524 million to exclude the Customer Satisfaction STIP metric, weighted at 10% of STIP. PG&E has not demonstrated a convincing correlation between actual customer benefits and the metrics tracked by the STIP. As noted by TURN witness Sugar, "[g]iven the variety of factors than can affect customers' perception of utility performance, changes in customers' general 'satisfaction' with the utility may reflect the result of careful packaging or messaging rather than improved utility service delivery."[92] TURN provides the example of customer satisfaction surveys utilized by PG&E. PG&E routinely uses any contact a customer may have had with PG&E, including through merely paying their bill, as reasonable indicators of customer satisfaction. Furthermore, the STIP metric does not include the actions of PG&E employees that experience the greatest degree of customer contact, e.g., customer service representatives and field employees. Yet, managers, engineers, directors, and other employees covered by STIP actually have little direct impact on customer satisfaction.

After excluding the costs, we conclude that the remaining elements of the STIP provide benefits both to ratepayers and shareholders. We thus believe that ratepayers should not bear the entire burden of the STIP. Expecting shareholders to absorb some degree of cost responsibility for STIP does not conflict with traditional cost-of-service ratemaking principles. To the contrary, the sharing of cost responsibility promotes a reasonable matching of costs with benefits experienced both by ratepayers and shareholders. In this manner, ratepayers bear reasonable costs for funding STIP metrics in relation to the benefits derived.

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[92] Ex. 131 (TURN/Sugar Testimony) at 8.

Adopting a sharing of STIP costs is consistent with our practices in prior proceedings where we have authorized ratepayer funding of employee incentive compensation while concluding that ratepayers should not bear the entire burden of such costs. In past proceedings, we have applied different degrees of cost sharing between ratepayers and shareholders.

In D.00-02-046, we adopted a policy of allowing 50% recovery of targeted employee incentive program costs from ratepayers, stating:

> [S]hareholders and ratepayers alike benefit from the good performance that incentive programs such as PIP seek to encourage. We continue to believe that equal sharing of cost is fair, and that it provides appropriate incentives to the utility to perform in ways that benefit ratepayers and shareholders alike. Moreover, since the actual payout is less than the target payout in any year when employees do not perform well enough to earn targeted payouts, there is an unacceptable risk of overcollection of costs in the test year if we allow the inclusion of 100% of the targeted payout in rates. Continuing our policy of allowing 50% of targeted payouts mitigates this concern.[93]

DRA determined that PG&E's actual STIP payout has exceeded its target STIP payout for eight of the last ten years (2003-2012). DRA proposes equal sharing of the forecast STIP costs between ratepayers and shareholders for measures relating to Public Safety, weighted 24%, Employee Safety, weighted 16%, and Customer Satisfaction, weighted 30%.

Since we have already completely excluded two STIP metrics, we conclude that a further reduction in ratepayer funding of 50% for remaining programs

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[93] D.00-02-046, mimeo, at 256.

would be excessive. We believe, however, that some degree of cost sharing is reasonable.

For example, in D.12-11-051, we reduced recovery of SCE's short-term incentive program cost by 10%. In so doing, we determined that ratepayers should not bear the entire burden of a rapidly growing, discretionary incentive program costs which, in some areas, may enhance value for shareholders more than benefit ratepayers. We similarly adopt a 10% reduction of PG&E's remaining STIP costs based on similar principles as applied in reference to SCE.

We do not believe that our adopted reductions in ratepayer funding of STIP will necessarily cause PG&E to reduce the overall level of compensation for STIP-eligible employees to "well below market levels." PG&E contends that assuming a target STIP, the total cash compensation for STIP-eligible employees as a group is already below market levels at 95.4 %. Against the measure of total compensation, however, not just cash compensation, the Mercer TCS concludes, PG&E's aggregate total compensation is 5.2% above the market median. Moreover, a reduction of ratepayer funding does not automatically mean that PG&E must to reduce the underlying STIP benefit to employees. Shareholders may find it in their interest to replace the funds that ratepayers do not cover.

8.3.3. R&R

PG&E requests $8.734 million to fund the R&R program. The R&R program is one way in which PG&E can recognize and encourage employees to work safely, go above and beyond to achieve results, and encourage innovation. These behaviors benefit customers as PG&E is able to more efficiently and effectively deliver services. PG&E did not specifically forecast the amount of R&R expenses embedded in its 2014 revenue requirement request. According to PG&E, it recorded $7.031 million of GRC-related cash and non-cash R&R

expenses in 2011. PG&E escalated its actual 2011 expenses by 3% per year for three years.

DRA recommends no funding for this program, claiming it provides no clear benefit to customers and is not necessary to operate the utility. DRA argues that it is inappropriate for customers to subsidize programs that are unnecessary or not required for utility operation.

PG&E claims that the R&R program is consistent with commonly accepted compensation practices, and these types of awards are a low-cost way of showing hard-working employees that they are valued, appreciated, and that their extra contributions do not go unnoticed. The R&R program costs are charged to the employees' cost centers, included in recorded adjusted costs and escalated in the same manner as other materials and services.

Discussion

We approve PG&E's forecast for $8.734 million to fund the R&R program. This program is similar to those offered by the other California utilities. We conclude that the program provides a reasonable way to reward employees who help improve the operations of the utility, or provide exceptional service, or otherwise distinguish themselves. The program helps promote retention of strong employees, which benefits both PG&E and its ratepayers. We also conclude that the program costs are reasonable, as PG&E is not forecasting an increase in program costs other than normal escalation.

8.3.4. Labor Escalation (including Attrition)

PG&E proposes a 3% escalation rate for non-union employees. For union-represented employees, PG&E proposes to use labor escalation rates presented in its most recent collective bargaining agreement for 2012 to 2014, as seen in Ex. 35 (PG&E-8), at 5-12, Table 5-3, lines 1-4. PG&E's composite labor

escalation rate, which is a weighted average of the escalation rates for union represented and non-union represented employees, is 2.79%. PG&E proposes to apply this composite escalation rate to the forecast period 2012-2014 as well as the attrition years 2015 and 2016.

DRA claims that PG&E has not justified applying a higher escalation rate for its non-union employees, and recommends that the Commission apply an across-the- board labor escalation of 2.61%, the average increase for employees subject to collective bargaining.

The differences between PG&E's and DRA's proposals are greater in the post-test year period. PG&E proposes the same 2.79% escalation rate for the post-test year period, whereas DRA wants to "reign in" labor costs and argues for wage escalation based on fourth quarter 2012 projections of the Consumer Price Index (CPI) (national), which would be 1.7% for 2015 and 1.9% for 2016.

The main differences between DRA's and PG&E's union and non-union escalation rates forecasts are due to PG&E's use of surveys it has not previously used to forecast management wage increases. The Commission has previously used labor union agreements to forecast management wage increases.

PG&E disagrees with use of the CPI as a proxy for wage increases, arguing that the CPI is a price index, not a wage index. If, however, the CPI were to be used, PG&E contends that consumer inflation faced by PG&E workers and their customers should apply, which is estimated to exceed 3%. This would actually increase PG&E's forecast beyond the requested 2.79%. Much of the Bay Area is witnessing rapid increases in housing costs.

Discussion

We adopt PG&E's forecasted average escalation rate of 2.79%. We decline to adopt DRA's recommendation to use CPI as the basis for PG&E's cost

escalation. The CPI measures changes in consumer prices and is not the best proxy for a wage index. PG&E's escalation rates are based on weighted average wage and salary increases for: (1) collective bargaining units,[94] (2) clerical; and (3) management/administrative and technical.

Using a national index for deriving escalation, rather than a local one, would cause PG&E to lag behind other employers in providing competitive wage increases to attract quality employees. Over the long-term, customers would not benefit from such an approach.

8.3.5. Employee Health Plans (including Escalation)

PG&E requests ratepayer funding of $385.1 million for its medical programs less $30.7 million in estimated employee health care contributions. Based on Towers Watson trend forecasts, PG&E also seeks escalated health care costs for the post-test years of $378.7 million and $409.1 million for 2015 and 2016, respectively.

DRA proposes two reductions in health care costs. The first reduction of $35 million relates to DRA's lower estimate of employee headcount, and the second relates to DRA's position that additional employee health care contributions should be required, thereby reducing PG&E's overall health care plan request by $40.352 million. DRA claims that employees should share in their health care contributions at the national average rate of 23.8%, as shown in a Towers Watson employer survey, rather than the 7.5% rate currently applicable to PG&E employees. DRA asserts that PG&E has offered no explanation as to

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[94] The bargaining units consist of IBEW-represented employees, ESC represented employees,

Footnote continued on next page

why its employees should not be sharing medical care costs at a similar rate as employees at other companies.

Discussion

We adopt PG&E's 2014 forecast of medical program costs as reasonable. We determine any applicable adjustments based on overall differences between PG&E's employee headcount and our adopted forecasts. We find no basis to reduce ratepayer funding of PG&E's medical program costs based on national averages of employees' share of contributions to their health care costs. We recognize that a wide range of employer health contribution sharing exists among employers nationally, and such broad averages do not accurately reflect PG&E's characteristics. Also, there are other ways that employees share in their medical plan costs. Employee contributions to their health care coverage are also based on plan provisions, including deductibles, coinsurance, and out-of-pocket maximums. PG&E's medical plan deductibles and out-of-pocket maximums are at the high end of the California range. Taking these features into account can actually lead to employees' bearing an overall cost share significantly higher than charging employees 24% of the annual premium.

We recognize that PG&E and its unions have negotiated a new health plan designed to reduce health care costs through more efficient plan design and with incentives for employees to take a more active role in their own health management. We conclude it is appropriate to approve PG&E's proposed funding increases consistent with the terms of the new health plan. We decline to adopt DRA's proposal calling for increases in employee contributions and

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and SEIU-represented employees.

disallowances of PG&E health care costs which would conflict with PG&E's negotiated employee health plans.

In Section 12 on Post-Test-Year Attrition Issues, we address DRA's proposal to reduce PG&E's proposed post-test year escalation, based on Global Insights forecasts from 8.4% to 6.4% in 2015 and from 8.2% to 6.3% in 2016.

8.3.5.1. Health Plan Escalation Rates

PG&E proposed a 5.4% health cost escalation rate for the 2014 test year, below national and local trends. DRA does not contest PG&E's escalation estimate. TURN proposes use of a 2.8% escalation rate instead.

PG&E's forecast of medical cost escalation was derived by Towers Watson through use of a medical cost trend developed to forecast expected PG&E experience that is consistent with the approach used in the 2011 GRC. TURN claims that Towers Watson relied on a stale CMS study. PG&E claims that they did not.

DRA proposes to reduce PG&E's post-test year health cost escalation forecast from 8.4% to 6.4% in 2015 and from 8.2% to 6.3% in 2016. TURN proposes to reduce medical escalation to 6% and 7% for 2015 and 2016, respectively. DRA bases its forecast on the Global Insights indices. PG&E notes the following problems, claiming that the Global Insights forecast:

- Includes cost elements such as dental and vision that PG&E forecasts separately because they have lower cost trends;
- Excludes cost drivers for geographic location and demographics of PG&E's employee population that affect PG&E's medical costs; and
- Reflects low response rates and inclusion of employers that may eliminate or reduce benefits under their plans (which produces a downward bias for the remaining employer plans).

DRA complains that PG&E's health care costs continue to rise. PG&E responds that it should be evaluated against realistic health care trends, not a goal of zero cost escalation. The savings trend that PG&E is projecting should accrue to customers, not just through this rate cycle but beyond.

DRA cites state-wide and national premium surveys, showing that PG&E's premiums for family coverage were approximately 3.5% higher than the state average and 8.5% higher than the national average. PG&E believes such national and state-wide data do not recognize the demographics of PG&E's employee population, which are reflected in premium rates, nor PG&E's location in Northern California, and especially the Bay Area where premiums are higher. For example, PG&E seeks $1,434 on average for family coverage while Bay Area Rapid Transit's average cost for families averages around $4,000 per month for families of three or more.

Discussion

We adopt PG&E's forecast of 5.4% health cost escalation rate for 2014. The 2014 forecast medical trend rate of 5.4% provided by Towers Watson, based on PG&E's experience, is lower than trend findings from recent California and national surveys on health care costs. The approach used is typical of how large employers with both insured and self-funded medical plans forecast health care costs. We find no basis to adopt the lower escalation rate proposed by TURN. As noted by PG&E, TURN's proposal is based on a mistaken belief that the Towers Watson study was based on a stale CMS study.

We separately address attrition issues relating to cost escalation in Section 12.

8.3.5.2. Non-Contested Health and Insurance Items

PG&E forecasts $33.3 million for dental benefits, $3.4 million for vision benefits, and $708,000 for life insurance benefits. No party has disputed PG&E's base forecast for these programs. We adopt PG&E's forecast for these programs and incremental amounts related to headcount growth consistent with our decision on PG&E's labor forecast.

8.3.6. Post-Retirement Employee Benefits

PG&E forecasts $1.2 million for Postretirement Medical, $49.392 million for Postretirement Medical Trust Contributions, $3.0 million for Postretirement Life Insurance, and $11.8 million for Postretirement Life Insurance Trust Contributions. No party disputed PG&E's forecast for these programs, and we adopt PG&E's 2014 forecast for these programs.

8.3.7. Disability Trust Contributions

PG&E forecasts $31.307 million for Long Term Disability Trust Contributions and $1.31 million for Pay-As-You-Go Disability Benefits. No party disputed PG&E's forecast for this program, and we adopt PG&E's 2014 forecast for it.

8.3.8. 401(k) Funding

PG&E's forecast for matching 401(k) contributions in 2014 is $77.981 million, along with a forecast of $7.798 million in associated headcount growth. TURN recommends a decrease in the forecast (before reflecting headcount adjustments) of $9.038 million, primarily by relying on a five-year (2007-2011) average of PG&E's matching contribution data plus an increment related to a new plan to be available to employees in 2014. PG&E, in contrast, makes its forecast by relying on matching contribution data from 2011. DRA does not recommend any reductions.

TURN believes that PG&E's recorded 2011 matching contribution expense is anomalous, and higher than would be expected based on the last five year's plan expenses. PG&E claims, however, that the 2011 recorded data reflects important changes in plan design and headcount that alter the earlier trend average (2007-2010) and makes use of 2011 data necessary to accurately predict the test year.

Discussion

We adopt PG&E's forecast for 401(K) matching funding contributions, and decline to adopt TURN's proposed reductions. PG&E provides a reasonable explanation of its use of 2011 data, noting that various changes in plan design and headcount alter the earlier trend average in comparison to 2011. These changes relate to collective bargaining provisions for matching contributions, changes in employee population, and wage level growth.

8.3.9. Supplemental Executive Retirement Plan

PG&E forecasts $3.485 million in 2014 for its "Supplemental Executives Retirement Plan" (SERP) for non-qualified pensions and administrative costs. DRA recommends $0 in funding for this item, arguing that ratepayers should not bear exclusive executive benefits costs that exceed what is authorized by the federal tax code, other pertinent laws and regulations, or what is offered as part of the company's normal employee coverage. PG&E disagrees, claiming that the underlying benefit formula for pension benefits is the same for all employees, including executives. As explained below, these benefits are not special, nor are they tax disfavored. In any event, buried within this $3.485 million total is $250,000 of administrative costs that relate to administering all employee pension plans, which DRA should not have objected to, and which should be allowed

separately in full. This should leave only $3.26 million for nonqualified pensions under dispute.

PG&E argues that the Commission has a long history of authorizing recovery for the non-qualified pension costs of California utilities, and notes that DRA only cites decisions from regulatory agencies outside of California to support its recommendation to disallow all requested recovery.

Discussion

We adopt ratepayer funding for only 50% of PG&E's SERP forecast for non-qualified pensions and administrative costs. These non-qualified plans make retired employees whole for benefits they would have received, but for IRS limitations on qualified trust funding. The IRS tax laws address separate public purposes, but do not determine appropriate ratemaking treatment of these costs. As noted by PG&E, the Commission has previously authorized cost recovery of employee non-qualified pension plans. In the most recent SCE and Sempra GRC decisions, however, we only authorized recovery of one-half of those non-qualified pension plans.[95]

Based on similar principles, we adopt ratepayer funding only for 50% of PG&E's forecast cost for SERP non-qualified pensions. We apply the 50% funding allocation to a pension cost forecast of $3.26 million, which is net of the $225,000 administrative costs for all employee pension plans which we allow in full. We thus reduce PG&E's SERP expense forecast by $1.63 million.

We applied an equal cost sharing of pension costs between ratepayers and shareholders in the SCE and Sempra GRCs based on the finding that the pension

[95] See D.12-11-051 at 477 and D.13-05-010 at 887.

plans primarily benefit the utility's executives and shareholders and were offered to entice them to work for a prolonged period of time.

In the Sempra GRC, the Commission also found that pension plan benefitted ratepayers by providing a continuity of executives and managers who are familiar with the corporate culture and the policies and objectives of the companies. PG&E's pension plan request here, however, is different from that of SCE and Sempra. PG&E seeks recovery of plan non-qualified expenses only on a "pay as you go" basis, rather than based on Financial Accounting Standards Board Accounting Standards Codification Topic 960 (ASC 960). PG&E's requested ratepayer funding covers only out-of-pocket payments to retirees. In contrast, the ASC 960 non-qualified pension expense, as requested by SCE and Sempra, included costs for both active executives earning benefits and current retirees. PG&E's expense for non-qualified pensions on an ASC 960 basis was $6.3 million in 2012 compared to its forecast of $3.26 million for nonqualified pensions in this GRC. In view of the fact that PG&E's forecast does not include active executives earning current benefits, PG&E argues that the rationale for a reduction in funding in the Sempra and SCE proceedings does not apply here.

We are not persuaded, however, by PG&E's argument that differences between the pension costs at issue here versus those in the Sempra or SCE GRCs warrant full ratepayer funding in PG&E's case. We recognize that PG&E's pension benefits are paid only to retirees, so that any incentive for "continuity of executives and managers" would not apply to them. To the extent that PG&E's pension plan costs exclude currently active executives earning benefits, and cover only out-of-pocket costs, those benefits mainly benefit the retired executives.

The distinguishing characteristics of PG&E's pension plan, however, do nothing to enhance benefits to ratepayers in comparison to the Sempra pension plan. On the other hand, currently employed executives and managers have a greater incentive to continue their employment in anticipation of PG&E's policy of continuing to provide pension benefits after retirement.

Thus, although the details differ among the utilities regarding how the pensions are applied and paid, the broad principle is the same that both ratepayers and shareholders derive benefits therefrom. Ratepayers benefit by being served by a utility that can retain executives and managers who are familiar with the corporate culture, policies and objectives. As a result, we find it appropriate to apply a similar ratemaking convention as applied in the SCE and Sempra GRCs, and assign only 50% of PG&E's forecast SERP pension costs to ratepayers. We thus reduce PG&E's SERP forecast by 50% for ratemaking purposes.

8.3.10. Service Awards

PG&E requests recovery of the $1.3 million expense for service awards because it an appropriate and cost-effective expense that serves the interest of customers. DRA claims that service awards are a "superogatory expense" which should be excluded from ratepayer funding. DRA claims that funding of Service Awards does not provide a clear and identifiable benefit to ratepayers, nor is necessary to operate the utility business. DRA argues that if PG&E wants to express its appreciation to its employees, it can do so at its own expense, rather than that of its ratepayers. DRA recommends zero funding for the Service Awards program. If the Commission finds that PG&E's Service Awards is a reasonable program for ratepayers to support, DRA recommends that a

significant adjustment be made to bring the cost more in line with the program offered to State employees, or that shareholders contribute to the program.

In the recent Sempra GRC (A.10-12-005/006), the Commission only funded 50% of the request in D.13-05-010, reasoning that part of the expense benefits shareholders. PG&E claims this decision and others which deny any funding are in error, and argues that benefits to customers of these programs have not been properly explained by the utilities in past litigation involving recovery of these service awards. Unregulated businesses, including most of the Fortune 500, provide these tangible awards. Those businesses only earn additional profits if their employees are more productive than those of competitors and/or provide better service (to attract more customers) on account of receiving these awards. Competitive businesses would only provide these benefits if they believed they were cost-effective in terms of enhancing customer service and productivity. If competitive businesses provide such awards, and find them cost effective, PG&E questions why such non-cash service award costs are not also appropriate for California utilities.

Discussion

Consistent with our treatment of similar costs in the Sempra GRC proceeding, we conclude that only 50% of PG&E's $1.3 million expense for service awards should be allowed. We conclude that service recognition is related somewhat to the employees' job activities and continuity of employment, but is also related to building loyalty between the employees and the companies. Accordingly, in order to allocate a share of the costs to corporate shareholders, we reduce PG&E's forecast of ratepayer funding for this item by $650,000. This treatment provides some recognition of the benefits to ratepayers while also

considering corporate shareholder benefits relating to building loyalty between the employees and the company.

8.3.11. Tuition Support Payments and Relocation Costs

PG&E forecasts $3.86 million and $6.32 million for 2014 tuition refund and relocation programs, respectively. DRA recommends 2014 reductions of $0.98 million for tuition refund programs and $1.262 million for relocation expenses using a historical three-year average (2009-2011). DRA also does not accept increases that would occur in these expenses, if PG&E's total headcount is adjusted upward as PG&E has forecast.

PG&E's forecast of tuition refunds reflects anticipated annual tuition cost increases of 10% per year. While tuition rates in California continue to rank among the lowest in the nation, PG&E's testimony described why Proposition 30, passed in 2012, is likely to provide only temporary relief for higher education costs. PG&E claims that a three-year historical average of 2009-2011 does not reflect these cost increases, and will not allow PG&E a reasonable opportunity to recover these costs.

Discussion

We adopt PG&E's forecast for tuition refund programs and relocation expense. We conclude that PG&E has reasonably justified its forecasts for these items. With many job functions requiring years of training and experience, and the growing number of employees who are eligible for retirement, PG&E has increased hiring to create a pool of qualified workers. Relocation is part of the recruitment process, and instrumental in gaining acceptance of employment offers by experienced candidates. PG&E expects increased hiring and related relocation activities, but finds it difficult to predict the cost of relocation benefits

in a single year. Recorded actual 2012 expenses were double the 2011 relocation cost, and were over 30% greater than PG&E's 2012 forecast. For forecasted relocation costs, we accept PG&E's use of a five-year, rather than three-year, average. We conclude that a three-year average does not properly reflect volatility in relocation costs.

8.4. Workers' Compensation

PG&E forecasts $41.6 million for workers' compensation benefits and related costs for 2014. No party has disputed this forecast. We adopt PG&E's 2014 forecast for this program.

8.5. Workforce Management Program

PG&E forecasts $13.3 million for its Workforce Management Program costs in 2014. PG&E does not seek recovery of severance costs for executives in this GRC. Of the above amount, $10.8 million is undisputed. DRA recommends a reduction of $2.5 million.

PG&E used a five-year average of costs from 2007-2011 for its forecast. DRA's reduction is based on a two-year average. PG&E claims DRA does not reflect the nature of the program.

Discussion

We adopt PG&E's forecast of $13.3 million for its Workforce Management Program costs in 2014. DRA acknowledges that program costs fluctuated over the 2007-2011 period, but claims 2009 was an anomaly that should be excluded from the average that makes up the forecast. We recognize that program costs fluctuate for a variety of reasons including process changes or new technology. Between 2007 and 2009, PG&E eliminated over 100 positions each year, followed by lower workforce reductions in 2010, and more than 250 in 2012. The five-year forecast eliminates volatility from year to year. Eliminating the higher years as

DRA proposes, penalizes PG&E for taking steps needs to reduce workforce as requirements change.

9. A&G Expenses

9.1. Introduction

PG&E forecasts $245.2 million in A&G Department costs, reflecting costs not directly chargeable to a specific utility function, and including general office labor and supplies, insurance, casualty payments, consultant fees, employee benefits, regulatory expenses, association dues, and securities expenses. PG&E's A&G forecast reflects an 11% increase over 2011 levels, primarily due to labor escalation, employee training, rate design and analysis, and initiatives to support risk management.

PG&E evaluated 2007-2011 recorded expenses and 2012-2014 forecasts, including vacancy savings; made adjustments and allocations to capital, below-the-line, and affiliates; removed certain incremental costs related to the San Bruno accident; and converted SAP-based estimates to FERC-based estimates.

DRA proposes that PG&E's A&G forecast be reduced as follows: (1) $12.718 million to A&G Department costs; (2) $56.198 million to Company-wide expenses; and (3) $5.778 million in expense and $29.852 million in capital for PG&E's AEOC and IT projects. TURN agrees with DRA in opposing AEOC funding. If the project is approved, however, TURN recommends $6.353 million reductions.

We resolve parties' disputes over A&G costs as discussed below.

9.2. Finance Organization Costs

9.2.1. Finance Department A&G Costs

PG&E forecasts $45.126 million of Finance Department costs, which is 15.1% more than 2011 levels.[96] The Finance Department provides financial capabilities including raising capital, communicating with investors, planning and managing budgets, preparing financial statements and tax filings, and managing payment services for employees and vendors. PG&E's forecasted increase primarily stems from 2011-2014 wage escalation.

DRA recommends a reduction of $351,000 for: (1) external audit fees; and (2) the office of the Vice President, Controller, and Chief Financial Officer (Controller). DRA recommends no funding for the latter item, arguing that PG&E did not describe any ratepayer benefits, and that PG&E claimed to have adjusted out all costs for Account 923 (Outside Services – Corp). TURN recommends a reduction of $61,000 for dues paid to the California Taxpayers Association (CTA) claiming these costs should not be ratepayer-funded as such costs were viewed as a lobbying expense in SCE's 2012 GRC decision. PG&E identifies 10% of dues paid to CTA as supporting lobbying and agrees to a reduction of 10% or $6,100.

Discussion

We adopt PG&E's forecast of Finance Department expense, except for a reduction of $61,000 to exclude 100% of dues paid to the CTA for lobbying as proposed by TURN. We disagree with PG&E's claim that except for a 10% reduction, the remaining CTA dues are a valid utility expense. Our disallowance

of 100% of the dues is consistent with our treatment of CTA dues in the most recent SCE GRC where we concluded that the organization is "focused on tax policy, not delivery of electrical service," and advancing policies of tax reduction is inherently political."[97] Based on similar considerations, we disallow the CTA dues from PG&E's revenue requirements. In all other respects, we find PG&E's forecast of Finance Department costs reasonable.

We decline to adopt DRA's proposed reductions to Finance Department forecasts. DRA's proposed reduction of $261,669 for external audit fees lacks support. DRA's reliance on a three-year historic average does not account for escalation in external audit fees. We also find no basis to disallow Account 923 (Outside Services – Corp) costs for the Controller's office. These costs represent the Controller's labor to support the Corporation. The Controller functions as described in PG&E's testimony are typically required for any company.

9.2.2. Company-Wide A&G Costs

PG&E forecasts company-wide 2014 expenses of $5.098 million in remaining vacation, representing accrued employee vacation leave benefits, and $5.755 million in Bank Fees for depository, disbursement, custodial, and trustee services. No party disputed these forecasts, and we adopt them.

9.2.3. IT Projects

PG&E forecasts $2.56 million expense and $6.275 million capital in 2014 for Finance Organization IT projects, which include Planning Simplification and

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[96] The specific elements of the PG&E forecast of Financial Department A&G Costs together with DRA's forecasts are set forth in the Joint Comparison Exhibit, (Exh. 374) at 2-335.
[97] D.12-11-051, p. 507

Improvement, Automated Close Process, Data Integration and Analysis, and Financial Application and System Updates. PG&E agrees to reduce its capital forecast for 2014 by $1.951 million for the Accounting Convergence IT Project as DRA recommends. PG&E's $6.275 million capital forecast reflects that concession. DRA and TURN both recommend reductions of $358,000 expense and $878,000 capital in 2014 based on the global 14 %reduction related to the Concept Cost Estimating Tool. PG&E opposes this adjustment.

Discussion

We adopt PG&E's forecast for Finance Organization IT Projects of $2.56 million expense and $6.275 million capital, except for a 14% reduction to reflect adoption of DRA's adjustment related to PG&E's use of the Concept Estimating Tool for reasons explained above. In all other respects, we find PG&E's expense and capital forecasts for Finance Organization IT Projects reasonable and beneficial to ratepayers.

9.3. Risk and Audit Department Costs and Insurance Expenses

9.3.1. Department Cost Expense

PG&E forecasts $19.18 million in department costs for 2014 for its Risk and Audit Department, which oversees PG&E's risk management, internal audit, compliance, ethics, and corporate security functions. DRA recommends a $1.09 million reduction to PG&E's $19.18 million forecast for: (1) VP Chief Risk Officer; (2) Enterprise Risk Management (ERM); (3) Corporate Security; and (4) Alternative Company Headquarters (ACHQ). We address these disputes below.

9.3.1.1. VP Risk Officer

PG&E's forecasts $0.227 million in Account 923 (Outside Services – Corp) for the VP Chief Risk Officer. DRA opposes this funding. PG&E's adjustments

to FERC Account 923 - Corp for 2007 through 2011 relate to the reorganization from PG&E – Corporation to PG&E – Utility. These costs are embedded in PG&E's adjusted recorded costs for Accounts 920, 921, and 923 – Utility. DRA claims that PG&E is attempting to burden ratepayers with the consequences of multiple internal corporate reorganizations. DRA recommends that the $0.227 million be removed from test year 2014 forecast.

Discussion

We conclude that PG&E provided reasonable support for its VP Chief Risk Officer forecast which includes consulting, facilities costs, materials, and employee-related internal charges. Because the PG&E Corporation primarily provides support to the Utility, these services benefit PG&E's customers. Accordingly, we find PG&E's forecast of $0.227 million in Account 923 for the VP Chief Risk Officer reasonable and adopt it.

9.3.1.2. ERM

PG&E forecasts $1.632 million in Account 920 (A&G Salaries) for the ERM and Insurance Department. DRA recommends a $0.573 million reduction for the three ERM employees, claiming these additions are not mandated nor justified.

PG&E claims the additional staff in the ERM program support LOB identification and mitigation of enterprise risks. These employees will support the new Operational Risk Management Program and will provide a higher level of risk management support by overseeing top risks and mitigation activities, assisting in creating and monitoring LOB risk assessments, and tracking the LOB progress in implementing mitigation activities.

Discussion

We adopt PG&E's forecast for $1.632 million in Account 920 (A&G Salaries) for the ERM and Insurance Department. We conclude PG&E

reasonably justified this forecast. PG&E's plans for three new employees are based on IRP recommendations that PG&E acquire and develop a staff of professionals with the skills to do state of the art analysis of risk management decisions concerning public and employee health and safety, environmental and socioeconomic consequences, and financial reputation implications.[98] The ERM function promotes safe utility operations and is in line with Liberty's recommendations.[99]

9.3.1.3. Corporate Security

PG&E forecasts $3.170 million in Account 920 (A&G Salaries) for the Corporate Security Department. DRA recommends a $0.123 million reduction related to hiring a Corporate Security Director. PG&E plans to hire the new director before the current director departs. DRA argues that it is unreasonable to include the costs of both directors in PG&E's forecast. PG&E disagrees, and claims doing so is prudent for succession planning.

The Corporate Security Department is responsible for the security of all PG&E facilities to prevent interruption of essential services. Because of the critical nature and importance of this position, PG&E claims the current director must remain to train his replacement based on his experience, and transition the responsibilities to the new director over a period of time.

Discussion

We reduce PG&E's forecast of $3.170 million in Account 920 (A&G Salaries) for the Corporate Security Department to remove $123,000. We make

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[98] Exh. 53 (PG&E-18 v1), Chapter 6, Attachment B (citing IRP Report, Section 5.2.4.1).

[99] Exh. 168 (Liberty), p. S-3 (Item A.2.2); *id.* at S-6 (Item C.1.4).

this adjustment so that ratepayers do not fund labor costs for both a retiring director plus his/her replacement for test year 2014. We do not dispute the importance of the director's function, or the appropriateness of having the retiring director train a replacement for a limited period. PG&E adequately justified the need for continuity in the hiring and training by including overlapping funding for both the retiring director and his/her replacement. Allowing for the retiring director to remain during the training of the new director through the transfer of leadership is important to enhance use of security technology and data analytics in delivery of essential services.

These facts, however, do not justify requiring ratepayers to fund two salaries for one position due to a temporary transitional training process. After the transitional training, the retiring director departs, and PG&E incurs continuing costs only for a single director.

Labor costs for the current senior director of Corporate Security are embedded in 2011 adjusted recorded costs. PG&E's proposed increase for 2013 labor costs of $264,000 includes the anticipated new director. Therefore, the test year 2014 labor forecast includes both the retiring director and his/her replacement. We conclude that test year expenses should reflect continuing expenses for a salary for one director, rather than treating a short-term delay in the retiring director's departure as if it continues indefinitely. We thus adopt DRA's recommendation to remove $123,000 from test year 2014 labor costs to exclude the test year effects of funding a double salary.[100]

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[100] Ex. 39 (PG&E-9, workpapers) at WP 3-75 line 5.

9.3.1.4. ACHQ

PG&E forecasts $250,000 for a feasibility study for the ACHQ. DRA argues that because this feasibility study is a one-time expense, it should be normalized for the test year. DRA thus recommends that $166,667 (two-thirds of the $250,000 expense) be removed from Account 923 (Outside Services – Utility) test year 2014 forecast.

PG&E opposes DRA's recommendation. PG&E anticipates that the expenses for this study will occur in 2014, but other projects in the attrition years are similar in nature. The costs for those attrition year projects are not included in PG&E's forecast and PG&E expects to have some funding in those years carried over from projects like the ACHQ to use to conduct that attrition year work. PG&E argues that normalizing the cost of the study is inconsistent with its post-test year ratemaking proposal.

Discussion

We adopt PG&E's 2014 forecast of $250,000 for a feasibility study for the ACHQ. We do not believe normalization is warranted for an expense of this magnitude which is to be incurred in 2014. In adopting this result, we note that although the cost of this feasibility study gets recovery in 2014, the costs for other feasibility studies in the attrition years are not being charged to ratepayers.

9.3.2. Insurance

PG&E forecasts $104.5 million in insurance costs for 2014. The payment of insurance premiums limits risks of large, unforeseeable loss of utility property due to natural catastrophes. Liability insurance protects against third-party claims alleging bodily injury, property damage, or wrongful acts by PG&E, its Board of Directors, and officers. DRA proposes a reduction of $54.404 million to PG&E's insurance cost forecast covering: (1) non-nuclear property; (2) excess

liability; (3) directors and officers (D&O) liability; and (4) PG&E Corporation property and liability. There is no dispute regarding Nuclear Property Insurance and we adopt PG&E's forecast of $5.191 million for that element. The elements of disagreement over insurance costs between PG&E and DRA are:

($ in millions)

Insurance Item	**PG&E Forecast**	**DRA Reductions**
Corp. Property & Liability (Acct 923)	$0.686	-$0.686
Non-Nuclear Property (Acct. 924)	$21.519	-$3.48
Nuclear Property	$5.191	--
Directors &Officers	$2.845	-$2.132
Other Liability (Acct. 925)	$74.300	-$49.232
Total	$104.548	-$55.1

9.3.2.1. Corporation Property and Liability Insurance

PG&E forecasts $0.686 million for Corporation property and liability insurance. DRA recommends no funding, stating that ratepayers already fund PG&E Utility property and liability insurance, which includes property, D&O, and excess liability insurance. DRA argues that having ratepayers fund these same types of insurance costs for PG&E Corporation is duplication of costs and potential unwarranted subsidy of other non-regulated activities of PG&E Corporation.

PG&E disputes DRA's claim of duplication of costs or subsidization of non-regulated activities, explaining that the Corporation is covered under many of the same policies that cover the Utility. These Corporation costs primarily represent how the Company accounts for the Corporation's share of the total Company insurance costs. According to affiliate accounting rules, PG&E is to

account for these costs to ensure customers do not subsidize unregulated activities.

Discussion

We adopt PG&E's forecast for $0.686 million for PG&E Corporation property and liability insurance, and conclude that the forecast does not duplicate costs. PG&E Corporation does the majority of its work on behalf of the Utility, and 99% of total insurance costs are ultimately paid by the Utility and included in the GRC. No party disputed PG&E's methodology for allocating the Corporation's insurance costs.

PG&E inadvertently included 100% of the Corporation's share of insurance costs in its GRC forecast instead of 99%. To correct that error, PG&E reduced its forecast by $7,000 to $686,000. PG&E's forecast complies with Commission affiliate accounting rules which ensure that the other one percent of Corporation costs is not charged to customers, but to non-utility affiliates.

9.3.2.2. Non-Nuclear Property Insurance

PG&E forecasts $21.519 million for non-nuclear property insurance, which covers the cost of repair and/or replacement of damaged property from perils such as storms, earthquakes, and fires at PG&E's non-nuclear facilities. PG&E's 2014 forecast represents a 42% increase over 2011 levels. DRA recommends a $3.047 million reduction based on using 2012 recorded data as the starting point to determine the 2014 forecast. PG&E responds that though 2012 recorded costs were less than forecast, DRA's recommendation does not consider the effects of catastrophic losses in 2012 and 2013, such as huge losses from Superstorm Sandy, that place upward pressure on insurance rates.

Discussion

We adopt PG&E's forecast of $21.519 million for non-nuclear property insurance. Although the forecast represents a significant increase over 2011 levels, we conclude that PG&E reasonably justified the increase given the increasing value of insured assets and insurance rates that have risen in response to significant property claims resulting from global natural disasters during 2011, which was the costliest natural disaster year on record.[101] We find no basis to rely on 2012 recorded costs given the effects of large losses from natural disasters on increased insurance premiums that are not reflected in 2012 data.

9.3.2.3. Excess Liability Insurance

PG&E forecasts $74.3 million for excess liability insurance in 2014. DRA recommends a $49.081 million reduction. DRA recommends lowering PG&E's forecast by $11.1 million based on the DRA Financial Examiner's recommendation and further reducing the 2014 forecast to reflect 2012 recorded data. DRA also asserts that it is PG&E's burden to show that its forecasted increase in insurance rates does not include effects of the San Bruno accident.

PG&E argues that there is no reasonable way to ascertain what portion of the insurance premium may be attributable to the fact that the San Bruno accident occurred, as opposed to the other factors. PG&E argues that it is not required to remove insurance premium costs to satisfy its burden in this GRC.

DRA forecasts the excess liability insurance forecast based on 2012 recorded data instead of 2011 base year data, and escalates the 2012 recorded amount by 4% each year. DRA notes that a 4% increase annually is slightly

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[101] *See* Exh. 38 (PG&E-9) at 3-12.

higher than the wage escalation rate that PG&E uses in its GRC. No party offered evidence, however, that PG&E's labor escalation rate affects insurance premiums.

Discussion

We adopt PG&E's forecast of $74.3 million for excess liability insurance in 2014. We find lack of support to reduce PG&E's forecast by $11 million, as proposed by DRA.[102] Procuring excess liability insurance is a reasonable business practice. We find insufficient basis to rely on 2012 recorded costs as a basis for 2014 forecasted insurance premium costs. PG&E concedes that 2012 recorded costs were lower than forecast and using 2012 recorded data would result in a lower forecast. As PG&E explains, however, 2012 recorded costs were lower than forecast because in 2012 there was not as much insurance as PG&E wanted to purchase available at reasonable cost in the market, not because of a decreasing pricing trend.

We note that PG&E voluntarily removed certain incremental costs related to the San Bruno accident in this GRC consisting primarily of incremental headcount, outside consulting services, and San Bruno settlements, judgments, and claims.[103] PG&E did not, however, identify or remove insurance premium costs specifically related to the San Bruno accident. Based on the record before us, we find no reasonable basis to identify a specific portion of insurance premiums as being expressly attributable to the San Bruno accident.

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[102] DRA-23,at 5-11; also *see* PG&E's response to DRA Data Request PGE_DRA025, dated 5/22/13, in Appendix A.

[103] *See* Exh. 38 (PG&E-9), at 6-9 and 10.

9.3.2.4. D&O Liability Insurance

PG&E forecasts $2.845 million for D&O liability insurance. DRA recommends a $1.590 million reduction based on: (1) using 2012 recorded data instead of 2011 data as the basis for the base year for the forecast; and (2) reducing the forecast by 50%, in accordance with the policy that such costs be shared equally between ratepayers and PG&E's shareholders.

PG&E claims 2012 recorded data is inappropriate to use for the 2014 forecast. DRA bases its recommendation on its statement that with a downward trend, it is not reasonable to allow a 32% increase in D&O insurance. PG&E discussed in its testimony the factors that explain why that trend is not likely to continue. Prices for D&O liability insurance are at historic lows but are not expected to remain at these levels.

PG&E argues that it's D&O insurance forecast should not be reduced as DRA recommends, and asks the Commission to revisit the policy of sharing of these costs equally between shareholders and customers. PG&E argues that this policy is contrary to cost-of-service ratemaking principles.

In D.12-05-004, the Commission rejected DRA's proposed shareholder cost sharing proposal for SONGS costs, holding that under cost-of-service ratemaking, "[r]easonable costs are entitled to full reimbursement." In rejecting the proposal, the Commission noted that "DRA's recommendation would require a substantial departure from these fundamental principles of ratemaking." PG&E claims that DRA makes a similar recommendation here.

Discussion

We reduce PG&E's D&O insurance forecast by 50%, resulting in a $1.423 million reduction. Past Commission policy of equal sharing of cost responsibility for D&O insurance should continue for this GRC. In situations

such as this, where a corporate service or product offers separate benefits both to ratepayers and to shareholders, imposing cost sharing does not conflict with cost-of-service ratemaking principles. By allowing 50% of such costs for ratepayer funding, we provide reimbursement for a reasonable level of costs attributable to D&O insurance to the extent that ratepayers benefit. It is not reasonable for ratepayers to bear all of the costs related to D&O insurance when a share of those insurance benefits flow to shareholders.

9.3.3. AEOC

PG&E forecasts $19.9 million in capital in 2014 for an AEOC, consisting of $13 million for the building portion and $6.9 million for IT infrastructure. PG&E's primary facilities in San Francisco and the San Ramon Valley Conference Center could become partially or totally unusable for some period of time under certain earthquake scenarios. To mitigate this risk, PG&E plans to establish an AEOC outside the greater Bay Area to provide immediate occupancy for emergency management personnel in the event of a significant seismic event that rendered the existing EOC and AEOC inaccessible or unusable.

DRA and TURN both recommend no funding for the AEOC. DRA's recommendation is based on the fact that PG&E has not yet selected a site for the project. DRA concludes that with no specific site location, estimated construction costs are speculative. TURN does not believe that PG&E can complete this project by the end of the test year. PG&E concedes that completion of this project could extend beyond 2014, but does not believe that possibility warrants eliminating funding, which is designed to mitigate a significant risk.

TURN recommends that if the project is approved, PG&E's forecast be reduced by: (1) lowering construction costs from $575 to $183/sf; (2) reducing

the IT forecast from $16,000 per person to $4,903 per person; and (3 excluding costs for fiber optic cable.

PG&E argues that the lack of a specific site does not impact its forecast except for the amount of fiber optic cable which, at the maximum, represents approximately 15% of construction cost. PG&E provided estimates regarding the number of personnel the facility would accommodate, space per person, construction cost per square foot, and IT equipment costs. PG&E claims it has justified the need for this project as well as cost assumptions used in developing the forecast.

Discussion

We conclude that it is reasonable to include a forecast provision for the AEOC in the 2014 test year in order to mitigate seismic safety risks that could potentially impact emergency operations. Even though PG&E has not identified a specific location for the AEOC, as PG&E notes, uncertainty as to a specific site does not affect the cost forecast except for the amount of fiber optic cable component. We conclude that fiber optic cable should be included in the forecast cost. PG&E supports its forecast of $3 million for fiber optic cable as reasonable. Although there is some uncertainty as to the specific amount of fiber optic cable, no party offered a more accurate fiber optic forecast. We adopt PG&E's fiber optic cable cost forecast.

DRA and TURN also question whether the AEOC will be constructed on schedule. Neither party challenges the need for the AEOC, however, pre-configured with sufficient computer and telecommunications network access, and with space for emergency management and support operations. In the interests of promoting safety, we conclude that funding for the AEOC should be adopted for 2014 to address such an important risk mitigation measure.

Earlier in this Decision, in Section 7, we resolved the dispute between PG&E and TURN regarding construction unit cost assumptions, and applied a 6.7% reduction to PG&E's real estate capital forecast. Accordingly, we adopt a forecast for the AEOC reflecting that adjustment, and reduce the AEOC real estate capital forecast by 6.7%. In all other respects, we find PG&E's forecast of the AEOC reasonable and adopt it.

We conclude that PG&E's forecast of $16,000 per employee for the AEOC is consistent with other new sites with similar technological demands, such as the Vacaville Grid Control Center and the Resource Management Centers. PG&E's forecast reflects AEOC equipment requirements for emergency operation for data transmission systems with redundant paths. These systems need to be redundant to ensure highly reliable and seamless operations during an emergency.

We decline to adopt TURN's AEOC forecast of $4,903 per employee for IT infrastructure costs. TURN's assumptions for IT functionality are based on a mixture of new and existing office spaces. It is inappropriate to apply assumptions representing a mix of new and existing facilities directly to new construction. The per-employee IT cost is more expensive for new construction in contrast to existing facilities, which already have IT infrastructure.

9.3.4. IT Projects for the Risk and Audit Department

PG&E forecasts $4.0 million expense and $13.9 million capital in 2014 for the Risk and Audit Department's IT projects. DRA recommends a reduction of $0.566 million expense and $1.9 million capital to the Risk and Audit Department's 2014 IT forecast. TURN supports this recommendation. The basis

for the recommendation is a global 14% reduction to all of PG&E's IT projects based on use of the Concept Cost Estimating Tool to develop its forecast.

Discussion

We reduce PG&E's 2014 Risk and Audit Department IT forecasts of $4.0 million expense and $13.9 million capital to reflect the 14% reduction based on PG&E's use of the Concept Cost Estimating Tool to develop its forecast. In all other respects, we find PG&E's IT forecast for the Risk and Audit Department reasonable and adopt it.

9.4. HR Department and HR Technology Costs

9.4.1. HR Department Costs

PG&E forecasts $63.5 million for the HR organization in 2014. HR functions to attract, retain, and support a highly-qualified and diverse workforce. The Vice President Human Resources section includes the areas of HR Delivery, Labor Relations, Compensation, and the PG&E Academy.

DRA disputes PG&E's forecasts for HR Delivery and the PG&E Academy, and recommends overall reductions of $7.971 million for: (1) HR Delivery; (2) PG&E Academy; and (3) Talent Management, based on maintaining 2014 staffing and funding for these departments at 2012 levels. DRA's 2014 forecast relies on 2012 recorded employee head count and associated costs in FERC Accounts 920 and 921 escalated by 3% per year for 2 years. DRA claims that this $6.04 million is most reflective of PG&E's current spending. An itemized breakdown of PG&E's capital and expense forecast for the HR Department, as well as DRA's proposed reductions, appears on Table 3-1 and 3-2 of Exhibit (PG&E-24). We resolve these disputes below.

9.4.1.1. HR Delivery

PG&E forecasts $7.7 million for HR Delivery in 2014. PG&E's forecast includes eight additional employees to provide increased field support for supervisors to implement HR programs and ensure compliance with evolving legal and regulatory requirements. DRA recommends a $1.37 million reduction, based on funding this function at 2012 levels. DRA states that PG&E has not provided adequate support or justification for an additional eight employees in 2014.

Discussion

We adopt PG&E's forecast of $7.7 million for HR delivery. We conclude that PG&E's forecast reflects the increased need for HR employees in the field to support leaders in the organization through both incremental hiring and automation of transactions currently performed in the HR service center. PG&E's incremental staffing needs would be greater than forecast if not for freeing up these additional resources. We find no reasonable basis to adopt DRA's use of 2012 recorded data without regard to increased staffing needs relating to the increased HR delivery needs in 2014, as noted above.

9.4.1.2. PG&E Academy

PG&E forecasts $11.7 million for PG&E Academy in 2014, consisting of $5.461 million and $0.616 million in FERC Accounts 920 and 921, respectively, for increased staffing, and $5.607 million in FERC Account 923 for outside service costs to support Technical Training maintenance. The mission of the PG&E Academy is to increase employee safety and productivity by designing, delivering, and measuring top quality in-classroom and online learning. DRA recommends a $4.0 million reduction to PG&E's forecast, consisting of: (1) a $1.9 million reduction across FERC Accounts 920 and 921 to keep staffing levels

for PG&E Academy at 2012 levels; and (2) a $2.1 million reduction in FERC Account 923 for Technical Training maintenance based on 2012 recorded data.

PG&E claims that additional staff for the PG&E Academy is necessary to support increased curriculum oversight and training maintenance. Because PG&E's LOBs are forecasting increased development of new training, PG&E forecasts nine additional staff to provide the instructional design and oversight for that new training. PG&E also forecasts one employee to run the live webcast studio to provide real time training to PG&E employees in remote locations.

DRA claims that PG&E has not shown that the 10 new FTEs for 2014 are needed given staffing increases of 12.5 FTE's in 2012. DRA claims PG&E has not shown that additional staff is needed for the new Webcast Studio and Technical Training maintenance work. For 2014, DRA recommends the 2012 recorded expense of $3.32 million escalated over 2 years.

PG&E agrees that the outside services forecast for Technical Training in FERC Account 923 should be reduced but only by $169,000, and not by as much as DRA recommends. PG&E Academy designs and includes an assessment in each course or curriculum they develop or oversee. DRA recommends a reduction because PG&E uses quality assessments only when it is appropriate to do so, as opposed to in every case.

PG&E does not try to use an assessment in cases where it would be inappropriate to do so, but argues that is not grounds for denying funding to create the assessments in the first instance.

Discussion

We reduce PG&E's forecast by $4 million based on DRA's recommendation to exclude funding for the additional positions requested for 2014. We thus adopt a reduced forecast of $7.7 million for PG&E Academy. We

find PG&E's request excessive in seeking to increase the employee count by another 21.5% from 2012 to 2014, or an overall increase of 66.2% over a three-year period, from 2011 to 2014.

We are not persuaded that such a large increase of 66.2% in staffing over a three-year period is justified in terms of demonstrated ratepayer benefits. Even with this reduction, PG&E will still receive funding for the additional positions hired in 2012 which provides a basis for increasing the effectiveness of PG&E Academy compared with 2011 funding levels.

9.4.1.3. Talent Management

PG&E forecasts $22.0 million for Talent Management, an increase of $4.6 million over 2011 levels. Talent Management is designed to understand future workforce needs, identify and develop PG&E's future leaders, attract and retain the best talent, and maximize employee performance. PG&E requests nine new employees for 2014, based on 2011 staffing levels. PG&E claims that expansion of the knowledge management program will require additional employees; the need for a program manager and project manager in its Leadership Training Program; and for additional workforce planning support due to employee demographics and the need to forecast attrition into the future.

DRA claims that PG&E has not justified adding nine FTE employees in addition to the seven employees added in 2012. DRA recommends a $2.6 million reduction for the nine employees planned to be added for 2014, so that staffing remains at 2012 levels. DRA states that 2012 recorded expense is most indicative of what PG&E is currently spending. PG&E responds that 2012 spending is not a reasonable basis to determine whether the forecast for 2014 represents a reasonable cost of service.

Discussion

While we recognize that this program is useful in attracting and retaining the best talent to maximize employee performance, we find it reasonable to reduce PG&E's requested increase to mitigate the cost burden on ratepayers. We thus reduce PG&E's 2014 forecast for Talent Management to exclude $1.3 million of the requested increase. This reduction represents half of the $2.6 million increase requested for additional employees in 2014. With this reduction, we still fund a reasonable increase over 2011 levels, including staff already hired for this program in 2012. Although PG&E wants to expand the scope of the program beyond 2012 levels, we are not persuaded that potential ratepayer benefits justify the additional cost burden. On balance, we thus temper PG&E's requested increase by approving half of it.

9.4.2. HR Department IT Projects

PG&E forecasts $3.24 million expense and $6.2 million capital for HR Department IT projects in 2014. DRA recommends reductions of $3.04 million expense and $4.8 million capital in 2014. TURN recommends reductions of $306,000 expense and $917,000 capital based on PG&E's use of the Concept Estimating Tool. The elements of HR technology project differences among PG&E, DRA, and TURN are itemized on Table 9-1 of PG&E's Opening Brief.

As a basis for opposition to funding, DRA generally claims that PG&E provides insufficient justification for the projects relating, in particular, to project description, cost breakdown, and customer cost savings, and that PG&E has embedded funding to cover project costs. DRA makes specific recommendations regarding HR Technology Legal and Regulatory, E-Recruit Phase 2, and Onboarding projects. For the IT projects DRA does not oppose outright, DRA

recommends 2014 reductions of $32,000 expense and $224,000 capital based on PG&E's use of the Concept Cost Estimating Tool to forecast project costs.

TURN recommends reductions of $306,000 expense and $917,000 capital in 2014, also on the basis of PG&E's use of the Concept Cost Estimating Tool.

Discussion

We reduce PG&E's expense forecast of $3.2 million by $0.243 million and PG&E's capital forecast of $6.2 million by $0.853 million for HR Department IT projects in 2014, based on PG&E's use of the Concept Estimating Tool to forecast project costs. Throughout this Decision we have acted on DRA's recommendation to adopt a global 14% reduction to IT projects forecasted with the Concept Cost Estimating Tool. In this instance DRA proposed no funding for many of the individual HR IT projects forecasted by PG&E, and only proposed Concept Cost Estimating Tool reductions totaling $32,000 in expense and $224,000 in capital. Our adoption here is reflective of TURN's proposal, in which 14% reductions are applied globally to all HR IT projects forecasted with the Concept Cost Estimating Tool. However, our adopted reductions differ slightly from TURN's proposed reductions due to various updates to PG&E's forecasts. In all other respects, we find PG&E's HR Department IT capital and expense forecasts reasonable and adopt them.

PG&E included IT project summaries in workpapers with information regarding the need for and capabilities of the projects. PG&E estimated most technology projects using the Concept Estimating Tool. For each project estimated using the Concept Estimating Tool, PG&E provided a breakdown of costs. We recognize that PG&E's HR Technology projects are not necessarily designed to provide customer cost savings. Many projects address compliance items to meet legal and regulatory obligations. Others improve the ability to

provide employee information to managers and also to regulators, or to allow for increased use of technology to make HR processes more effective.

We conclude that PG&E reasonably justified its forecast of HR Technology Legal and Regulatory. As an example of the type of change under this project, PG&E referenced the new Office of Federal Contract Compliance Programs (OFCCP) regulations. DRA criticizes PG&E's showing that this was the only information provided about this project. PG&E, however, provided additional examples of legal and regulatory updates to its HR systems in 2010 and 2011. Laws and regulations continually change. PG&E needs to update its HR systems to reflect these changes. PG&E cannot predict with certainty which laws or regulations will change from 2014 through 2016 or the precise cost associated with not complying with those changes.

We accept PG&E's forecast for the E-Recruit project. DRA proposes no funding for this project claiming that PG&E is already receiving benefits of the E-Recruit project implemented in 2012 and another round of enhancements is excessive and burdensome to ratepayers. Although the first phase of the E-Recruit project is providing benefits, those benefits are different than what will be provided through the second phase. The initial phase included deployment of new technology and recruiting processes which provided process improvements and improved compliance with OFCCP regulations. In Phase 2, PG&E will automate Affirmative Action Plans and reporting as well as the offer letter process. Benefits provided by the second phase of this project are necessary to realize the full potential of the technology, and to build on those developed in the first phase.

DRA recommends no funding for the onboarding project and sees no reason for a specific employee portal, arguing that job bulletins and forms can be

sent through e-mail. As PG&E responds, however, e-mail cannot securely transmit sensitive information such as social security numbers. Transmission of such information via e-mail exposes the new employee to possible identity theft. PG&E also considers benefit plan elections to be Health Insurance Portability and Accountability protected data, which should not be transmitted through e-mail.

DRA believes that since PG&E deferred this project for this rate case, it is not a priority. PG&E disputes DRA's contention, arguing that the project was deferred in favor of addressing a compliance issue related to PG&E's applicant tracking system. This project is important given the increased level of PG&E hiring.

Subsequent to filing the GRC application, PG&E accelerated a key component of the Employee and Manager Self Service project—specifically, the integration of the SAP portal with the SAP back-end, eliminating the need for the HR Service center to reenter data for many transactions. PG&E disagrees with DRA's recommendation not to fund this project. PG&E also proposes to reduce the Workforce Health and Productivity Service Delivery project funding to 10% of that presented in the application, for a total forecast of $48,000 expense and $240,000 capital in 2014. This is a reduction of $92,000 expense and $460,000 capital. Although project scope has not changed, the project schedule was accelerated and 90% of the work was expected to be completed by 2013.

9.5. Regulation and Rates Department

PG&E forecasts $22.467 million in Regulatory Relations department costs for 2014. The Regulatory Relations Department provides regulatory expertise, assisting in PG&E's overall strategy development and managing regulatory cases. DRA recommends reductions of $1.363 million relating to salaries (Account 920) and outside service costs (Account 923). TURN supports DRA's

recommended reductions, and also recommends a reduction regarding dues for the California Council for Environmental and Economic Balance (CCEEB) organization. TURN recommends that the FERC and ISO Relations Department's (Provider Cost Centers 12864 and 12916) total forecast cost be allocated 100% to the generation LOB. We address these disputes below.

9.5.1. A&G Salary Increases (Account 920)

PG&E forecasts $15.412 million in Account 920 (A&G Salaries) for the Regulation and Rates Department. At the end of 2012, the Regulation and Rates Department consisted of 130.4 FTEs. PG&E plans to hire nine incremental staff in 2014. In the Analysis and Rates department, PG&E plans to hire five employees consisting of three Senior Regulatory Analysts to design gas and electric rates and provide policy support, and two employees (one Specialist and one Senior Regulatory Analyst) to develop revenue requirements and perform cost analyses. In the Operations Proceedings Department, which manages virtually all aspects of PG&E's regulatory proceedings, PG&E plans to hire three Senior Case Managers and one Case Coordinator to support increases in the number of regulatory filings.

DRA proposes a reduction of $1.353 million for nine additional employees in the Regulatory Department. TURN supports DRA's proposal. DRA claims PG&E has shown no immediate need or urgency to hire these new employees, especially when this department already added nine FTE's in 2012. DRA claims that PG&E has been operating sufficiently with the current staff levels.

PG&E claims it needs nine additional employees to manage a growing regulatory caseload and to perform increasingly complex rate design and analyses. PG&E claims a need for these employees to manage an increasing number of regulatory filings, data requests, and mandated compliance

requirements, as is evident in the scale of general discovery and the audit conducted in this GRC proceeding. In addition to the growing workload volume of the GRC, PG&E claims there has been an increase in the number of regulatory filings that include revenue requirement and/or rate change proposals produced by PG&E's Analysis and Rates Department. PG&E notes that while DRA disputes PG&E's need for increased staffing needs to deal with regulatory workload complexities, DRA also appears to be requesting additional staff to accommodate expanding regulatory workload.[104]

PG&E claims that its forecast for the employees is $900,000, not $1.353 million as DRA claims. The $1.353 million DRA references consists of $0.9 million for the nine incremental positions, and $0.4 million wage escalation for existing staff.

Discussion

We reduce PG&E's forecast for Account 920 (A&G Salaries) for the Regulation and Rates Department by $900,000 to exclude funding for nine additional staff. In all other respects, we conclude that PG&E justified its 2014 forecast for Account 920 Regulation and Rates Department. We appreciate that regulatory filings have become increasingly voluminous and complex in recent years. As DRA notes, however, PG&E already hired nine new employees in its Regulation and Rates Department in 2012. While PG&E generally describes the increasing complexity and volume of regulatory workload in recent years, PG&E does not adequately delineate why new employees hired in 2012 were not

[104] Exh. 63 (PG&E-24), at Fiscal Review Subcommittee No. 2 on April 25, 2013, DRA has requested five new positions to keep pace with increasing workload.

sufficient to address and relieve generally increasing workload demands in recent years.

In evaluating PG&E's claimed need for more staff, we conclude that PG&E has not adequately delineated impacts of prior staff increases in relation to the nine additional employees requested for 2014 to handle regulatory workload. We are not persuaded that PG&E requires the additional staffing to carry out its regulatory duties through this GRC cycle. While more staff would enable PG&E to process increased regulatory workload faster, it is not clear that any additional benefits in terms of regulatory workload processing justify burdening ratepayers with paying for more regulatory staff overhead. Also, without a comparison of DRA's regulatory resources and needs to those of PG&E, we find no basis to conclude that any DRA request to increase its own staff necessarily has any bearing on the merits of PG&E's requested staffing increases.

9.5.2. State Agency Relations Department

PG&E forecasts $532,444 in Account 923 (Outside Services) for the State Agency Relations Department in 2014. DRA recommends a $120,000 reduction for ongoing consulting expenses. We conclude that these costs are for a legitimate business purpose. This budget item relates to external consultant work associated with AB 32 requirements for climate change mitigation and reducing greenhouse gas emissions.

9.5.3. CCEEB

TURN proposes a $133,624 reduction to PG&E's 2014 Regulatory Relations forecast related to PG&E's costs for the CCEEB. TURN argues that the CCEEB is heavily involved in lobbying and support of legislation and initiatives, and thus ratepayers should not pay related costs.

PG&E estimates that approximately $75,500 of the 2014 forecast relates to the State Agency Relations Department. CCEEB participates in a number of functions, only a fraction of which are categorized as lobbying. The CCEEB conducts an annual internal audit to determine the percentage of its dues used for lobbying and thus not deductible as a business expense. Of the $123,000 of CCEEB costs recorded in 2011, $69,500 of which pertained to the State Agency Relations Department costs referenced in TURN testimony, the CCEEB determined that 13% of dues were lobbying in nature and thus not deductible. On this basis, PG&E agrees that 13% of estimated 2014 charges relate to the State Agency Relations Department, or approximately $9,815, should be removed from the 2014 forecast for the State Agency Relations Department.

Discussion

We adopt TURN's proposal to exclude the entire $133,624 in 2014 related to PG&E's costs for the CCEEB activities. We are persuaded by TURN that PG&E's limited exclusion of 13% of CCEEB dues for lobbying costs is too narrow, and doesn't account for the other public advocacy activities of CCEEB. We agree that ratepayers should not pay for political advocacy conducted by the CCEEB with which they may not agree.

9.5.4. Regulation and Rates IT Projects

PG&E forecasts $1.6 million expense and $2.2 million capital in 2014 for three Regulatory Relations IT projects: (1) the RO Infrastructure project; (2) the Rate Design and Analysis Infrastructure project; and (3) the Enhancing Regulatory Relations Operations Tools project.

PG&E forecasts the RO Infrastructure Project as the next phase following the RO Data management Project, which established a data management system that replaced individual and independent source files. In the RO Infrastructure

Project, PG&E will enhance the expense and capital RO model integrated with the data management system and PG&E's financial SAP system. PG&E forecasts $150,000 expense and $600,000 capital for this project in 2014. DRA recommends reductions of $1.471 million in expense and $1.684 million in capital to PG&E's overall 2014 Regulatory Relations IT project forecasts. DRA recommends that the capital portion of the forecast for the RO Infrastructure project be reduced by 14%, based on PG&E's use of the Concept Estimating Tool to forecast the project costs, and recommends that the expense portion be removed. DRA recommends no ratepayer funding for the Rate Design and Analysis, and Enhancing Regulatory Relations Operations projects.

PG&E forecasts $400,000 expense and $1.6 million capital for the Rate Design and Analysis Project to meet the increasingly complex modeling demands of revenue allocation and rate design. The project includes upgrading infrastructure to incorporate the use of interval data made possible by SmartMeter™ technology and automation of data flow. The Analysis and Rates department use Microsoft Excel to model rates for regulatory proceedings. With the addition of SmartMeter™ interval data to inform rate design, Microsoft Excel alone lacks the ability to effectively manage the volume of data without the support of a technology platform. Given the volume of interval data, this project will provide capabilities to support regulatory proceedings, explore alternative rate design, and respond to an increasing number of data requests and mandatory compliance requirements in a timely manner. The infrastructure will also be used for Energy Efficiency and Demand Response program management, measurement and valuation, and carbon emissions reporting to local governments.

DRA proposes no funding for this project, arguing that PG&E has always had a budget for rate design and should pay for the project with embedded funding. If this is a new type of cost, DRA states that Ordering Paragraph 37 in the Commission's decision on PG&E's last GRC requires PG&E to estimate and include revenue requirement cost savings achieved by the new type of cost or an explanation of the reasons there will be no cost savings. DRA claims that PG&E's Direct Testimony fails to meet either requirement, and PG&E's Rebuttal Testimony comes too late to verify. DRA, therefore, recommends no ratepayer funding for this project.

PG&E responds that this project does not represent a new type of cost, but makes improvements to rate design and analysis processes replacing obsolete Excel models, creates a central repository to store inputs and outputs, and automates data output.

PG&E forecasts $1.05 million expense in 2014 for the Enhancing Regulatory Relations Operations Tools project, composed of: (1) Tariff Manager 2 (TM2) Replacement; and (2) Enhancements to the netTools suite and WebDocs. PG&E claims Tariff Manager 2 is a necessary tool for automating the publication of tariffs and filed advice letters onto PG&E's Webpage in compliance with General Order 96-B.326/TM2 is approaching the end of its technological lifespan and needs to be replaced. DRA recommends no funding for this project.

Discussion

We adopt PG&E's forecast of $1.6 million expense and $2.2 million capital in 2014 for three Regulatory Relations IT projects, except for a 14% reduction to reflect DRA's adjustment for use of the Concept Cost Estimating Tool. We do not, however, adopt DRA's proposed denial of funding for the Rate Design and Analysis and Enhancing Regulatory Relations Operations IT projects. The Rate

Design and Analysis Project addresses the increasingly complex modeling demands of revenue allocation and rate design. We conclude that there is no embedded funding to pay for the planned increases in program scope. PG&E has adequately supported the project, which provides infrastructure to support effective use of massive volumes of interval data in rate design and in other analyses.

PG&E reasonably justifies the NetTools Suite and WebDocs as a central part of its regulatory records compliance tracking, time reporting, and project tracking. This project provides maintenance, upgrades, and enhancements to those tools. The project does not necessarily yield cost reductions, but it does replace obsolete technology, provide maintenance and updates to existing technology, and ensure that PG&E maintains adequate tools to manage regulatory records, support project tracking, and time reporting. We find PG&E's justification for this project reasonable.

9.5.5. Allocation of FERC and ISO Relations Department Costs

PG&E forecasts $829,831 for the FERC and ISO Relations Department in its Test Year 2014 GRC. The FERC and ISO Relations Department supports PG&E's Electric Transmission, Energy Procurement, Power Generation, and Gas Transmission Lines of Business. TURN does not dispute the cost amount. However, given that FERC and ISO relations are only related to transmission and generation, and not distribution, TURN proposes that this expense should be directly assigned to transmission and generation at 50% each, with none allocated to distribution.

We conclude that TURN's recommended allocation is reasonable, and thus adopt it.

9.6. Law Department and Related Costs

9.6.1. Department Cost Expense

PG&E forecasts department costs of $51.7 million for the Law Department, General Counsel's Immediate Office, and Information Management Compliance Department in 2014, which is a reduction of 5.6% from 2011 recorded levels. No party disputes PG&E's Law Department costs 2014 forecast. We adopt PG&E's $51.7 million 2014 forecast for the Law Department.

9.6.2. Settlements, Judgments, and Claims

PG&E forecasts two types of costs in Account 925 – Injuries and Damages: (1) settlements and judgment costs, as part of litigation, and (2) claims payments to third parties alleging personal injury, property damage and economic loss as a result of PG&E's operations. PG&E forecasts $21.0 million for settlements and judgments, and $14.9 million for third-party claims payments. None of the settlements and judgments used to calculate PG&E's 2014 forecast pertains to the San Bruno accident. Such costs were removed as part of PG&E's GRC forecast. PG&E's 2014 forecast for Litigation/Settlements and Third Party Claims expenses is a 24.39% increase from 2011 levels. PG&E calculated its settlements and judgments forecast based on a four-year average of adjusted actual costs for 2008-2011, which is the same methodology PG&E proposed in its 2011 GRC.

DRA recommends a reduction of $1.467 million, consisting of $1.228 million to PG&E's settlements and judgments forecast and $239,000 to PG&E's third-party claims forecast. DRA recommends that costs related to employment and discrimination cases be removed before forecasting for the Test Year 2014. DRA references FERC Accounting Release 12 (AR-12), issued in 1980, which states that costs related to employment and discrimination cases should be removed before forecasting Test Year expenses.

PG&E responds that AR-12 addresses only discriminatory employment practices, but does not address employment litigation where there is no claim of discrimination. DRA confirmed that, if the Commission were to allow recovery of PG&E's employment-related, but not discrimination-related, settlements, DRA's proposed reduction to PG&E's forecast would be $1.228 million.

PG&E responds that the Commission has applied AR-12 to settlements in other cases, but has not applied such a standard to PG&E. PG&E claims DRA's recommendation conflicts with the treatment of reasonably incurred employee settlements and judgments adopted in D.83-12-068, which allowed recovery except for expenses where PG&E had to pay punitive damages or where the court found that PG&E acted in bad faith. PG&E affirms that none of the settlements and judgments used in its current forecast includes punitive damages or a court finding of bad faith.

Discussion

We adopt PG&E's 2014 forecast of $21.0 million for settlements and judgments, and $14.9 million for third-party claims payments. We find no basis to reduce PG&E's forecast based on DRA's claim that employment and discrimination cases should be removed before forecasting Test Year expenses. None of the settlements and judgments used in PG&E's 2014 forecast includes punitive damages or a court finding of bad faith. Thus, there is no basis to reduce the forecast consistent with the policy adopted in D.83-12-068. Based on this ratemaking treatment, PG&E is responsible to exercise its best professional judgment to resolve employment cases in the most cost-effective manner possible, whether through settlement or litigation.

9.6.3. Law Department IT Projects

PG&E forecasts two Law Department IT projects for 2014-2016. The first is the Legal eDiscovery program, for which PG&E forecasts $276,000 in expense and $800,000 in capital for 2014. The second is the Public and Employee Safety and Claims Management Program, for which PG&E forecasts $388,000 in expense and $90,000 capital in 2014. DRA and TURN propose reductions of $39,000 expense and $112,000 in capital for the Legal eDiscovery program. DRA and TURN propose reductions of $54,000 expense and $13,000 capital for the Public and Employee Safety and Claims Management Program. Their recommendations are based on DRA's global recommendation, supported by TURN, to reduce IT project costs forecasted using the Concept Cost Estimating Tool by 14%.

Discussion

We reduce PG&E's Law Department IT project costs by 14% to reflect DRA's adjustment based on forecasts using the Concept Cost Estimating Tool. In all other respects, we adopt PG&E's IT Project forecasts for the eDiscovery and Public and Employee Safety and Claims Management Programs. These IT programs will enable PG&E to perform Law Department duties more efficiently. The eDiscovery program will expand PG&E's in-house capabilities to do discovery of electronically-stored information by increasing the number of software licenses and procuring an Early Case Assessment tool to improve control and visibility of eDiscovery program costs. The Public and Employee Safety and Claims Management Program will improve the efficiency of gathering information on customer claims by providing investigators with mobile devices for capturing claims-related information.

9.7. PG&E Corporation and Executive Offices; Corporate Secretary Dept. Costs

9.7.1. Department Cost Expense

PG&E forecasts $13.8 million in 2014 department costs for its Executive Offices and Corporate Secretary. PG&E's Executive Offices include the office of the PG&E Corporation's Chairman of the Board, Chief Executive Officer (CEO) and President, and the office of the Utility President.

DRA recommends a reduction of $1.9 million to PG&E's forecast for the office of the CEO and the office of the Utility President. PG&E forecasted the department costs for these offices using base year recorded data. DRA proposes a forecast methodology using an average of recorded costs for 2010-2012. PG&E claims DRA provided no basis for its methodology other than the fact that doing so would result in a lower number.

Discussion

We adopt PG&E's 2014 forecast of $13.8 million in 2014 department costs for its Executive Offices and Corporate Secretary as reasonable. PG&E forecasted the department costs for these offices using base year recorded data. DRA identified no methodological deficiencies in PG&E's forecast, and has not provided a convincing rationale for reducing PG&E's forecast by $1.9 million based merely on use of 2010-2012 recorded costs.

9.7.2. Director Fees and Expenses

PG&E forecasts $1.617 million for Director fees and expenses in 2014. PG&E's forecast is 3.2% higher than the 2011 costs, and 5% less than in 2011 in base year dollars. DRA recommends reductions of $324,301 in the following areas: (1) Director retainers; (2) Board and Committee Fees; and (3) Director expenses.

PG&E forecasts $876,000 for Director retainers in 2014. DRA recommends a $216,000 reduction including $66,000 for quarterly retainers and $150,000 for additional retainers. DRA claims that Directors' quarterly retainer payments should remain at 2009 levels and no further increase has been justified.

PG&E explains that the Boards of PG&E Corporation and the Utility each establish the level of compensation for that Company's non-employee directors, based on recommendation of the PG&E Corporation Compensation Committee. PG&E argues that the basis for setting the amount of Director retainers is reasonable and consistent with market practice. PG&E states that DRA provided no justification for its $150,000 recommended reduction for additional retainers.

PG&E forecasts $523,000 in Board and Committee meeting fees. DRA recommends a reduction of $31,667 for committee fees based on substituting a three-year average in place of PG&E's forecast.

PG&E forecasts $218,000 for Director expenses in 2014. DRA recommends a reduction of $76,635, to: (1) remove $42,821 for expenses related to tips, transportation costs, outside speakers, education for Directors, and candidate interviews for PG&E positions that DRA claims are unreasonable and excessive; and (2) use a three-year average plus escalation to calculate the forecast.

PG&E claims that DRA has not shown that these expenses are unreasonable or excessive, nor justified substituting its forecast methodology for PG&E's, other than by doing so results in a lower number.

Discussion

We adopt PG&E's forecast of $1.617 million for Director Fees and expenses in 2014. We are not persuaded by DRA's claims that PG&E's forecast of these costs is unreasonable or excessive. Reimbursement of Board expenses for items such as tips, transportation costs, outside speakers, education for Directors, and

candidate interviews for PG&E positions is a standard business practice. We conclude that the forecasted level of PG&E's 2014 Director Fees and Expenses is reasonable and is lower than 2011 costs in base year dollars.

9.8. Corporate Affairs – Communications Department Costs

9.8.1. Department Cost Expense

PG&E forecasts $18.957 million in department costs for the Corporate Affairs – Communications Department, which informs and educates customers on multiple aspects of PG&E service; supplies information during emergencies; raises customer awareness of utility programs, pricing, service options, and customer offerings; responds to media inquiries; and keeps stakeholders apprised of key changes to PG&E's operations in their local communities, especially as related to public safety.

TURN proposes a reduction of $444,000 for ongoing expenses associated with operation and maintenance of PG&E's Currents website and Next 100 blog. TURN's proposed disallowance accounts for 50% of the total website expense since PG&E has already voluntarily allocated the other 50% to shareholders. TURN claims that these websites are the modern day counterpart to the old printed bill insert, PG&E Progress, which was provided to customers at PG&E shareholder expense because it presented PG&E views on controversial issues and polished PG&E's public image. TURN argues that these websites serve the same purpose as the former PG&E Progress, and thus PG&E's shareholders should likewise pay the full cost of the website.

PG&E does not dispute that some content on the website is editorial, but notes that the website also includes information about PG&E's products, services and programs for customers. For that reason, PG&E believes customers and

shareholders should share the cost of its continued operation evenly. PG&E already allocated 50% of the costs of the Currents website below-the-line to shareholders in its 2014 forecast.

Discussion

We reduce PG&E's forecast for 2014 for the Corporate Affairs - Communications Department by $444,000, based on adoption of TURN's proposed disallowance of the remaining 50% of ratepayer costs for PG&E's Currents website and Next 100 blog. In all other respects, we find PG&E's Corporate Affairs – Communications Department forecast reasonable and adopt it.

We disallow the $444,000 based on rejection of PG&E's proposed 50/50 sharing of costs for PG&E's Currents website and Next 100 blog between customers and shareholders. As noted by TURN, customers already pay for PG&E's primary website, which provides consumer information regarding rates, tariffs, Energy Efficiency programs, safety, reliability, service initiation, etc. We do not believe customers should have to contribute toward other PG&E web sites as well. While certain information on PG&E's second web site may present certain articles of interest to customers, PG&E has not delineated what portion of the web site is devoted to necessary customer information. In any event, we are not persuaded that customers require a second web site whose purposes appear to be largely for promoting PG&E's public image and shareholder perspectives. Customers' needs for on-line information can adequately be met through PG&E's primary website.

9.8.2. IT Project Expense and Capital – Digital Channel Optimization Project

PG&E forecasts $250,000 in expense and $750,000 in capital in 2014 for the Employee Digital Channel Optimization project. This project provides business-related social media and video communications tools to allow employees to communicate quickly and effectively with Company experts, team leaders, and coworkers, thereby improving public and employee safety and increasing productivity and quality of performance. DRA proposes no funding for the project, stating that PG&E did not quantify ratepayer cost savings or perform a cost benefit study. TURN recommends reductions of $35,000 in expense and $105,000 in capital based on PG&E's use of the Concept Cost Estimating Tool.

Discussion

We reduce PG&E's 2014 forecast of $250,000 in expense and $750,000 in capital by 14% to reflect PG&E's use of the Concept Cost Estimating Tool to develop its forecast. In all other respects, we find PG&E's proposal for the Employee Digital Channel Optimization project reasonable and adopt it. We conclude that PG&E has justified this project's potential to increase the effectiveness of PG&E employee communications in the field so they can work safer and smarter. PG&E implemented these technologies on a pilot basis, which has shown it to be effective and extensively adopted by employees across the Company.

9.9. Corporate Affairs – External Department Costs

PG&E forecasts $10.4 million in department costs for the Corporate Affairs – External Department. External affairs informs, advises and assists stakeholders within PG&E's service territory and in Washington, D.C. on key matters related to the delivery of safe and reliable gas and electric service. PG&E's 2014 forecast

is $135,000 higher than the 2011 recorded adjusted amount of $10.2 million. The increase is attributed to wage escalation. No party disputed this forecast, and we adopt it.

9.10. UCC and Allocation Issues

No party takes issue with PG&E's methodology for forecasting allocations to capital, below-the-line, or non-utility affiliates. TURN and MEA have raised issues regarding the unbundling of A&G expenses to Electric Distribution, Gas Distribution, Generation, and other UCC for this GRC or other proceedings. TURN also proposes a change in unbundling costs of the Regulatory Affairs organization.

PG&E allocates costs to utility functions using UCCs. These residual costs include Corporate Services Administration and General Expenses. MEA recommends removal of the PPP's labor from PG&E's current A&G overhead allocation methodology. TURN disagrees with MEA's proposal and, instead, requests that the incremental A&G costs of PPP programs be unbundled and charged to PPP programs.

MEA, TURN and PG&E jointly filed a motion on September 6, 2013, and a subsequent correction in a Motion to Reopen Record on March 18, 2014 to approve a partial settlement that resolves this issue for purposes of the GRC. In that partial settlement, the parties agree to a method allocating a portion of A&G expenses from Distribution to Customer Program revenues. Specifically, the parties propose that costs associated with certain employee benefits that are currently allocated to Distribution and recovered in the GRC revenue requirement be reallocated to Customer Programs and the balancing accounts attributable to the Customer Programs. This would reduce the GRC revenue requirement by approximately $28.8 million and increase the revenue

requirements for the Customer Programs in an equal amount. If the Commission for any reason declines to adopt parties' partial settlement agreement, PG&E's asks that its proposed allocation of these costs be adopted as set forth in its rebuttal testimony.

Discussion

The only party to object to the parties' proposed settlement of PPP issues was EPUC. We find no basis to reject the settlement based on the opposition filed by EPUC. EPUC objects to the settlement based on the claim that by resolving PPP issues, the settlement addresses a revenue allocation issue that belongs in PG&E's GRC Phase 2 proceeding. Yet, while EPUC objects to the settlement on this basis, EPUC did not raise similar objections to parties' underlying testimony which addresses the same cost issues that the settlement would resolve.

EPUC never moved to strike any of the underlying testimony on PPP cost issues based on objections that the issues raised therein were outside the scope of this proceeding. Thus, the settlement merely resolves issues already addressed in parties' underlying testimony and which no party, including EPUC, moved to strike. Thus, granting EPUC's request would merely defeat the proposed settlement, while the underlying testimony addressing similar issues regarding PPP treatment would still require resolution.

Also, the settlement does not address "factors used to allocate Customer Program revenue requirements to customer classes."[105] Thus, in PG&E's GRC Phase 2 proceeding, EPUC or any other party will be free to present proposals

[105] Partial Settlement Agreement, Section IV, E.

regarding the factors to use to allocate Customer Program costs among customer classes. Given these considerations, we find no basis to deny approval of the settlement. On the other hand, we conclude that the settlement results in a reasonable resolution of the disputed issues that reflects a balancing of the affected interests. We grant the parties' joint motion to approve the partial settlement that resolves this issue for purposes of the GRC, whereby the parties agree to a method allocating a portion of A&G expenses from Distribution to Customer Program revenues. Accordingly, we hereby adopt the settlement as set forth in Appendix F-3. We incorporate the joint party settlement's provisions in our adopted RO.

9.11. Miscellaneous Promotional Items

TURN proposes a reduction of $199,000 in PG&E's test year A&G expense forecast to remove the effects of promotional and image-building items.[106] PG&E spent $183,265 on clothing and other gear containing PG&E's name and logo(excluding uniforms, hard hats, etc.) in base year 2011, as shown in TURN DR 49-02.

TURN argues that these types of expenses are promotional and image-building (i.e., giveaways and other materials) that should not be paid for by ratepayers. TURN calculates that the applicable adjustment to expenses, escalated to 2014 dollars, as $199,000. TURN proposes that this amount be disallowed as A&G expenses, spread across all PG&E units, and unbundled by labor to functions.

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[106] Ex. 116 (TURN, Marcus Testimony), p. 63; TURN Opening Brief, p. 297.

Discussion

We conclude that TURN's proposal is reasonable and accordingly adopt a reduction of $199,000 in PG&E's test year A&G expense forecast to remove the effects of promotional and image-building items, as noted in TURN's testimony. Since such promotional and image-building items do not provide any apparent benefit in the provision of retail service to ratepayers, we find no basis to approve ratepayer funding of such costs.

10. Results of Operations (RO)

To derive the adopted revenue requirements for PG&E's 2014 Test Year and 2015-2016 attrition period, we utilize the RO computer model. The RO model compiles all cost and revenue estimates to produce the Summary of Earnings Report which reports the calculated revenue requirement of PG&E's Lobs. In this section, we address parties' disputes relating to the treatment of certain items used to derive the Summary of Earnings Report generated by the RO model.

The RO model was run incorporating the amount adopted in this Decision. PG&E's Summary of Earnings is found in Appendix C of this Decision. As a result of the adjustments adopted and run through the RO model, the test year 2014 revenue requirement for PG&E is adopted as summarized at Appendix C, Table 1. The adjustments that we have made to the RO model resulting in the aforementioned revenue requirements are hereby adopted by the Commission. The adopted revenue requirements in corporate all of the 2014 test-year forecasts for PG&E's various lines of operations discussed in this decision, and are set at the level necessary for PG&E to provide its customers with safe and reliable service at just and reasonable rates. In this section, we resolve parties' disputed issues relating to the ratemaking conventions applied in running the RO model.

10.1. Treatment of Tax Deductions

PG&E forecasts a 2014 provision for income taxes and deferred tax balances in its gas and electric distribution and generation services based on PG&E's forecasted expenditure estimates as applied to state and federal tax laws. The parties did not dispute PG&E's overall methodology, but DRA and TURN raised issues concerning PG&E's tax forecast assumptions for ratemaking purposes.

10.1.1. Tax Deductions for Employee Stock Option Plans

TURN raises a tax policy issue associated with treatment of the special deduction for common stock dividends paid by PG&E Corporation to participants in PG&E's 401(k) plan who choose to hold PG&E Corporation stock. This issue is referred to as "the Employee Stock Option Plan (ESOP) Deduction. TURN proposes a reduction in ESOP tax expense of $16.788 million.[107]

PG&E Corporation operates an ESOP, which is a tax advantaged way of allowing employees to own shares of PG&E stock on a group basis. Employees may make contributions to PG&E's Savings Fund Plan. If they choose to contribute, PG&E matches 75% of their contributions up to 6% of their salary in PG&E Corporation stock. Employees (and retirees) may invest contributions in PG&E Corporation stock or in virtually any publicly traded security or mutual fund. To the extent that employees invest in PG&E Corporation stock, they participate in the ESOP. Dividends received within the ESOP are automatically

[107] Exh. 116 (TURN-Marcus), at 75, Table 35. The total amount at issue including gross up is $23.363 million.

reinvested in PG&E Corporation stock. These dividends give rise to a tax deduction, which is the source of the dispute among the parties.

TURN recommends that the ESOP dividends be recognized as a source of tax deduction for ratemaking purposes (specifically the portion of the tax deduction allocable to funds associated with utility employees). TURN argues that assigning ratepayers the benefits relating to the ESOP tax deduction is equitable because ratepayers fund the employee wages that can be used for ESOP contributions. Dividends paid by a corporation to an ESOP are a tax deduction for the dividend payer. Under PG&E's proposal, however, the deduction is instead flowed to all of its shareholders, ESOP participants and other shareholders alike. Participating employees receive no explicit benefit from the existence of the tax deduction. Ratepayers also pay for the employer matching contribution to ESOP as part of PG&E's Retirement Savings Plan.

TURN argues that the payment of ESOP dividends, which give rise to tax benefits, differs from other expenses that give rise to tax deductions provided to shareholders, such as political activities, dues, charitable contributions, and institutional or public relations advertising for which the Commission specifically disallows ratepayer funding.

Shareholders fund the cost for dividends paid by PG&E Corporation on stock held within the savings fund plan. TURN disagree with PG&E as to how the tax deduction for these costs should be assigned between shareholders and ratepayers.

Discussion

We conclude that PG&E's ratemaking treatment of income taxes relating to the ESOP deduction is reasonable. Thus, we decline to recognize the ESOP

dividends as a source of tax deduction for ratemaking purposes, as proposed by TURN.

The deduction arises when PG&E Corporation declares and pays a general common dividend out of retained earnings, and the dividend is received on PG&E Corporation stock in which the employee (or retiree) has decided to invest and hold within the Savings Fund Plan. The deduction does not arise from the employee's wages or when PG&E matches employee contributions to their 401(k) plans, as those deductions are reflected in rates.

The Commission's rulemaking on income tax expense for ratemaking purposes (D.84-05-036 or OII 24) adopted an approach for forecasting income tax expense for ratemaking purposes. This method generally provides that only expenses included in the cost of service are considered in matching deductions for those expenses used in forecasting income tax for ratemaking purposes.

The Commission also determined that when deductions were not part of utility cost of service, but were generated with shareholder funds, the deductions are the property of shareholders and not ratepayers. This included deductions derived from disallowed costs incurred in excess of those included in rates, as well as deductions for discretionary uses of net earnings by shareholders. A plan participant's decision to voluntarily invest in a manner that generates a special tax deduction is thus not part of the ratemaking process.

TURN argues that the ESOP is distinguishable from other items where deductions are provided by shareholders, such as political activities and donations, because ratepayers paid the wages that gave rise to the workers' contributions as well as employers' savings funds matching contributions. As noted by PG&E, however, the tax deduction does not arise out of payment of employee wages or matching retirement contributions. Rather, the ESOP

deduction arises when the Board of Directors of PG&E Corporation exercises discretion to distribute retained earnings by disbursing a stock dividend. Retained earnings are shareholder property. As determined in OII 24, tax benefits derived from discretionary disbursements by the Board of Directors out of retained earnings belong to shareholders, not ratepayers. Consistent with D.84-05-036, "the Commission should not reduce [PG&E Corporation's] earnings" based on a distribution of retained earnings.[108] We thus conclude that the ESOP tax deduction is appropriately treated as a shareholder asset.

10.1.2. Meals and Entertainment Deductions

DRA takes issue with PG&E's deductions and associated TY 2014 revenue requirement for travel, meals, and ticket expenses, and proposes that such items be excluded from the 2014 revenue requirements. DRA argues that these items represent social activities of dubious benefit to ratepayers. DRA points to previous Commission decisions which have rejected ratepayer funding for similar items such as Disneyland tickets, luncheons, and retiree dinners as an unfair economic burden on ratepayers.[109] Entertainment expenditures give the appearance of a "free lunch" at ratepayer expense. DRA claims that PG&E's expenses fall within the category of entertainment expenses the Commission has rejected in the past. DRA thus recommends that meals and entertainment expenses not be charged to ratepayers. DRA proposes that the associated income tax deductions be reduced by $179, 661 (50% of $359,321).

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[108] D.84-05-036 (15 CPUC2d, 42, 49).

[109] D.82-12-054 (10 CPUC2d at 140-141); D.93-12-043 (52 CPUC2d at 513-514); D.90-01-016 (35 CPUC2d 80, 135-136); D.12-11-051, mimeo, at 620-621.

PG&E argues that the costs of certain meal costs were already excluded from the GRC forecast and, for those that were not, the costs are associated with team-building activities and are consistent with sound business management. PG&E claims that the $359,321 in meals-related expenditures are properly within the revenue requirement and that the tax deduction related to these expenditures should stand at 50% of this amount.

Discussion

We adopt DRA's adjustment to exclude from the revenue requirement the expenditures and related tax-deductions for meals and entertainment. As noted by DRA, the Commission has consistently rejected rate recovery of entertainment, political, and social expenses of utilities because such expense are an unfair economic burden on ratepayers. Although PG&E defends the expenditures at issue as promoting "team building" and consistent with "sound business practices," PG&E does not refute DRA's allegation that these expenditures are similar to the sort that we have disallowed in previous proceedings.

10.1.3. Recognitions of Bonus Depreciation Rate Changes

DRA challenges PG&E's income tax assumptions concerning whether bonus depreciation legislation should be presumed for purposes of establishing 2014 revenue requirements. For its RO calculations, PG&E utilized a 50% rate for bonus depreciation for 2013 and a 12.5% rate for bonus depreciation for 2014. A 50% bonus depreciation provision became effective January 1, 2008 and was originally scheduled to expire after December 31, 2009. For 2010, the 50% bonus depreciation provision applied to a more restricted set of depreciable assets through September 8, 2010. For assets placed in service from September 9, 2010

through December 31, 2011, bonus depreciation was increased to 100%. The 50% bonus depreciation provision was extended for assets placed in service before January 1, 2014, and for certain property placed in service before January 1, 2015.

DRA recommends that a 50% rate for bonus depreciation be imputed into PG&E's deferred tax expense computation for 2013-2016, although the law extending bonus depreciation to 2014 has yet to be adopted. The law was changed to allow the 50% bonus depreciation rate for all of 2013, but based on the record in this proceeding, it remains uncertain if the 50% rate will be extended further. If the bonus depreciation rule is extended, DRA proposes that PG&E be directed to update its RO to reflect the bonus depreciation rate of 50% or whatever rate the government sets.

PG&E argues that no adjustment should be made to its revenue requirements for the effects of yet-to-be enacted changes regarding bonus depreciation. PG&E proposes that the Commission's previous treatment of bonus depreciation be continued, as reflected in the Tax Act Memorandum Account (TAMA) per Resolution L-411A.[110] PG&E argues that this approach ensures that ratepayers benefit in both the test year and post-test year period, either through additional capital investment enabled by the extension or by way of a future refund.

Discussion

We continue our treatment of bonus depreciation as reflected i n the TAMA per Resolution L-411A. Accordingly, no adjustment to the 2014 RO for possible changes in bonus depreciation rules is warranted. As PG&E notes,

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[110] CPUC Resolution L-411A; Advice Letters 3216-G-Q/3859-E-A.

Resolution L-411A, was the result of a process incorporating comments and revisions, designed to produce a reasonable ratemaking result. Through the protections provided by TAMA, all relevant effects of bonus depreciation will thereby be properly reflected in the ratemaking process in due course.

10.2. Depreciation Expense and Reserve

10.2.1. Overview

Depreciation expense allocates recovery of the capital costs of fixed assets, less salvage value, plus removal costs, extended over the estimated remaining asset service life. Depreciation expense is recognized for ratemaking purposes on a "straight line" basis over the estimated remaining average life of the asset in equal installments in accordance with Commission Standard Practice SP U-4.[111] This systematic recovery of asset costs over the useful life is important for intergenerational equity, because asset life may span several generations of ratepayers who benefit. As depreciation expense is recognized, the deprecation reserve is credited, thereby reducing rate base.

PG&E forecasts $2.27 billion in depreciation expense for 2014, comprised of $1.35 billion for ED, $464.0 million for GD, and $452 million for EG. PG&E also requests approval of its 2014 weighted average depreciation reserve forecast of $4,867.6 million for GD, $10,971.1 million for ED-related, and $8,246.3 million for EG.

PG&E's forecast 2014 depreciation expense is $820.4 million or 57%, higher than recorded depreciation expense in 2011, consisting of: ($181.5 million

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[111] Commission Standard Practice U-4 (SP U-4), "Determination of Straight Line Remaining Life Depreciation Accruals" was first issued in 1952, with the latest revision in 1961.

increase for GD, $531.8 million increase for ED, and $107.1 million for EG), PG&E attributes the increase mainly to plant growth and a change in depreciation accrual rates (due to net salvage estimates).

PG&E retained the firm of Gannet Fleming, to produce a Depreciation Study to develop the parameters (such as, ASL, curve type, and net salvage rates) to calculate test year 2014 depreciation expense. PG&E relied on historical plant records, plant maintenance practices, and expected future events that may affect estimates.

Parties resolved all disagreements regarding depreciation assumptions for generation asset accounts. Remaining disputes focus almost entirely on distribution mass asset accounts and center on: (a) salvage value/removal costs and (b) ASL of assets. The elements of depreciation expense, as forecasted by PG&E in comparison to DRA and TURN is set forth in Table 10-2 (at 10-16) of PG&E's Opening Brief. Parties' depreciation expense estimates for 2014 (based on year-end 2011 plant balances are summarized below:

$ in Millions

PG&E Proposal	DRA Proposal	TURN Proposal
$1,256.268	$983.556	$800.667

There are four ASL asset classes and 13 Net Salvage Value asset classes where DRA disputes PG&E's figures.

TURN recommends a reduction to PG&E's depreciation expense based on adjustments to many of its proposed net salvage levels. The stand-alone impact of TURN's salvage recommendations is a reduction of $324,208,952 million in annual depreciation expense based on plant as of December 31, 2011.

TURN calculates that approximately $500 million of increased depreciation expense forecast is due to PG&E's proposed changes to depreciation parameters.

For plant accounts on which TURN or DRA challenged PG&E's proposals, the utility-proposed parameters would cause an annual revenue requirement increase of $322 million. The primary driver of these amounts is the increase PG&E calculated for future costs of removing plant no longer in service. Where PG&E proposed changes to an account's ASL, it typically resulted in a longer remaining life that would serve to reduce depreciation expense, all else equal. Our adopted depreciation parameters, as discussed below, are set forth in Appendix C, Tables 12 and 13.

10.2.2. Uncontested Depreciation Parameters

We adopt PG&E's forecast assumptions relating to depreciation expense and related parameters (such as, negative salvage and remaining life rates) for generation assets for which no party raised objections. We apply the adopted parameters to the depreciable plant-in-service balances that we adopt as set forth in the RO Tables in Appendix C.

10.2.3. Removal Cost/Negative Net Salvage

The first area of dispute over depreciation forecasts involves removal/net salvage cost assumptions. PG&E forecasts separate percentage rates of removal costs net of salvage costs for each asset account. Because removal costs exceed salvage value for most asset accounts, the net salvage rate is negative in most instances. Comparison of forecasted negative salvage/removal cost percentages among PG&E, DRA, and TURN, is set forth in Table 10-3 of PG&E's Opening Brief. For 2014, PG&E proposes that customers fund $241 million in excess of currently authorized removal costs, when the benefit of pre-existing removal cost funding by earlier generations of customers is taken into account.

The PG&E depreciation study of net salvage, conducted by Gannett Fleming, generally utilizes a 20 year moving average of the ratio of (x) incurred

removal costs to (y) historical original cost of plant being removed. PG&E's net negative salvage estimates are based on this historical cost of removal and gross salvage data, plus judgment, incorporating impacts of age and inflation, and future levels of removal costs and gross salvage. For mass property in the electric transmission, electric distribution, and gas distribution asset classes, the study used net salvage data from 1990-2009.[112]

SP U-4 states that because removal costs are labor based, recent data is to receive greater weight. For example, the fraction used by the standard practice mostly reflects data accumulated in the most recent year. There is an implicit inflation element in SP U-4. Using 10-year rather than 20-year averages (as PG&E has done) would have effectively doubled the overall estimate (and negative net salvage rates).

PG&E claims its proposed accrual rates for removal costs understate the future cost of removal in nominal dollars, especially given inflation in construction and disposal activities in California. In D.07-03-044 (PG&E's 2007 GRC), the Commission stated that "the accrual method set forth in SP U-4 results in a conservative projection of future inflation that probably understates future removal costs in nominal dollars."[113]

PG&E claims that DRA's proposal only covers the current cost of removal and that TURN's proposal does not even do that.

PG&E claims its removal costs tripled from 1999 through 2011. Given that the funding of removal costs is for a weighted average remaining life of around

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[112] (Exh. 4 (PG&E-2), Chapter 11 at 18).

[113] D.07-03-044, at 232.

30 years, PG&E calculates that future removal costs might grow by a factor of 15 times (=3 x 3 x 1.7), if trends continue. PG&E does not request such costs from current customers, but argues that such data supports the validity of its removal funding request.

DRA does not offer a detailed technical critique of PG&E's net salvage rates, but argues that PG&E's forecasted amounts would contribute to a sudden and considerable retail rate impact. DRA believes that PG&E's depreciation study shows a disconcerting trend toward sharply escalating removal costs, a trend not reflected in GRC filings of other major Investor-Owned Utilities (IOUs). DRA thus recommends a cap of 25% to any increases in negative net salvage for this GRC to provide a more gradual level of increases so as to mitigate the rate shock that would result from adoption of the negative salvage rates requested by PG&E. DRA argues that deferring costs in this manner will not affect intergenerational equity. DRA also argues that a 25% cap will not impact PG&E's ability to fund removals, noting that current accruals exceed current removal costs. During 2003-2011, PG&E accrued more than twice the amount of removal costs spent in seven out of those nine years. TURN joins generally with DRA on this issue, in addition to offering other concerns.

PG&E opposes DRA's proposed 25% cap on negative net salvage increases, arguing that PG&E needs to catch up on past deferrals of past increases recommended in previous GRCs and adopting further deferrals will burden future ratepayers.

TURN's expert, Jacob Pous, claims that future removal costs forecasted by PG&E's consultant, Gannett Fleming, are too high and insufficiently substantiated. TURN recommends an overall reduction to PG&E's forecast of net salvage levels of $324,208,952 based on plant as of December 31, 2011.

PG&E proposed negative net salvage rates for nine of the 10 accounts in dispute. TURN's expert witness proposed different net salvage percentages for 10 of PG&E's mass property accounts, focusing on large accounts for which changed depreciation parameters would have the greatest impact. For half of the accounts where TURN disputed PG&E's figures, TURN concluded that a value at or near currently authorized net salvage percentages was reasonable. For two other accounts, TURN proposed a net salvage percentage less negative than currently authorized. For three of the accounts, TURN's proposed net salvage values are more negative than currently authorized, but not as negative as PG&E proposed.

PG&E claims that TURN's criticisms do not alter the overall steeply increasing removal cost trends and the empirical data. TURN believes that if costs of removal were going up in recent years, as PG&E contends, there would be a consistent upward trend when comparing 20-year-versus-10-year data. Instead, the vast majority of the increase is attributable to two accounts, $2.8 billion for Account 364 (Distribution Poles), and $12.3 billion for Account 365 (Overhead Conductor). The figures reported in Table 10-3 (of PG&E's Opening Brief) show removal cost increases of 67% or 180%, respectively, in these two plant accounts, with a wide range of percentage increases for forecasted removal costs between different accounts. TURN claims the increase for these two accounts dwarfs the change indicated for the other six accounts, which show far lower percentage increases and, in some instances, are flat or decreasing.

TURN argues that PG&E unduly relies on historical averages without adequate investigation of factors driving the averages. PG&E's recorded costs of removal were actually an allocation to removal of a portion of the overall costs of

plant replacement. TURN argues that this practice raises cause for concern regarding the actual allocation used for each account. TURN addressed how economies of scale can cause future costs of removal to vary from the amounts appearing in the historical database.

TURN claims that PG&E estimates the total replacement cost of a job and allocates a portion of that total to cost of removal. PG&E claims, however, that it estimates costs for each job directly by the work required (labor, materials, and overheads), and directly estimates removal costs related to the job based on the tasks required. PG&E then calculates the estimated costs (in dollars) as a percentage of the entire job cost. PG&E denies that this is an arbitrary allocation.

FERC Accounts 364 (Distribution Poles) and 376 (Gas Mains) are two of the largest accounts in terms of the plant in service. PG&E's direct testimony included a chapter devoted to pole replacement costs, and a discussion of the gas pipeline replacement program in the chapter devoted to gas distribution capital and investment planning. TURN claims that PG&E did not explain increased replacement costs that would have driven the increased costs of removal reported through 2009 in PG&E's depreciation study.

If the Commission accepts PG&E's assertions that depreciation rates should, on balance, only go up, TURN argues that existing average service lives could also be retained, rather than adopting PG&E's increases proposed for some plant accounts. TURN argues that such an outcome would result in PG&E collecting depreciation expense far greater than current removal costs, so the balance of pre-funded removal costs would continue to increase, but at a rate more consistent with the concern raised in the 2007 GRC.

TURN recommends retaining PG&E's existing - 15% net salvage parameter based on a review of historical data, and other facts that impact the appropriate

net salvage rate. TURN claims that the elimination of gross salvage value from 2001 through the present, after gross salvage had been recorded in every year prior to that, suggests a change in practice that PG&E has failed to substantiate or demonstrate to be reasonable. PG&E confirmed that it had recorded gross salvage associated with this account in the incorrect accounts. PG&E's proposed -40% is more negative than the figures reported for SDG&E and SCE, and more negative than Gannett Fleming reported for any utility in its database. PG&E failed to explain why its proposed net salvage parameter for this account is so much higher than the rest of the industry.

Discussion

We adopt Negative net salvage values by asset class based on the amounts set forth in Appendix C Tables 12 and 13. In doing so, we recognize the trend of increasing costs for negative salvage, but temper the magnitude of increase to mitigate impacts on current ratepayer.

For purposes of the 2014 test year, however, we generally do not adopt as much growth in negative salvage as PG&E requests. Setting a provision for negative salvage and ASL is not a precise science, and experts can differ in applying judgment in estimating these parameters. We present an account-by-account discussion of our adopted negative net salvage rates in Appendix E.

Although we generally find PG&E's estimates of negative salvage to be based on empirical analysis of cost trends, we are not convinced that all of the requested increases are defensible. PG&E cannot identify what percent of its

historical database is associated with a particular cause of retirement,[114] but does generally describe causes of increasing costs. PG&E identifies labor as the main cost to remove an asset. Labor costs depend on the time to do a job and labor rates, as well as overheads. Construction costs have increased for systemic reasons, including environmental and safety regulation. Safety measures may require more work. Environmental regulations may require additional steps to prevent spills or run-off of work site effluent. Local work requirements may require that work be limited to certain hours or that mitigation steps be taken to moderate disruptions.

Most of PG&E's negative net salvage estimates have been developed using 20 years of data and established trends. To the extent there are one time increases in costs that are reflected in data, PG&E's study took those anomalies into consideration.[115]

Although TURN claims that PG&E estimates the entire replacement cost of a job, then allocates a portion of this cost to cost of removal. PG&E showed that it estimates the job costs directly by the work required (labor, materials, and overheads). PG&E directly estimates the removal costs related to the job based on the tasks required, then calculates these estimated costs (in dollars) as a percentage of the entire job cost.[116] This is a reasonable allocation process.

We remain concerned with the growing cost burden associated with increasing cost trends for negative salvage. In PG&E's 2007 GRC, for example,

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[114] PG&E Data Response to TURN 63-45, as cited in Pous Testimony.

[115] Exh. 52 (PG&E-17), p. 2-45, Lines 17-31.

[116] Exh. 52 (PG&E-17), p. 2-35, Line 29 to p. 2-36, Line 22.

we expressed concern about PG&E's "large and growing balance of pre-funded removal costs" which, at that time, were at $2.1 billion.[117] That balance grew to $3.4 billion by the end of 2011, with additional growth of $606 million to $970 million for PG&E's forecasted accruals from 2012 through 2014.[118] Under PG&E's current proposal, the balance would increase by about $600 million per year. Over a 30-year remaining plant life, PG&E's current forecast assumptions imply an annual growth rate of 9.45%.

Given the magnitude of such increases, we are concerned that adopting PG&E's negative salvage rates in full would pose an unacceptably abrupt impact on current ratepayers. We thus adopt lower net negative salvage rates than PG&E requests for 2014 test year purposes based on the principle of gradualism. We appreciate that adopting reduced cost estimates for current test year purposes essentially increases the burden on future ratepayers to make up deferred costs over time. Our goal is therefore to balance the equities of current and future ratepayers.

The principle of gradualism applies where there is a recognized need to revise estimated parameters, but where the change is allowed to occur incrementally over time rather than all at once. Applying gradualism thus limits the approved increase that would otherwise be warranted, all else being equal, and mitigates the short-term impact of large changes in depreciation parameters. Also, it is advisable to be cautious in making large changes in estimates of service

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[117] D.07-03-044, at 228.

[118] PG&E Opening Brief at 10-31, Table 10-5, Note B.

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.

PG&E claims that it applies gradualism where it is proposing little or no change in a negative salvage rate compared to what it proposed in a prior GRC cycle. In evaluating whether a proposed increase reflects gradualism, however, we believe the more appropriate measure is how the change affects customers' retail rates. The fact that PG&E previously proposed higher removal costs than adopted has no bearing on how a proposed change would impact current ratepayers. Accordingly, we apply the principle of gradualism based on how a proposed change in estimate compares to adopted costs reflected in current rates, irrespective of what PG&E may have forecasted in an earlier depreciation study.

PG&E also argues that deferring recovery of removal cost increases to future GRC cycles unfairly causes future customers to pay much more. We recognize that future ratepayers should not be unfairly burdened with unduly large deferred costs from prior GRC cycles. Yet, the correct remedy is not to subject current ratepayers to similar unfair burdens by imposing inordinately large negative salvage cost burdens attributable to deferrals from earlier GRC cycles. Adopting PG&E's estimates would in fact burden current ratepayers with negative salvage cost deferrals that were not adopted for setting rates in prior GRCs.

Applying the principle of gradualism, however, also involves inter temporal equity trade-offs between current and future customers. These inter-temporal equity issues must be weighed in relation to overall cost increases imposed on customers in each GRC cycle. In view of the many new programs being implemented in this GRC, overall cost increases at issue in this GRC relative to past GRCs are substantial.

We are imposing new costs at a time when many customers have still not recovered from the severe economic recession that began in 2009. In past GRCs, we have exercised some degree of discretion when adopting increased removal cost estimates based on such concerns. For example, although we found SCE's removal cost estimates in its 2009 GRC reasonable, we declined to adopt those estimates because of economic difficulties facing ratepayers.[119] In PG&E's 2011 GRC, PG&E agreed to defer negative net salvage increases that PG&E otherwise deemed supportable. Imposing large negative net salvage cost increases raises similar concerns within the current economic environment which continues to be very difficult for many consumers.

We, of course, cannot foresee at this time what costs may be forecasted or adopted in PG&E's next GRC. Nonetheless, ratepayers in future GRC cycles will not pay for the same program cost increases approved in this GRC a second time, but will realize continued benefits from programs previously adopted. Depending on conditions prevailing in future GRC cycles, ratepayers may be better positioned to absorb removal cost increases in comparison to today's customers. In any event, we conclude some flexibility is warranted to moderate the impacts of removal cost increases that may otherwise found to be defensible, but without unfairly burdening customers in future GRC cycles.

In the interests of balancing potential cost impacts on both current and future customers, we conclude that a cap on removal cost increases is reasonable, and would not unduly shift deferred cost burden risk to customers in future GRC cycles. We also generally conclude, however that TURN's negative salvage

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[119] D.09-03-025 at 179-180.

estimates are too low, and could ultimately result in future customers absorbing an inordinate level of deferred removal costs attributable to current cost conditions. As a solution to balance customers' respective cost burden between current and subsequent GRC cycles, we shall thus limit the total level of estimated increases in net negative salvage costs in the following manner. For those asset accounts which net salvage amounts are contested by DRA and/or TURN, we generally adopt no more than 25% of the estimated net increase from current rates that we otherwise result from applying PG&E's net negative salvage rates. In this manner, we consider inter temporal equity effects on both current and future customers as a function of total cost increases anticipated over time. Current customers thus will bear a fair share of responsibility for removal costs while being spared the full impact of the cumulative growth in negative salvage including amounts attributable to prior GRC deferrals. At the same time, by increasing current rates to this extent, we mitigate the cost burden that future customers could otherwise face.

In comments on the Proposed Decision, PG&E does not dispute the validity of gradualism as a ratemaking principle, but objects that the gradual increase authorized here as being "just too gradual."[120] In making the objection, PG&E identifies no factual error, but rather expresses a difference in judgment as to the degree of gradualism that is warranted in this case.

We likewise are not persuaded by PG&E's calculations purporting to show adopted depreciation increases as funding $40 million below projected 2014 cost

[120] PG&E's Opening Comments to the Proposed Decision, page 21.

of removal expenditures.[121] To support this claim, PG&E subtracts an amount from the 2014 revenue requirement corresponding to the depreciation reserve component for removal costs. PG&E's subtraction exercise, however, doesn't refute the fact that the adopted revenue requirement for removal costs exceeds the projected $174 million cost of removal expenditures for 2014 by $291 million (=$465 -174 million). PG&E omits recognition of the offsetting effect of previously collected removal costs as reflected in the depreciation reserve. When this offsetting effect is recognized, no residual "rate benefit" remains, as claimed by PG&E, to reduce the current burden imposed on ratepayers to fund prospective removal costs. We thus disagree with PG&E's claims that our adopted depreciation provision doesn't cover 2014 projected removal expenditures.

We thus adopt net negative salvage rates as set forth on Appendix C, Table 12 to fund the estimated provision for removal costs. As a general approach, we adopt no more than 25% of PG&E's estimated increases in the accrual provision for removal costs. This limitation tempers the impacts on current ratepayers of the increase in the accrual rates for removal costs otherwise proposed by PG&E. In adopting this approach, we reach a resolution that gives some credence to the empirical methods used by PG&E while declining to pass along the full amount of PG&E's forecasted increase in negative salvage rates to current ratepayers. Particularly given the large overall magnitude of cost increases being absorbed by current ratepayers, we find it appropriate to moderate the further increased burden imposed in this GRC relating to growing

[121] PG&E's Opening Comments to the Proposed Decision, page 22.

negative salvage costs, while providing measured recognition in current rates of increasing cost trends.

10.2.4. ASL Estimates

As a basis for calculating depreciation expense and reserve balances, PG&E forecasts moderate extensions of ASL estimates for certain asset accounts utilizing the Simulated Plant Record Balance method (SPR).[122] DRA does not dispute PG&E's estimates of service lives or curves. TURN proposed different ASLs for 11 of PG&E's mass property accounts, focusing primarily on accounts with the greatest plant balance. Table 2-6 of PG&E's Rebuttal Testimony (Exh. PG&E-17) sets forth the differences in service life estimates among PG&E, DRA, and TURN. For the majority of the accounts in dispute, TURN's recommendation moves in the same direction as did PG&E's, yielding life-curves with longer ASLs than reflected in currently-authorized life curves. TURN's recommended life-curve, however, resulted in a greater increase to ASL than did PG&E's. For three accounts, PG&E proposed no change to currently authorized life-curve, whereas TURN proposed a different life-curve resulting in a longer ASL.

TURN recommends increases in average service lives exceeding those proposed by PG&E by as much as 7, 10, and even 15 years. TURN's ASL differences results in a depreciation expense reduction of $174,334,762 based on

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[122] This approach relies on simulated generic Iowa Survivor curves with a corresponding average service life. The simulation matches the best statistical interrelationship of additions, retirements and balances on an annual basis. The lowest sum of least squared differences between actual and simulated balances, based on an assumed curve and life combination, produces a range of results from which to estimate the future pattern of retirements for current investments.

plant as of December 31, 2011, as compared to the ASLs in PG&E's depreciation study.

TURN and PG&E both presented the informed judgment of experienced utility depreciation analysts. TURN claims, however, that its analyst gave a more complete explanation of his development of the recommended Iowa Survivor curve and associated ASL for each account in dispute. Witness Clarke (representing Gannett Fleming) argues, however, that selection of the curve is based more on judgment than statistical conformity.

PG&E argues, however, that TURN's ASL estimates are based on rigid mathematical interpretation of SPR results without accounting for weaknesses of the SPR model. PG&E claims that TURN's proposal is based on statistically insignificant differences in correlation of survivor curves and average service lives and reflects only one additional year of data compared to the 2011 GRC. PG&E also raises concerns that extending service lives as proposed by TURN will materially increase shareholder risk based on recent Commission precedent denying recovery of costs when plant is retired early and no longer used and useful.

Discussion

For asset accounts that are uncontested, we conclude that PG&E's ASL estimates are reasonable and adopt them for calculating 2014 depreciation expense. We also conclude that PG&E's ASL estimates for the 11 accounts in dispute are reasonable and adopt them. We do not find support for TURN's proposed increases in ASL. PG&E's recommended average service lives and

curve types are generally in line with those of other California utilities.[123] We address the adopted ASL parameters with respect to each disputed estimate on an account-by-account basis in Appendix E.2.

Expert judgment is involved in selecting the most appropriate life and curve combination as the basis for ASL estimates for each asset account. For the statistical methods employed for life analysis, the selection of a lower mode curve will generally result in a longer ASL and correspondingly lower annual depreciation expense. TURN's proposed ASL changes are based on selecting a different curve type compared to PG&E.

TURN's primary support for most of its ASL estimates is the statistical analyses of the historical data. TURN compared PG&E plant account balances to SPR simulated book balances based on an Iowa survivor curve and ASL. The SPR method employed for life analysis has limitations and statistical biases that often indicate longer service lives than are actually appropriate, as explained in academic literature.

TURN also considered the Conformance Index which is generally used to evaluate the goodness of fit between actual retirement data and calculated balances produced under each of the Iowa Survivor curves. The retirement experience index indicates the maturity of a particular plant account. The higher the index value, the higher-ranked the associated Iowa Survivor curve.

TURN's proposed ASL changes rely on one additional year of data compared to the 2011 GRC study and in many cases, and reflect only minor

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[123] *See* Tables (10-8 and 10-9) of PG&E's Opening Brief.

statistical differences compared to survivor curves used in PG&E's depreciation study.

Proposals regarding changes in curves and lives, from one study to the next, should be gradual.[124] Adopting the ASL estimates of PG&E conforms to the principle of gradualism, as previously discussed in connection with net salvage value estimates. Given these various considerations, we find PG&E's ASL estimates more defensible than those of TURN.

10.3. Other Operating Revenue

In calculating PG&E's 2014 revenue requirements, we account for PG&E's "Other Operating Revenue" (OOR), reflecting sources of revenues from transactions not directly associated with distribution, generation, or sale of electric energy or natural gas. These other revenue sources are estimated and subtracted from the revenue requirement collected from customers.

PG&E's 2014 forecast of electric and gas distribution OOR is $74.5 million and $25.2 million, respectively, and its EG OOR forecast is $14.4 million. PG&E derived its forecast on an item-by- item basis, first establishing base estimates from 2011 recorded revenues. PG&E then adjusted base year estimates to reflect changes that affect the forecast.

10.3.1. Reimbursed Revenues

DRA initially recommended an overall increase of $44 million in OOR based primarily on increased 2012 reimbursed revenues (i.e., revenues received from third parties to compensate PG&E for expenses subject to reimbursement).

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[124] Exh. 52 (PG&E-17), at 2-114 to 2-116.

DRA later filed errata to exclude from reimbursed revenues those amounts that were not GRC related which reduced DRA's disputed difference to $9.665 million. Of the remainder, $8.7 million constitutes differences in forecasts of reimbursed revenues and $1.0 million relates to DRA's reliance exclusively on 2012 recorded data.

Discussion

We accept PG&E's forecast and do not adopt DRA's proposed adjustment for reimbursed revenues. As explained by PG&E, reimbursed revenues and expenses are a zero sum game. Only recorded amounts in the GRC-recoverable accounts are considered in determining revenue requirements recoverable from customers. We thus find no basis to adjust the OOR estimate for reimbursed revenues, as proposed by DRA.

10.3.2. Timber Sales

PG&E included an estimate of $662,500 for timber sales in 2014.[125] TURN disputes PG&E's timber sales forecast, arguing for PG&E failed to establish the reasonableness of its estimate, particularly when the five-year average was 33% higher. TURN's forecast uses a five-year average, a common forecasting method where there are substantial variations on a year-to-year basis due to reasons beyond the utility's control, such as the impact of weather on timber sales revenue. According to PG&E, revenues recorded from timber sales fluctuate based on weather as well as the amount of forest fires. TURN argues that this type of forecast is best suited to reliance on a five-year average, consistent with prior Commission decisions

[125] Ex. 4 (PG&E -2, Results of Operations), at 17-5.

PG&E objects to TURN's forecast based in part on a characterization of TURN's position as proposing a forecast for the rate case cycle as a whole. TURN explains that its forecast is for the 2014 test year, rather than for the rate case cycle as a whole. PG&E argues that the dry winter of 2012-13 would only further support its estimate that the 2014 timber harvest will be sparse.[126]

Discussion

We adopt TURN's recommendation to increase PG&E's 2014 forecast for Account 456 for timber sales revenues by $887,000 based on a five-year average of timber revenues. The five-year average is a common forecasting tool when annual variations due to reasons beyond utility control impacts timber sales revenue. Although PG&E exerts some degree of control over timber sales, it is also subject to uncontrollable factors such as weather and forest fires. Given the potential variability and lack of control over factors affecting timber sales, we conclude that use of a five-year average is a reasonable basis for setting a test year forecast for OOR.

10.3.3. Water Sales

In its opening brief, TURN requests an increase in PG&E's forecasted water sales to $3 million (from $328,000) to reflect a developing arrangement with the Placer County Water Agency (PCWA) that is to bring about $4 million in revenues in 2014. TURN claims extenuating circumstances should allow the adjustment, even if the information regarding the new agreement was not available at the time PG&E put together its direct testimony.

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[126] Exh. 52 (PG&E-17) at 6-6, lines 6-13.

TURN recommends an increase of $2.672 million to PG&E's forecast for water sales to reflect additional revenues PG&E will receive from the PCWA. Under this new agreement, PG&E's revenues are expected to increase from about $200,000 per year to $3 million in 2014 and $4 million in 2015.

PG&E objects to reliance on estimated revenues from the new agreement since that information was not available at the time PG&E prepared its GRC filing.

PG&E argues that if items such as this are to be allowed to reopen the GRC forecasts, then other items that go the other way should be admitted as well. PG&E argues that the better course is to maintain designated periods in which forecasts must begin and end.

PG&E claims that there are many, at least equal and opposite post-NOI developments where expenses will be incurred that PG&E was unable to forecast. In the absence of a showing that PG&E's OOR forecast was unreasonable when made – and there has been none – PG&E' argues that its OOR forecast should stand.

Discussion

We adopt TURN's adjustment to OOR in the amount of $2.672 million for the estimated effects of additional revenues PG&E will receive from the PCWA under a new agreement increasing revenues. PG&E's opposition to TURN's adjustment is based on an incorrect premise. PG&E presumes that adopted results should not consider evidence subsequent to the applicant's initial showing unless the initial estimate is deemed unreasonable when originally made. We conclude that adopted results should be based on the entire record in the proceeding, not simply on what PG&E reasonably knew at the time its initial NOI estimate was made. Although TURN did not address this issue its own

prepared testimony, TURN did enter into evidence a cross exhibit indicating that PG&E recently negotiated the PCWA agreement under which annual revenues PG&E receives would increase.[127] The Joint Comparison Exhibit, also admitted into the record in this proceeding, shows TURN's recommendation on this issue as amounting to $2.672million. Accordingly, we increase PG&E's OOR estimate by $2.672 million for the effects of the PCWA agreement.

10.4. Escalation Rates

Since many 2014 TY expenses are derived from 2011 recorded costs, we apply escalation rates to account for price-level inflation between 2011 and 2014. PG&E calculates escalation rates from the IHS Global Insight's Utility Cost Information Service. We separately address escalation rates for the 2015-2016 attrition mechanism in Section 12 below.

PG&E's proposes a labor escalation rate of 2.79% based on a weighted – average of wage and salary increases of three employee groups: (1) unionized bargaining units; (2) clerical; and (3) management/administrative and technical. The weighted-average is based on the proportions that each of the employee groups represents of the total 2011 labor force. For unionized employees, PG&E proposes to use its most recent collective bargaining agreement for the 2012-2014 period.

DRA proposes an escalation rate of 2.61% based on a weighted-average of PG&E's union-represented labor escalation rates.

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[127] Tr. Vol. 24, 2983:16 to 2986:22, PG&E/Koenig; Exh. 226, at 2-3.

PG&E also presented proposed calculations of its non-labor and capital cost escalation factors, as updated in the Update Testimony, submitted on October 13, 2013. (Ex. 375.) No party opposes PG&E's non-labor escalation rates.

Discussion

We adopt PG&E's proposed labor escalation rate of 2.79%. We find this weighted average rate reasonable as it reflects PG&E's most recent collective bargaining agreement for the 2012-2014 period. We do not automatically presume that wages and increases included in a collective bargaining agreement with represented workers are ipso facto reasonable for purposes of rate recovery or labor escalation. In this instance, however, DRA presented no argument to show that PG&E's escalation rate based on bargained for wage increases is unreasonable, or that PG&E's methodology was flawed. Therefore, we adopt PG&E's updated labor escalation rates for 2014 as reasonable. We decline to adopt DRA's proposed rate of 2.61% which is only limited to union-represented wage escalation rates.

No party disputes PG&E's proposed non-labor escalation rate factors, as reflected in its Update Exhibit, and we adopt them for purposes of 2014 test year forecasts.

11. Rate Base, Working Cash and Finance Issues

PG&E is allowed to earn a rate of return on rate base components which are developed on a weighted average basis. Rate base represents the depreciated asset value of PG&E's net investments used to provide service to its customers. Rate base consists of utility plant in service, working capital, and Tax Reform Act deferrals, reduced by credits for: customer advances, deferred taxes and depreciation reserve. Our RO Model incorporates the adopted forecasts for capital additions and depreciation amounts, as addressed in prior sections of this

decision, in deriving the adopted rate base. PG&E forecasts working capital as the sum of the working cash forecast in Exhibit (PG&E-2), and the materials and supplies forecast in Exhibit (PG&E-7), Supply Chain – Materials Logistics and Planning. In this section, we resolve miscellaneous outstanding disputes which relate to the 2014 test year rate base.

11.1. Allowance for Funds Used During Construction

PG&E and DRA disagree regarding the methodology to calculate the AFUDC. PG&E applies AFUDC to account for the costs of financing construction work in progress (CWIP) projects lasting beyond 30 days. Once a CWIP project becomes operative, i.e., used and useful, capitalized AFUDC is part of the CWIP project cost added to plant in service. PG&E is then allowed to recover the capitalized AFUDC through depreciation charges over the useful life of the asset, and to earn a rate of return on the undepreciated portion of AFUDC.

PG&E calculates its AFUDC rate in accordance with the FERC formula. As noted in the Federal Power Commission (predecessor to the FERC) Order 561, the objective of the AFUDC formula is to:

> …give recognition to the interrelationship between capital utilized for rate case purposes and the capital components of AFUDC in a manner that would permit a utility to achieve a rate of return on its total utility operations, including its construction program, at approximately the rate which would be allowed in a rate case.[128]

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[128] Fed. Power Comm'n Order 561, 57 F.P.C. 608 (Feb. 2, 1977), at 608.

PG&E includes long-term capital, but no short-term debt, in its AFUDC rate, and currently applies an AFUDC rate of 8.79% which is equal to its 2011 authorized cost of capital.

DRA proposes a revised methodology to derive PG&E's AFUDC rate for ratemaking purposes by applying short-term debt for 30% of CWIP financing. DRA calculates no revenue requirements adjustments to reflect its AFUDC proposal for this GRC,[129] but the effect of any revised AFUDC rate would presumably be reflected in PG&E's 2017 GRC revenue requirement. DRA proposes that short-term debt rate for AFUDC purposes be set equal to PG&E's actual average short-term debt rate. Based on its forecast rate for 3-month commercial paper of 0.16%, DRA recommends an AFUDC rate limited to 3.91%.

DRA argues that imputing 30% short-term debt in the AFUDC rate will provide a regulatory restraint on costs. DRA claims that PG&E's exclusion of short-term debt has the effect of maximizing the AFUDC rate, and that the existing AFDUC treatment provides no incentive for PG&E to control costs. DRA claims its AFUDC methodology will reduce customer costs and provide a better incentive for cost efficiencies.

DRA calculates that use short-term debt to fund 30% of CWIP would have amounted to $0.531 billion based on CWIP balances at December 31, 2011, and $0.629 billion based on September 30, 2012 CWIP. Adding these amounts would have resulted in short-term debt of $2.178 billion at December 31, 2011, and $1.028 billion at September 30, 2012. Adding short-term debt equal to 30% of CWIP at September 30, 2012 ($0.629 billion) to the average short-term

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[129] Tr. Vol. 26 at 3394:9-27, DRA/Wuehler.

borrowings for 2008 to 2012 ($0.775 billion), gives a total average short term debt of $1.404 billion. DRA claims these numbers are well below PG&E's current revolving line of credit of $3 billion.[130]

DRA also proposes that the remaining 70% of the AFUDC rate include only embedded long-term debt, and exclude common equity. DRA claims its proposal to exclude equity from AFUDC follows the approach adopted in D.11-05-018 where the allowed return on a non-productive asset was limited to the cost of long-term debt. DRA argues that it is inappropriate to reward shareholders with a full return for projects that are not used and useful and which provide no benefit to ratepayers. DRA argues that CWIP fits the category of a project that is not used and useful and thus not entitled to earn a full rate of return.

PG&E opposes DRA's AFUDC proposal, arguing that a requirement to finance 30% of CWIP with short-term debt would exhaust almost all of its liquidity, leaving it vulnerable to sudden short-term capital needs, market shocks, and other disruptions. PG&E argues that due to its other short-term borrowing demands, there is not sufficient short-term debt to finance 30% of CWIP. PG&E requires short term credit for general working capital to fund seasonal cash requirements, balancing account under-collections, natural gas working inventory, and as a buffer for unexpected short-term cash requirements. Short-term debit also serves as funding of collateral for energy procurement.

PG&E claims that increasing its use of revolving short-term debt to fund CWIP would raise costs by reducing liquidity and increasing risk.[131] PG&E also

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[130] Ex. 88 (DRA-20).

claims that financial rating agencies and investors would regard use of short term borrowings for revolving debt as additional permanent leverage, requiring offsetting equity and/or higher returns.

PG&E also argues that DRA ignores FERC requirements for AFUDC. PG&E claims that FERC provides for an allocation of short-term debt where the utility has short-term debt outstanding that can be allocated to CWIP. PG&E argues that DRA's proposal departs from cost-of-service ratemaking and guarantees under-recovery of PG&E's actual, reasonable costs of financing CWIP.

Discussion

We accept PG&E's existing AFUDC methodology as reasonable, which is based on the approved FERC formula. We find no valid basis to deviate from the FERC formula or to require a new AFUDC methodology based on DRA's arguments.

We conclude that PG&E has followed FERC guidance in computing AFUDC. FERC rules provide for some allocation of short-term debt to CWIP under certain circumstances, but permits PG&E to offset short-term debt against the following items: balancing accounts, fuel oil inventory, natural gas inventories, and nuclear fuel. PG&E uses short-term debt for other purposes as well. FERC does not require PG&E to identify the other uses in order to exhaust short-term uses merely by tracking specified items.[132] For the portion of CWIP financed by equity, FERC rules provide for use of the adopted rate of return.

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[131] Exh. 64 (PG&E-25) at 5-4, line 1 to at 5-5, line 4.

[132] Exh. 64 (PG&E-25) at A-1 to A-9.

DRA claims that by capitalizing AFUDC based on the long-term cost of capital, PG&E's AFUDC treatment is virtually the same as including CWIP in rate base from the inception of construction. Ratepayers, however, do not pay a return on capitalized AFDUC until the project becomes operational and is added to rate base. PG&E incurs financing costs from the inception of the project, however, and must access long-term capital markets from the inception of construction of a project just as it does after a project becomes operational. Capitalizing AFUDC reasonably compensates PG&E for such financing costs.

We are also not persuaded by DRA's claim that allowing PG&E to apply the AFUDC rate based on its long-term cost of capital offers little incentive to control costs or minimize the time to complete projects. Capitalized AFUDC is a valid construction overhead just as much as is capitalized labor or administrative costs. We find no basis to believe that simply by capitalizing valid overhead costs, PG&E's incentives to control costs or are impaired. DRA has not shown that PG&E has misused its short-term borrowing capacity, or allocated short-term borrowings imprudently in reference to capitalized AFUDC.

We also find no valid basis to exclude the equity component from the AFUDC rate. DRA relies on D.11-05-018 to propose a disallowance of the equity component of AFUDC. We conclude, however, that the disallowance adopted in D.11-05-018 has no bearing on the AFUDC rate to finance CWIP. The issue addressed in D.11-05-018 involved non-productive investments with no prospective value to ratepayers. DRA presumes that CWIP is similarly a non-productive asset that provides no benefits to ratepayers.[133] To the contrary,

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[133] Exh. 88 (DRA-20) at 18, lines 7-13.

CWIP does provide value to ratepayers, although that value is realized as a function of the time to complete the CWIP project. Accordingly, the treatment of a non-productive asset in D.11-05-018 provides no basis to disallow the cost of equity capital that is otherwise deemed necessary in financing CWIP. DRA establishes no valid basis to conclude that common equity is not a valid component included in the AFUDC rate.

Adopting DRA's proposal to impute short-term debt into AFUDC rates would create a difference between the CPUC and FERC accounting methods regarding AFUDC accruals added to CWIP. PG&E would have to keep a separate set of accounting records, as PG&E must maintain its books in accordance with the FERC uniform system of accounts. The difference in recorded plant (gross plant) would produce an ongoing difference in depreciation and rate base that would last indefinitely for all of PG&E's constructed assets. Keeping two sets of books would increase administrative costs.

In declining to adopt DRA's AFUDC proposal, we also avoid any risk of adversely affecting PG&E's existing short-term borrowing capacity, or increasing borrowing costs. PG&E's revolving line of credit with a capacity of $3 billion is already less than its optimal short-term credit capacity of $4 billion.[134] Given all of these considerations, we accept PG&E's AFUDC rate, and decline to adopt DRA's AFUDC modification proposal.

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[134] Exh. 42 (PG&E-10) at 11-13, lines 24-29.

11.2. Inclusion of Nuclear Fuel Costs in Rate Base

PG&E's nuclear fuel inventory is currently excluded from rate base. Nuclear fuel carrying costs are recovered through the ERRA proceeding and compensated at the short-term commercial paper interest rate. For purposes of 2014 GRC revenue requirements, however, PG&E proposes to change the current treatment and include nuclear fuel inventory in rate base in the amount of $399.3 million. Based on this proposed change, PG&E would earn a full rate of return, including long-term debt and equity, on nuclear fuel inventory, instead of recovering only short-term commercial paper interest currently set a 0.4% annual rate.

DRA and EPUC propose that Diablo Canyon nuclear fuel inventory be excluded from rate base, and continue to be addressed in the ERRA with financing cost recovery at the short-term interest rate. DRA and EPUC rely on various Commission decisions addressing nuclear fuel financing for Southern California Edison Company (SCE), citing decisions from 1985-2009.[135]

DRA and EPUC argue that the Commission has repeatedly affirmed a policy of excluding SCE's nuclear fuel from rate base dating back to 1986. SCE currently finances nuclear fuel entirely with long-term debt and receives a waiver from its equity maintenance condition to do so. In both the SCE and Sempra GRCs, the Commission rejected demands that the utilities finance CWIP with short-term debt agreeing with them that doing so would increase rollover risk.

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[135] *See* D.85-12-107 as modified in D.86-05-095; D.87-12-066; D.88-09-031; D.93-01-027; D.96-01-011; D.06-05-016; and D.09-03-025.

DRA and EPUC contend that continuing the current ratemaking treatment of nuclear fuel protects ratepayers from an unwarranted, significant rate increase that would result from PG&E's proposal. DRA argues that financing nuclear fuel with short-term debt is lower cost to ratepayers. PG&E responds, however that the Commission in recent GRCs has recognized the drawbacks involved in using short-term debt to finance assets on a long-term basis, and that where an asset is financed with 100% debt, the equity financing of the remaining assets must increase to maintain total leverage and credit quality.

PG&E argues that the cited cases applicable to SCE and do not address whether PG&E has--or can obtain--sufficient short-term debt to cover nuclear fuel financing. PG&E estimates it needs up to $4 billion of short-term debt to fund existing short-term requirements, but can only obtain $3.0 billion in the market today. PG&E claims it does not have sufficient short-term debt capacity to finance nuclear fuel balances of nearly $400 million and growing, or of CWIP.

PG&E's year-end 2012 CWIP balance was $1.9 billion. PG&E claims it would need of third of its existing $3 billion of bank credit facilities to finance CWIP and nuclear fuel, thus leaving inadequate short-term debt capacity for working capital with a cushion for unforeseen emergencies.

PG&E argues that the cited cases involving SCE's nuclear fuel treatment occurred at a time when short-term debt was available to SCE to finance its nuclear fuel balancing account. The Commission reexamined this precedent in D.06-05-016 and chose to continue it based on a finding that "[n]othing has changed." PG&E claims, however, that key material changes have occurred related to PG&E's need for and access to short-term debt that affect the financing of nuclear fuel.

PG&E argues that a ruling by the Commission that nuclear fuel does not belong in rate base will not, in practice, result in actually financing nuclear fuel with short-term debt, but instead will simply cause PG&E to under-recover its reasonable, actual financing costs.

EPUC contends that the changed circumstances claimed by PG&E all occurred before the last cost of capital decision adopted by the Commission in December 2012.[136]

PG&E argues that nuclear fuel is a long-term asset requiring long-term permanent financing, unlike balancing accounts that are expected to have zero balances over an annual cycle, it will need nuclear fuel as long as it operates DCPP. PG&E argues that nuclear fuel inventory has the characteristics of a long-term asset. PG&E thus claims that it requires a permanent capital commitment for nuclear fuel as a long-term asset.

EPUC's position is that PG&E is free to finance nuclear fuel inventory as it sees fit, but that Commission precedent and policy dictate recovery of carrying charges for nuclear fuel inventory through ERRA at the short term debt rate. EPUC draws a distinction between approved ratemaking treatment and PG&E's discretion in financing nuclear fuel. EPUC argues that the Commission has explicitly made this distinction between ratemaking and actual financing sources, stating that "the Commission's chosen method of calculating the carryings costs does not dictate any particular financing approach."[137]

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[136] D.12-12-034.

[137] D.87-12-066, 26 CPUC2d at 433 (emphasis added).

Discussion

We shall continue the currently authorized ratemaking treatment for nuclear fuel inventory for purposes of 2014 revenue requirement adopted in this GRC. The existing treatment of nuclear fuel inventory carry costs through the ERRA proceeding shall continue with compensation based on short-term interest rates. Accordingly, we adjust PG&E's 2014 rate base forecast to exclude nuclear fuel inventory in the amount of $399.3 million.

We are not persuaded that changing the ratemaking treatment for nuclear fuel inventory, as proposed by PG&E, is warranted at this time. Adopting PG&E's proposed change in nuclear fuel cost recovery would change the status quo, significantly increasing ratepayer costs with no corresponding improvement in service quality. Conversely, declining to adopt PG&E's proposal at this time merely continues the status quo with respect to nuclear fuel inventory carrying cost recovery. Also, since we are not adopting DRA's proposals regarding AFUDC, as discussed above, PG&E should not experience changed demands on short-term borrowings merely as a result of our continuing with the existing treatment. For similar reasons, denial of PG&E's nuclear fuel inventory proposal should not require any immediate rebalancing of PG&E's capital structure.

PG&E also points to the financial crisis of 2008-2009 and its current credit rating of BBB, targeted for possible downgrade, as recently changed conditions. PG&E argues that in light of these conditions, eliminating incentives to use short-term financing rather than less risky sources of capital is warranted. PG&E

claims it does not have sufficient short-term debt capability to finance long-term assets.[138]

When PG&E's most recent authorized rate of return was set in D.12-12-034, however, such factors already existed. Although PG&E's recovery for nuclear fuel inventory carrying charge was limited to the short term debt rate, PG&E's adopted cost of capital and capital structure were deemed sufficient to maintain an acceptable credit rating.[139]

If PG&E's actual use of short term debt were to increase, we recognize that equity financing of the remaining assets might need to be correspondingly adjusted to keep leverage, and credit quality, the same. PG&E is required by the so-called equity maintenance condition to maintain its average equity ratio at no less than that authorized in PG&E's cost of capital proceedings, currently 52%. To the extent that rebalancing of common equity may have been warranted to accommodate more short-term debt, however, such rebalancing presumably would have been at issue when the current nuclear fuel treatment was first adopted. In its 2003 GRC, PG&E for the first time included nuclear fuel in rate base without objection.[140] In connection with overall settlements of its 2007 and 2011 GRCs, however, PG&E agreed to remove nuclear fuel from rate base and seek cost recovery through the ERRA. Thus, by continuing with a ratemaking practice in effect since 2007, we create no new demands on short-term borrowing

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[138] Exh. 42 (PG&E-10) at 11-13, lines 20-33.

[139] 24 TR 2964-5 (EPUC/Ross).

[140] Until PG&E's 2003 GRC, rate recovery for the Diablo Canyon power plant was not governed by traditional cost of service ratemaking.

capacity. Merely continuing the existing ratemaking treatment should thus not cause an adverse change in PG&E's credit status or borrowing capacity, particularly in the near term.

While maintaining the status quo for purposes of nuclear fuel ratemaking for this proceeding, however, we acknowledge that PG&E has raised valid concerns regarding the long-term viability of limiting recovery of nuclear fuel carrying costs to a short-term interest rate. As a general financing practice, long term assets should be financed with long-term sources of capital. There is evidence to support the claim that nuclear fuel exhibits characteristics of a long-term asset. For example, nuclear fuel is recorded in FERC plant accounts.[141] Other kinds of fuel inventory, by contrast, are recorded as current assets. Nuclear fuel more closely resembles a piece of equipment than does conventional oil or gas inventory.[142] Nuclear fuel lasts three to five years in the reactor and takes one to two years to manufacture. Unlike other fuels, nuclear fuel is not fully consumed, but remains intact (albeit irradiated) after use.

As PG&E notes, however, GRC treatment relating to carrying costs of assets such as nuclear fuel cannot be easily divorced from issues relating to cost of capital.[143] The Commission considers capitalization ratios and costs of capital for each utility after holding hearings based on detailed presentations, including evidence relating to the impact of leverage on credit ratings. Yet, because PG&E's cost of capital is reviewed and its authorized rate of return is set in a

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[141] Tr. Vol. 24, 2967:2-4, EPUC/Ross.

[142] Exh. 262 at 11.

[143] Exh. PG&E-10 (General Report) at 11-4.

separate proceeding, it is beyond the scope of this GRC to comprehensively address all cost of capital issues as a result of parties' divergent proposals for nuclear fuel cost recovery.

We thus believe that it would be premature to adopt a change in the current ratemaking treatment of nuclear fuel at least until all relevant implications for PG&E's adopted cost of capital can be fully considered. In seeking an immediate change in ratemaking treatment in this GRC, PG&E focuses on how the current treatment affects investor returns earned on nuclear investment, but omits discussion of the significant increase customers would bear if its proposal were adopted. The annual revenue requirement for nuclear fuel inventory currently is $1.6 million. PG&E's proposed rate base treatment of nuclear fuel inventory would result in an annual revenue requirement of $47 million, a 2,856% increase.[144] We must also consider these significant ratepayer impacts before determining whether to approve such a change in ratemaking treatment as PG&E proposes.

Accordingly, we defer a further resolution of proposals to adopt rate base treatment of nuclear fuel inventory until PG&E's next cost of capital proceeding. Based on a full record relating to the range of effects on financial risks, costs of credit and liquidity as well as ratepayer impacts, we will consider in that proceeding whether it is appropriate to include nuclear fuel in rate base prospectively, and if so, what ratemaking processes or adjustments are warranted to implement such a change.

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[144] Ex. 299 (PG&E Data Response 001-009); *see also* Ex. 150 (EPUC/Ross), at 2.

11.3. Customer Deposits

PG&E and TURN disagree concerning the rate base treatment for customer deposits. PG&E holds customer deposits as a result of requiring new customers to establish credit under Tariff Rule 6. A customer who does not qualify for credit must submit a deposit pursuant to Tariff Rule 7. PG&E refunds the deposits within 12 months to those customers that have generally paid their bills on time. PG&E pays interest on the deposits equal to the three-month commercial paper rate.

TURN proposes that customer deposits be applied as a rate base offset equal to PG&E's customer deposits on a 2012 weighted average basis without escalation, which equals $156.575 million, of which $137 million is GRC-related.[145] Treating customer deposits as TURN proposes would reduce PG&E's GRC revenue requirement forecast by nearly $20 million.

TURN argues that the consistently large level of deposits serves as a source of working capital not provided by investors. TURN believes that treating customer deposit obligations as rate base is consistent with the treatment of other working cash items that also are reductions to rate base, even though they are liabilities. TURN also proposes that the Commission either expense the interest that PG&E will pay in the refunding of customer deposits at a rate of 1%, or authorize PG&E to recover actual deposit interest in a balancing account. TURN argues that the latter approach is likely to be more accurate, as not all customer deposits will be returned with interest pursuant to PG&E's tariffs. TURN

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[145] Ex. 116 (TURN, Marcus Testimony) at 80, 84.

forecasts deposit interest of about 1% ($1.566 million) to reflect the continuing relatively low interest rates.

TURN claims that customer deposits are a permanent source of working capital provided by customers rather than by shareholders. TURN claims that PG&E has consistently held more than $100 million in customer deposits over the past decade in amounts ranging between $140 million to $200 million since 2007.[146]

PG&E opposes TURN's proposed treatment of customer deposits. PG&E argues that in order to be consistent with its proposed treatment of nuclear fuel and CWIP, customer deposits should be included in PG&E's capital structure as a source of debt. PG&E argues that the impact of this debt should be considered as part of its capital structure in relation to equity. If no matching equity is deemed necessary in the cost of capital proceeding, then PG&E believes the overall rate of return could be adjusted downward to achieve the same revenue requirement effect as by a rate base reduction. If full matching equity is required, however, the revenue requirement would be limited to reducing PG&E's embedded cost of debt (providing a weighted downward adjustment of 0.4%).

PG&E argues that that customer deposits, as well as nuclear fuel and AFUDC, are all of a permanent nature. PG&E argues that it is inconsistent and inappropriate to apply different ratemaking treatment for essentially the same permanent items. If the Commission finds that both CWIP and nuclear fuel

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[146] *Id.* at 82, Figure 3 (PG&E Customer Deposits 1996-2012).

represent permanent (not short-term) commitments of capital, PG&E would agree that customer deposits similarly represent a long-term cash source.

PG&E recommends, as an interim step, treating customer deposits as low cost debt (with an appropriate reduction to the cost of long-term debt in this GRC), so that the impact of this source of capital on financial structure can be fully considered, rather than being simply subsumed within a working cash computation. (*See* Table 11.1 of PG&E's Opening Brief.) PG&E believes this approach best achieves the underlying purpose of Commission Standard Practice U-16 (SP U-16), which removed interest bearing customer deposits from consideration in the working cash computation, but which does not preclude considering this item as part of the capital structure.

Assuming consistent ratemaking treatment of long-term uses and sources of cash, the remaining issue would be whether deposits should be treated as a reduction to working cash or as long-term debt outside of PG&E's capital structure. If the Commission relies on past precedent on nuclear fuel involving SCE, PG&E requests the Commission consider a conventional analysis of customer deposits based on past precedent. On this basis, PG&E thus argues there should be no rate adjustment for customer deposits.

TURN's witness conceded these customer deposits are security deposits, not ordinary "true-ups" of cash and accruals of expenses and revenues, which dominate the working cash computations. Conversely, if PG&E were required to post very low, interest bearing deposits with a bank, TURN's witness was unsure whether he would agree that those similarly secure "uses" of cash could be added to rate base. The nature of interest bearing deposits distinguishes them from other working cash issues.

PG&E argues that as a policy matter, excessive uses of short-term debt are unwise; and that the permanent sources and uses of cash should be treated consistently. Consequently, if the Commission chooses to rely on precedent on nuclear fuel involving SCE, then PG&E requests the Commission consider a conventional analysis of the customer deposit issue, based on past precedent.

Discussion

We decline to apply customer deposits as a rate base offset as proposed by TURN. PG&E has a legal obligation to refund customer deposits recorded as an interest bearing liability on the balance sheet, the same as other debt obligations. Customer deposits are not equity. These facts do not support treating customer deposits as a form of equity to apply in reducing rate base, as TURN proposes. We find that TURN's proposed treatment of customer deposits deviates from Commission SP U-16 which excludes interest bearing customer deposits from working cash, and only includes non-interest-bearing customer deposits. As the Commission has previously held, SP U-16 is only a guide, and deviations may be appropriate where circumstances so warrant. [147] As a general matter, however, we presume that ratemaking treatment consistent with SP U-16 should be deemed reasonable, especially where there are no special circumstances that justify a deviation.

Our treatment of Customer Deposits has varied over time and among utilities, depending on the circumstances. TURN argues that any reasons for any difference in treatment of customer deposits adopted for PG&E compared to SCE

[147] *See*, e.g., D.04-07-022 at 253-254; and D.09-03-025 at 289, as cited in TURN's Comments to the Proposed Decision, at 19.

should be explained. We have not always adopted identical treatment of customer deposits among utilities or for the same utility over time. The treatment of customer deposits adopted for PG&E here is based on the circumstances before us which leave discretion to tailor the adopted ratemaking treatment accordingly.

In PG&E's 2007 GRC, (D. 07-03-044), TURN raised a similar complaint that the adopted treatment of customer deposits for PG&E was inconsistent with that of SCE. In that proceeding, we declined to treat customer deposits as a reduction to working cash, but found that PG&E and the Settlement Agreement calculated working cash in accordance with SP U-16. We viewed the Settlement outcome on working cash as presumptively reasonable.

In certain prior decisions, for example, we determined the rate of interest applied for balancing accounts should be the same as the rate on customer deposits, based on short-term rates.[148]

As we directed with respect to nuclear fuel, we direct that a comprehensive review of the treatment of customer deposits should be made in the next cost of capital proceeding. In the meantime, as a middle ground, we shall treat customer deposits as a source of long term debt. We recognize that PG&E's support for treating customer deposits as a source of long term debt as an interim step only on the condition that PG&E's proposal to include nuclear fuel in rate base. We also recognize that PG&E does not advocate ratemaking treatment of customer deposits as a source of long term debt in conjunction with excluding nuclear fuel from rate base. Nonetheless, we disagree with PG&E's

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[148] D.91269 (OII 56), 3 CPUC2d, 204, at 1; D.92496 (OII 56), 4 CPUC 2d, 693, 8, *11.

claim that the treatment of nuclear fuel must be inextricably linked to PG&E's proposed treatment of customer deposits. Despite PG&E's claims to the contrary, we find it reasonable to treat customer deposits as a source of long term debt as an interim step, while also in the interim excluding nuclear fuel from rate base. We believe that this adopted treatment reasonably mitigates the more extreme impacts that would result from adopting either PG&E's or TURN's position on customer deposits, while providing a reasonable interim proxy for revenue requirement purposes.

For purposes of this proceeding, therefore, customer deposits shall be reflected in the capital structure as a form of low-cost debt. We shall use PG&E's calculation of the adjustment to interest costs based on this treatment, resulting in an interest rate difference of 5.5% - 0.4% applied to customer deposits of $137 million, as reflected in Table 11-1 of its opening brief, with a resulting $7 million reduction in the GRC revenue requirement. In the next cost of capital proceeding, the impact on PG&E's cost capital and capital structure as a result of customer deposits as a source of capital can be fully considered and reflected in rates.

As noted by PG&E, if no matching equity is deemed necessary in the cost of capital proceeding, the overall rate of return would be reduced so that there would be the same revenue requirement effect as if it reduced rate base. If full matching equity is deemed to be required, however, the revenue requirement effect would be limited to reducing PG&E's embedded cost of debt (by providing for a weighted downward adjustment of 0.4%).

PG&E also notes that it routinely runs large balancing account undercollections where it earns only the short-term interest rate. We agree that it is more appropriate to treat customer deposits as financing these

undercollections first, financed at short term interest rates, rather than applying these deposits against rate base earning the full rate of return. The Commission previously found that balancing accounts and customer deposits should both earn the short term debt rate.[149]

11.4. Miscellaneous Working Cash Issues

Working cash is one of the subsets included in rate base to compensate shareholders for payment of day-to-day operating expenses in advance of receipt of offsetting revenues from customers. Working cash is generally calculated by adding and subtracting certain specified items; and by the timing of inflows and outflows of cash as calculated by a lead-lag study. The working cash determination is guided by SP U-16, dated September 13, 1968. A positive amount of working cash represents a permanent utility investment and is included in rate base. Negative working cash represents funds provided by ratepayers and reduces rate base.

Table 11-2 from PG&E's Opening Brief summarizes the differences between PG&E and DRA/TURN relating to working cash issues. We resolve relevant disputes relating to working cash below.

11.4.1. Lag Days for Income Tax Payments and Revenue Collection

PG&E and DRA disagree regarding the forecast of lag days for Revenue, Federal Income Tax (FIT), and California Corporate Franchise Tax (CCFT). DRA uses data from the 2011 GRC. For other working cash and lag day forecasts, DRA uses either recorded 2012 data, a four-year average, or a six-year average.

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[149] D.91269 (OII 56), 3 CPUC2d 197, 204; D.92496 (OII 56), 4 CPUC2d 693, 705.

For FIT expense lag days, DRA recommends 110.85 days, based on PG&E's figure in the 2011 GRC. Given that no FIT recorded tax data is available for 2008, 2009, and 2010 to make an updated calculation, DRA argues that the most recently adopted figure from PG&E's last GRC is a reasonable basis for this GRC, rather than using PG&E's forecast of lag for 2014 (based on forecasts of taxable income for 2014). DRA thus increased the lag from 69.24 days to 74.52 days, after reflecting transition bonus relief in 2014 to110.85 days.

DRA recommends 132.85 days as expense lag days for CCFT, which is the average based on PG&E calculated average lag days for 2008 through 2011. DRA does not use PG&E's 2014 GRC specific State Income Tax (SIT) Lag calculation as well as data provided for 2012. DRA's proposal reflects a change from 52.96 days to 132.85 days resulting in a rate base reduction of $25.6 million in 2014.

PG&E claims DRA uses inconsistent approaches that are all biased towards the steepest reduction in working cash. Since the 2003 GRC, PG&E has forecasted working cash items using base year data or a four-year average of recorded data unless special circumstances exist.

DRA asserts that base year data does not reflect reduced revenue lag due to SmartMeter™ implementation. DRA believes that SmartMeter implemention should make the bill collection system more efficient relative to the last GRC, so that the revenue collection lag day forecast for 2014 should be shorter instead of longer. Therefore, DRA recommends that the average revenue lag day be 40.81 days which is the same one PG&E proposed in the 2011 GRC.

PG&E responds that billing lag does not depend just on when a bill is issued, but also when it is paid, as well as on disbursements and refunds. The Commission initiated changes to liberalize deposit policies after the financial crisis of 2008-2009, which may be one factor in extending lag in receipt of

revenues. Another could be the growth of disbursements and refunds due to demand side management or other changes. SmartMeter™ was well into implementation in 2011. To the extent it was not, PG&E made a reduction to working cash for implementation in 2012 and following years,[150] recorded revenue lag for 2012 was actually longer than in 2011.[151]

Discussion

We adopt PG&E's forecast of lag days for Revenues, Federal Income Tax, and CCFT. We find no valid basis to reject PG&E's use of base year revenue lag data to forecast the test year revenue lag which has been accepted in the last four GRCs.[152] We decline to adopt DRA's calculation of lag days based on data from the last GRC. PG&E has consistently forecasted working cash items using base year data or a four-year average of recorded data unless special circumstances exist.

For CCFT expense payment lag days, we find no basis to rely on the recorded total Company four-year average of 2008-2011, as proposed by DRA. Even assuming a four-year average was an appropriate basis, DRA's calculation omitted overpayments from the prior year that are applied to the first quarter estimate of the next year.[153]

PG&E's long-standing practice is to forecast tax lags using income taxes forecasted in the RO. We find PG&E's approach reasonable here. As test year

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150 Exh. 89 (DRA-21) at 18, lines 3-9.

151 Exh. 52 (PG&E-17) at 5-16, line 31 to at 5-17, line 2.

152 Exh. 52 (PG&E-17) at 5-18, lines 3-7.

153 Exh. 52 (PG&E-17) at 5-13, line 6 to at 5-14, line 9.

forecasted taxable income goes up (as it does for 2014 due to increasing rate base), the SIT lag is reduced.

For Federal Income Tax expense lag days, we likewise find no valid basis to rely on forecasted lag from the last GRC (based on taxable income forecasts for 2011). We adopt PG&E's forecast of FIT lag based on taxable income forecasts for 2014 since it offers a more accurate result for purposes of working cash.

11.4.2. Goods and Service Lag Days

For goods and services, TURN recommends 27.06 days and PG&E forecasts a lag of 25.99 days. PG&E's final proposal yields a $12.09 million reduction in 2014 rate base relative to its original goods and services lag estimate.

DRA proposes to increase in the goods and services lag from 20.56 days to 39.64 days resulting in a rate base disallowance of $29.1 million in 2014. DRA claims PG&E cut the previous lag days in half by incorporating new study methods and a new base year (2011) and that PG&E refuses to perform a study on the 2012 recorded year to verify its results. DRA recommends use of the goods and services lag forecast from the last GRC that was developed from study conducted for 2008 (the base year in the last GRC).

PG&E disagrees with DRA's approach, arguing that 2011 data is more recent, relevant, robust and accurate. PG&E denies that the 2011 study was biased or poorly conducted or that a new study, using more recent data, would increase the forecast of lag days. The 2011 study spanned a greater time period and contained a sample size almost five times larger than the 2008 study. This data also captures current trends of electronic payments to suppliers that has enabled earlier payments and enhanced competition among potential bidders.

TURN recommended an additional 6.5 days for Goods and Services lag, yielding a disallowance of $14.5 million in 2014 for rate base associated with data

issues involving the Goods and Services Lag Study. Due to resource constraints, TURN based its calculation on a limited review of PG&E's model, focused on entries above $200,000, amounting to a sample of 60% of the total.

PG&E does not agree with TURN's focus on just the invoices over $200,000 for adjustment, arguing that the study is biased if only the invoices over $200,000 are adjusted. PG&E did not conduct an extensive study of TURN's excluded vendor invoices, but as an alternative, PG&E proposes to use TURN's excluded vendor list to adjust the entire population of 43,000 invoices, not just those invoices greater than $200,000. Thus, under PG&E's approach, all invoices are excluded from those 48 vendors, regardless of the dollar amount of the invoice. PG&E performed this adjustment and calculated a raw goods and services lag of 26.65 days. After the subtraction of transit time of 0.66 days, the net lag is 25.99 days, which is 1.07 days less then TURN's proposal. The resulting rate base reduction is $12.09 million.

TURN states that it is willing to accept PG&E's revised calculation of a raw goods and services lag of 26.65 days, or a net lag of 25.99 days when adjusted for transit time of 0.66 days. TURN cautions, however, that PG&E's figure is likely conservative. TURN did not audit invoices for less than $200,000 to determine whether PG&E included invoices that are not properly considered as goods and services. TURN reviewed of approximately 1,150 items, leaving nearly 42,000 un-reviewed. TURN believes the possibility still exists that other vendors in the sample should be removed.

Discussion

We adopt the revised lag day figure of 26.65 lag days for goods and services, producing a net lag of 25.99 days, adjusted for transit time of 0.66 days. This adjustment is based on PG&E's response to TURN's recommendation, as

described above. Incorporating this adjustment, PG&E's original rate base forecast relating to goods and services lag days is reduced by $12.09 million. This outcome produces a reasonable estimate of goods and services lag by covering the entire population of invoices, not just those over $200,000.

We decline to adopt DRA's forecast for goods and services lag which relies on the last GRC forecast that was developed from a now-stale study conducted for 2008 (the base year in the last GRC). DRA produced no evidence that the 2011 study was biased or poorly conducted or that a new study, using even more recent data, would result in an increase forecast in lag days. PG&E explained that these studies involve significant effort and take at least several months to perform.

11.4.3. Deferred Debits

Deferred Debits represent miscellaneous cost items that are in the process of amortization and are not included in other current asset accounts.[154] PG&E forecasts deferred debits of $1.588 million as a rate base component based on a 12-month weighted 2011 recorded average adjusted with inflation escalation factors.

DRA disputes PG&E's forecast of deferred debits, and recommends a reduction of $1.073 million. DRA relies on a six-year average of deferred debits (2007-2012), rather than 2011 recorded base year data. DRA claims that the monthly recorded deferred debits from 2007-2012 shows no obvious trend.

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[154] Deferred Debits are booked to FERC Account 186, and defined by FERC (18 CFR Part 101) as including "all debits not elsewhere provided for, such as miscellaneous work in progress, and unusual or extraordinary expenses, not included in other accounts, which are in process of amortization and items the proper final disposition of which is uncertain."

Discussion

We adopt PG&E's forecast of $1.588 million for deferred debits, based on the 12-month weighted 2011 recorded average adjusted with A&G inflation escalation factors. We find this forecast reasonable. As noted by PG&E, the deferred debit balance has turned positive since 2010 due to charges every month related to implementation of the Habitat Conservation Plan. DRA's six-year average with inclusion of data prior to 2010 fails to account for this ongoing addition to deferred debits, which is expected to continue through the GRC period. Inclusion of 2012 data is not reasonable without adjustment for first-time customer payments that PG&E does not expect to recur.

11.4.4. Accrued Vacation

Accrued vacation represents money accrued through operating expenses for future liabilities which PG&E has available until it pays employees for vacation. For purposes of rate base, accrued vacation is applied as a deduction from operational cash as defined by the Commission SP U-16. PG&E relies on 2011 data to forecast $45.7 million for under accruals relating to the vacation leave deduction.

DRA proposes to disallow $19.9 million in rate base for 2014 associated with a change to PG&E's vacation accrual calculation that uses 2012 recorded monthly average data and removes an accounting adjustment of $45.7 million. DRA also fixed (hard-coded) the 2012 accrued vacation amount to be the 2014 forecast for accrued vacation. PG&E's standard methodology, however, dynamically adjusts for test year labor forecast changes

DRA thus recommends using 2012 recorded monthly average accrued vacation data with no accounting adjustments allocated as follows:

$93.539 million for Electric Distribution, $50.228 million for Gas Distribution, and $52.790 million for EG.

PG&E was subject to a one-time accounting adjustment that increased the vacation accrual but was never reflected in operating expenses and was not recovered from customers. Shareholders absorbed those changes. PG&E argues that it would be unfair to pay a return to customers on an accrual that customers never funded.

PG&E argues that if its labor expense forecasts are adopted, DRA's approach would understate the accrued vacation reduction to rate base. Regardless of the outcome, PG&E claims that the DRA methodology is inconsistent with longstanding practice. In particular, PG&E points to OII 86 (adopting the 1986 tax act), where the Commission faced a number of changes in tax accounting that resulted in significant acceleration of tax liabilities. These included unbilled revenues and bad debts. Under a strict "flow through" method of accounting, PG&E would have been entitled to collect substantial sums from customers when the IRS required taxpayers to switch from the reserve method of reflecting bad debts to the direct charge-off method. The Commission, however, recognized accounting methods used for ratemaking (and followed in computing taxes) to prevent collection of these items from customers when they never received the benefit. PG&E argues that a similar principle applies here to vacation accruals.

Discussion

We adopt PG&E's rate base forecast of $45.7 million for under accruals relating to the vacation leave deduction. PG&E uses base year data to develop a "vacation accrual factor" (*i.e.,* accrued vacation pay divided by labor expense) to be applied to the RO model, based on labor expense.

PG&E's approach produces a reasonable result. We agree that because shareholders absorbed the increased costs from accounting changes relating to vacation accruals, it would be unfair to require shareholders to pay a return to customers on an accrual that customers never funded.[155] Adopting this result is consistent with our previous decisions finding that when customers have not pre-funded the vacation pay reserve, they should not be credited for the pre-funding and should not receive credit for accruals they did not fund.[156]

11.4.5. Prepaid Expenses

PG&E forecasts $76.784 million in company-wide prepayments for Electric Distribution, Gas Distribution, and EG in 2014. Company-wide Prepayments include prepaid software license fees and prepaid insurance. DRA's forecast is $63.893 million in prepayments. Parties' differences are due to the different A&G expense estimates. DRA projects slower growth of A&G accounts 924 and 925, and recommends certain adjustments to PG&E's anticipated growth in these two A&G accounts. As the result of these adjustments, the test year insurance growth factor is lowered to 1.424 instead of PG&E's recommendation of 2.063. Incorporating this growth factor into the prepayment calculation yields total prepayments of $63.893 million for Electric Distribution, Gas Distribution, and EG, a reduction of $12.9 million.

PG&E ties its growth factor directly to its forecast of growth of the insurance cost from 2011 to 2014.[157] PG&E disputes the DRA forecast, but agrees

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155 Exh. 52 (PG&E-17) at 5-10, line 19 to 5-11, line 2.

156 *See* D.88-12-082; 30 CPUC 2d 156, 181.

157 Exhibit (PG&E-9), Chapter 3, Table 3-4, line 14).

to re-calculate the insurance growth factor using the adopted insurance amount for the final working cash calculation.

Departmental Prepayments include a recovery charge for the cost of the second refueling outage for Diablo Canyon. Prepaid expenses arise from the fact that the payment for the nuclear refueling is being made in 2014, but is being recovered over the entire three year rate cycle (2014-2016).

PG&E proposes $14.865 million in departmental prepayments in 2014, while DRA's forecast is $8.565 million. There are several components of PG&E's departmental prepayments—one associated with the second refueling outage for the DCPP, another one for different DCPP functions, plus a credit adjustment of $9.443 million for Long Term Service Agreement for Gateway and Colusa generation plants.

PG&E expects to pay $56.1 million in 2014 for the second refueling outage at DCPP, and requests cost recovery spread over three years. The yearly recovered amount would be $18.7 million. PG&E proposed recovery of $18.7 million as an O&M expense in 2014 in the nuclear O&M testimony.

PG&E claims the correct pre-payment amount to be recovered over the three year cycle is one-third of $56.1 million total. DRA, however, argues that the $18.7 million O&M expense charge should be subtracted from the $56.1 million total before calculating the prepayment amount to be recovered over the three-year rate case cycle. DRA thus calculates the prepayment amount as $12.4 million (equal to one-third of $37.4 million) instead of $18.7 million (one third of $56.1 million). The difference is $6.3 million of rate base.

Discussion

We adopt PG&E's forecast for company-wide prepayments for software license fees and prepaid insurance. We conclude that since PG&E's calculation is

tied to the growth in insurance cost from 2011 to 2014, the resulting forecast is reasonable.

We also adopt PG&E's prepayment forecast for the second DCPP refueling outage. Based on PG&E's numerical example developed during cross-examination of the DRA witness, we are persuaded that a payment of $3 would result in annual payments of one-third of $3, not one-third of two-thirds of $3, as asserted by DRA. Applying PG&E's example, a payment of $56.1 million correspondingly yields an average out-of-pocket payment of one third of that total each year. In rebuttal, PG&E further showed that DRA's method does not correctly calculate the pre-payment over the three-year GRC cycle as it fails to recognize the pre-paid balance remaining in 2015 equal to $18.7 million.

11.4.6. Adjustments to Other Receivables

TURN proposes an adjustment to working cash of $15.183 million, representing 50% of PG&E's Non-Energy Billing System (NEBS) receivables outstanding for one year or longer in 2011. TURN proposes that 50% of these receivables accounts be excluded from working cash, claiming that such accounts should be deemed non-recoverable.

PG&E argues that customers should pay either the increased bad debt expense, by reason of the accounting change (amortized over three years), or a return on the outstanding balance if there is no accounting change, but should not escape 50% of the costs altogether. TURN, however, provides no adjustment to expense for this bad debt accounting change.

PG&E argues that provided costs are fairly reflected (either in working cash or through an increased bad debt factor), attempting to forecast such a percentage of aged debts would only add accounting complexity for no useful

purpose, since customers would pay either way. PG&E believes that the better course is to leave accounting practices as is, and to continue to compensate PG&E for payment lags rather through an increase in uncollectibles.

PG&E opposes TURN's proposal to write-off 50% of bad debts over one year, arguing that the proposal is arbitrary. These accounts are still in the process of collection, with one exception.[158] PG&E argues that TURN's proposed acceleration for ratemaking of bad debt deductions would result in an omission of legitimate expenses, unless the one-time increases in expense are recognized in the year of accounting change for GRC recovery. PG&E would be agreeable to no longer financing the deferred expenses, if TURN wishes for PG&E to accelerate them, but PG&E opposes disallowance as the result of a onetime accounting change.

Discussion

We decline to adopt TURN's proposal to reduce working cash by excluding 50% of PG&E's NEBS receivables outstanding for one year or longer in 2011. We find insufficient support to conclude that 50% of these debts should be treated as unrecoverable. As PG&E notes, writing off the accounts earlier would produce a marginally higher uncollectible expense, which would presumably carry over to future forecasts of expenses. Ratepayers ultimately pay either through higher uncollectible expense or through a higher rate base. The items remain in the account as a receivable until declared uncollectible. During that time, PG&E is out the cash and therefore it has to be financed.

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[158] Exh. 52 (PG&E-17) at 5-18, line 8 to 5-19, line 11. The one exception is $5 million related to departing load.

PG&E expresses a willingness to meet with TURN to address transparency concerns in the next GRC in a way that does not adversely affect customers or the utility.

11.5. Fuel Oil Inventory Carrying Costs

PG&E maintains an inventory of fuel oil for use at its Humboldt Bay Power Plant, and seeks to recover carrying costs to finance this fuel oil inventory by including $1.533 million in its 2014 test year rate base. DRA disputes this proposed ratemaking treatment. DRA proposes instead that fuel oil inventory be excluded from rate base, and that carrying costs associated with fuel oil inventory continue to be addressed in the Electric Revenue Recovery Adjustment (ERRA) proceeding which limits fuel oil inventory carrying costs to the cost of short-term debt. DRA argues that this proposed treatment is consistent with a long history of Commission precedent, and that PG&E has offered no valid basis to change it.

Discussion

We adopt DRA's recommendation to continue to limit fuel oil inventory carrying cost compensation to the short-term interest rate as currently prescribed in the ERRA proceeding. DRA's recommendation is consistent with our past ratemaking treatment of this cost as noted in multiple citations to Commission decisions in DRA's testimony.[159] We affirm our prior treatment recognizing that because fuel oil "is a commodity that can be used as collateral for financing and is distinguishable from fixed plant and land…fuel should not be afforded rate

base treatment, regardless of its characteristics."[160] PG&E's compensation for fuel oil inventory in the form of short-term interest is adequate. PG&E has provided no basis to change in the existing ratemaking treatment for fuel oil inventory. We find no basis to deviate from our long-standing treatment of fuel oil inventory through the ERRA proceeding. We accordingly adopt DRA's recommendation to reduce PG&E's rate base forecast by $1.533 million to exclude fuel oil inventory costs for the Humboldt Bay Power Plant.

11.6. Financial Health

PG&E sponsored testimony in support of its claims regarding the importance of setting revenue requirements that afford a reasonable opportunity to earn its authorized return while providing safe and reliable service.[161] PG&E also provided examples of ratemaking treatment that it believes would impair such opportunity, including certain other parties' proposals on nuclear fuel, AFUDC, attrition, employee incentive plans, and service lives for depreciation purposes.

TURN asks that the Commission not endorse PG&E's efforts to earn its authorized return, which TURN characterizes as "financial cheerleading." TURN also raised issues regarding the current financial health of PG&E that PG&E had not explicitly raised in its opening testimony.

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[159] *See* Exh. DRA-21, pp.5-9, citing for example, D.85-12-017, 20 CPUC2d 111, 112, as modified in D.86-05-095; D.87-12-066, 26 CPUC2d at 392; D.88-05-031, 29 CPUC2d at 314; D.06-05-016 at 271; D.09-03-025 at 361.

[160] D.87-12-066.

[161] Ex. 1 (PG&E-1) at 5-15, Lines 2-3.

TURN concludes that PG&E operates in a supportive state regulatory environment, as backed by the Commission's emphasis on credit ratings during PG&E's bankruptcy, and by recent financial community reports and writings.

TURN performed a comprehensive review of PG&E's financial health, both historically and going forward.[162] TURN noted that: (1) PG&E has returned to investment grade credit ratings since it emerged from bankruptcy in 2004; (2) the financial community recognizes that PG&E's financial prospects are good, with earnings forecasts for the 2014 test year being consistently good. The dividend history for PG&E Corporation is strong. Wall Street analysts recognize that there will be financial consequences of the 2010 San Bruno gas pipeline explosion, and PG&E's earning projections include estimates of those consequences.

TURN argues that PG&E is financially healthy, and concludes that although the San Bruno explosion has affected PG&E's financial picture, the financial community expects that those risks will be resolved in 2013 and 2014 without long-term harm to the company. TURN argues that PG&E has shown no good cause for the Commission to approve PG&E's requested GRC revenues in order to improve PG&E's financial condition, and that granting all of PG&E's test year and attrition requests is not necessary to maintain financial health required to provide adequate utility service.

Discussion

We recognize that the parties disagree concerning how to characterize the role and importance of PG&E's financial health as a factor in deciding revenue

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[162] Ex. 134 (TURN, Weil Testimony) at 5-6.

requirements issues in this GRC. For purposes of setting test year and attrition year revenue requirements in this proceeding, we find it sufficient to acknowledge the importance of the GRC process as 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. In other parts of this decision, we separately address the disposition of the various substantive issues listed by PG&E above as having potential adverse impacts on its financial health. We conclude, however, that the revenue requirements that we adopt and the disposition of disputed ratemaking issues are 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.

12. Attrition Adjustment Mechanism

12.1. Overview

PG&E seeks approval of a post-test year attrition rate adjustment (ARA) mechanism to adjust authorized levels of utility revenues to mitigate attrition-related costs during 2015 and 2016. PG&E claims it will face revenue requirement shortfalls that cannot be solved even with radical reductions to capital spending unless its ARA proposal is approved. PG&E proposes separate treatment of expense and capital growth, which would yield additional revenue increases of $492 million (6.1%) in 2015 and $504 million (5.9%) in 2016. PG&E's forecasted attrition increases are primarily attributable to capital investments which affect rate base and depreciation, irrespective of inflation.

PG&E claims its proposed ARA is simple and does not reflect all drivers of post-test-year cost growth including those associated with serving new customers, replacing aging infrastructure, and complying with increased

government regulations. PG&E argues that because it is not seeking full recovery of all drivers of increased costs, productivity savings are embedded in its proposal and further test year adjustments would constitute double counting.

PG&E proposes that separate percentage factors be applied to test year expense amounts to reflect price inflation for labor, medical costs, and goods and services, as described in Exhibit (PG&E-11). PG&E also proposes separate balancing account treatment for gas leak repair costs where the implementation of a new leak survey technology is expected to significantly increase the volume of leak repairs in 2015 and 2016 in comparison to the test year.

PG&E proposes a separate allowance for additional capital expenditures in the attrition years based on 2014 Test Year plant additions, adjusted for accrued depreciation, and the estimated change in deferred tax liabilities. PG&E's calculation assumes that post-test year capital additions remain constant in real terms, even though PG&E forecasts higher capital spending. PG&E applies an escalation percentage to 2014 test year capital levels, but does not seek additional costs for serving new customers and repairing and replacing an aging infrastructure.[163]

PG&E also proposes an ARA allowance for upward or downward adjustments for certain exogenous changes, referred to as a "Z-factor," based on similar criteria as previously applied to other utilities. PG&E proposes a one-time $10 million deductible per event (positive or negative depending on the

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[163] PG&E's proposed capital addition escalation rates for 2015 and 2016 are set forth on Table 3-4 of Exh. (PG&E-10), and are based on IHS Global Insights Q1 2011 Power Planner Forecast.

adjustment) with an exception for a few specific exogenous changes that are a normal part of doing business and have no disproportionate impact on PG&E.

DRA presents a different ARA proposal that would produce an increase of $168.4 million (2.6%). TURN also presents its own ARA proposal that would produce a 2015 revenue requirement increase of $240.5 million (3.6%). We note the principal features of the DRA and TURN proposals for attrition below.

12.2. DRA's ARA Proposal

DRA recommends that attrition increases be limited to $168 million (2.6%) in 2015 and $158 million (2.4%) in 2016, and argues that PG&E's ARA proposal would yield excessive increases. DRA's primary recommendation is to set ARA increases for 2015 and 2016 slightly higher than the CPI, yielding increases of 2.3% per year for 2015 and 2016, plus additional revenues for forecasted natural gas leak repair expenses, as separately addressed in Section 3 of this decision. DRA's recommends escalation factors based on the All-Urban CPI (or CPI-U) (from the 4th Quarter Global Insight Cost Planner), equal to 1.7% for 2015 and 1.9% for 2016. Under this proposal, PG&E would receive additional revenues for forecasted gas leak repair expenses, resulting in total ARA revenue increases of $168.4 million (2.6%) in 2015 and $158.7 million (2.4%) in 2016.

PG&E claims its capital revenue requirement growth will be significantly greater than CPI-based escalation, and argues that DRA's proposed CPI-based mechanism would not adequately fund the utility's needs.

DRA also offers an alternative ARA proposal, in the event that a two-part ARA mechanism is adopted similar to PG&E's proposal. DRA's alternative recommendation incorporates separate expense and capital adjustments but modifies PG&E's proposed escalation rates. Under this alternative, DRA proposes: (1) wage escalation based on the CPI; (2) medical plan costs escalation

using an IHS Global Insight forecast; and (3) additional leak repair costs. DRA does not dispute PG&E's post-test year capital additions methodology, but differs in the treatment of the 50% bonus depreciation provision. DRA assumes that the 50% bonus deprecation provision is extended through 2014-2016 whereas PG&E assumes that the 50% provision ends after 2013.

DRA does not oppose a Z factor mechanism, but does oppose PG&E's specified exceptions. PG&E conceded to DRA's position that the Z-factor should not apply to the test year.

12.3. TURN's Proposed ARA

TURN's proposes a two-part ARA to separately adjust expenses and capital expenditures, to produce a 2015 attrition revenue requirement increase of $240.5 million (3.6%). TURN proposes use of the consumer price index-urban area (CPI-U) to escalate test year expenses, allowing some inflation protection but without cost-plus indexing of expenses. TURN's recommended development of attrition expenses as a two-part attrition mechanism is parallel to the expense portion of DRA's primary recommendation, which develops the attrition revenue requirement by escalating test year revenue requirement by the CPI-U.

TURN recommends that capital additions revenue requirements be escalated using an average of historical capital additions. TURN developed a seven-year average of plant additions in 2012 dollars based on data for 2005-2011. (*See*, Attachments B-D of Yap Testimony). TURN escalated the average at projected CPI-U to 2015 and 2016 attrition year levels using the IHS Global Insight Cost Planner forecast from fourth quarter 2012. (*See* Exhibit DRA-22, Appendix 1).

TURN argues that while test-year expenses should be forecasted as accurately as possible using specific information about PG&E's costs, the ARA should simply rely on one broad index instead of multiple utility specific indices. TURN believes that such an approach provides some implicit stretch factors to enhance management incentives to achieve cost savings. TURN argues that its proposed two-part attrition mechanism that combines CPI escalation of test year expense levels with a calculation of attrition capital revenue requirement based on a long-term average of recorded plant additions is consistent with prior Commission policy and provides an appropriate balance of interests.

TURN argues that the attrition approach that PG&E requests in this case has been granted in only three decisions, which is fewer than 10% of decisions during the past three decades. In contrast, TURN's approach has been adopted in more than half of the decisions (17) during that period. During the same period, three decisions did not grant any attrition, five addressed attrition through performance based ratemaking, and seven simply applied a percentage increase over test year amounts.

TURN argues that during the past three decades, to its knowledge, the Commission was never discouraging additional utility investment as PG&E claims. From1980-1993, when the Commission exclusively relied upon the two-part attrition mechanism that PG&E characterizes as an antiquated methodology, both PG&E's and SCE's plant grew substantially at rates that met or even exceeded current levels.

TURN argues that the Commission historically has not closely covered projected attrition revenue requirement through the attrition mechanism. Yet, utility rate base has grown during that period. TURN claims that PG&E's proposed expense attrition mechanism has become "a self-fulfilling prophecy"

where the more the utility spends, the more will be passed along in the future. TURN believes the expense escalation should be based on a broad measure of inflation to provide PG&E with incentives to productively manage operations.

TURN characterizes PG&E's proposal as simply trending projected net additions upward at industry escalation rates for an additional two years. TURN argues that there is room for considerable error in such a process.

PG&E claims that TURN's seven-year average would under-fund capital programs, as compared to PG&E estimates, by $1.10 billion in 2015 and $1.17 billion 2016. TURN's proposed funding level is also over $700 million less than PG&E's planned additions for 2013. TURN's proposal would also fund capital programs at a lower level than DRA's alternative by $240 million in 2015 and $145 million in 2016.

PG&E claims that any approach that fixes attrition year capital expenditure funding levels well below test year amounts constitutes illogical and inefficient management of capital programs. PG&E argues that TURN's proposed methodology relates to a period when the Commission was discouraging additional utility investment. PG&E believes that escalating test year additions by a small but fixed amount is more in line with reasonable expectations for future capital spending during 2015 and 2016. DRA does not dispute PG&E's capital additions escalation proposal as part of its alternative ARA recommendation.

TURN responds that the contrast between its proposal based on historic trends and PG&E's proposed spending levels demonstrates that PG&E's projections are extreme. TURN argues that the cumulative recorded and projected wage escalation for PG&E has greatly exceeded the cumulative utility

industry average wage escalation for the same period based on data from DRA's attrition showing.

TURN argues that limiting attrition expense increases to CPI enhances management incentives to develop savings. PG&E claims that customer growth already places pressure on the company to increase productivity. PG&E would have the attrition revenue requirement more closely cover the cost of service. TURN's seven-year average would under-fund PG&E's capital programs estimates by $1.10 billion in 2015 and $1.17 billion 2016. TURN's proposed funding level is also over $700 million less than PG&E's planned additions for 2013. TURN's proposed seven-year average would underfund capital programs in comparison to DRA's alternative by $240 million in 2015 and $145 million in 2016.

TURN argues that an escalation of expenses at CPI offers the appropriate balance between shareholder need for relief and ratepayers' need for moderation in growth in rates.

Discussion

For the attrition years 2015 and 2016, we adopt an ARA to mitigate the effects of attrition anticipated between test years. We adopt ARA forecast increases of 4.57% for 2015 and 5% for 2016, as set forth in Appendix D. In adopting an ARA allowance, we have duly considered the conflicting arguments both in support of and in opposition to the parties' proposals. We adopt an ARA that incorporates certain recommendations from each of the parties that sponsored ARA proposals, as discussed below.

In adopting an ARA for PG&E, we weigh the relative burdens on ratepayers of PG&E's proposal in relation to the risks that PG&E's ability to provide safe and reliable service would be impaired under the DRA or TURN

proposals. We apply judgment in finding the right balance between an overly simplified mechanism and one that is too complex or that may be unduly burden ratepayers. In any event, we seek to promote PG&E's incentive to stretch to achieve productivity between test years.

The ARA is not intended to replicate a test year analysis, or to cover all potential cost changes so as to guarantee PG&E's rate of return through 2015 and 2016. The ARA is merely to mitigate economic volatility between test years to a reasonable degree so that a well-managed utility can provide safe and reliable service while maintaining financial integrity.

We adopt a two-part mechanism to capture distinctions driving attrition increases (a) for expenses versus (b) for capital expenditures. We decline to adopt DRA's primary proposal to set post-test-year revenue increases simply based on a single index, with no distinction between expenses versus capital additions. While applying a single index, as proposed by DRA, offers simplicity, we conclude that such an approach fails to adequately capture the distinctions between expense and capital expenditure attrition. We also decline to apply the CPI as an escalation factor. The CPI reflects consumer retail price changes, not the escalation in wholesale purchases of utility goods and services. Accordingly, we generally adopt industry-specific escalation factors, rather than use of the CPI.

We also make provision for certain attrition-year cost changes through balancing account mechanisms as discussed in other sections of this decision. We also adopt a Z-factor mechanism to capture certain unforeseen exogenous events, as discussed below. The specific elements of our adopted ARA are discussed below. By adopting the balancing account treatment and Z-factor provisions for specified items, together with attrition allowances relating to

expense and capital growth, we conclude that the overall result promotes a fair balance of interests between ratepayers and shareholders.

12.3.1. Wage Escalation

We adopt an ARA allowance for wage escalation based on PG&E's proposed factor of 2.79% per year for 2015 and 2016 attrition for labor wages. PG&E's 2.79% rate is based on wage rate increases of 2.75% for union employees (operating units) and 2.97% for non-union employees (A&G), yielding a company-wide weighted average escalation of 2.79% per year for 2014-2016.

We decline to adopt DRA's attrition proposal for wage increases based on CPI increases of 1.7% and 1.9% for 2015 and 2016, respectively. DRA proposes that wage attrition be tied to a CPI of 1.7% for 2015 and 1.9% for 2016 as a proxy for estimated wage escalation. DRA argues that PG&E does not have negotiated wage rates in place for 2015 and 2016, but has an opportunity to control labor costs. DRA argues that PG&E's proposed ARA wage rate increase does not provide management with the incentive to negotiate lower labor escalation rates and to better control wages and salary levels.

We conclude that reliance on the CPI would not be in line with the above-referenced escalation rates most recently approved for SCE and Sempra, and would also be 1% below the average increases for PG&E management employees and contractual increases under PG&E's current collective bargaining agreements. We accept PG&E's labor escalation forecast as reasonable since it is based on wage levels currently provided to management and bargaining unit employees under existing collective bargaining agreements and which were developed based on benchmark data. PG&E's wage escalation factor of 2.79% is also reasonable in comparison to the escalation of 2.75% most recently approved in D.13-05-010 for Sempra covering 2015 increases. Also, PG&E's escalation rate

is in line with in the SCE GRC attrition mechanism adopted in D.12-11-051 which incorporated labor forecasts of 3% for 2013 and 2.65% for 2014.

12.3.2. Health Plan Escalation

We adopt DRA's recommended medical cost escalation based on IHS Global Insight's Group Health Insurance index resulting in increases of 6.4% for 2015 and 6.3% for 2016. DRA's proposed rates are based on forecasted group health insurance escalation rates in the IHS Global Insight Cost Planner for the fourth quarter of 2012. The rates are also in line with PG&E's forecasted medical escalation rates of 5.4% for 2012, 6.4% for 2013, and 5.4% for 2014.

We decline to adopt PG&E proposed higher health plan attrition escalation factors of 8.4% for 2015 and 8.2% for 2016 which are based on Towers Watson actuarial estimates. PG&E challenges DRA's reliance on IHS Global Insight data, arguing that it is based on national health care data that does not accurately predict PG&E's health care cost increases.

We acknowledge that the IHS Global Insight data is based on a mix of different companies reflecting nationwide data. We recognize that PG&E's company-specific health plan costs may exceed national averages. Nonetheless, some uncertainty remains as to whether the actual post-test year increases must climb as high as the 8.4% predicted by PG&E. In the interests of promoting the incentive for PG&E to contain health plan cost increases through the attrition period, we find it reasonable to rely on the lower forecasts offered by DRA for setting ARA allowances. Although these escalation rates are lower than PG&E forecasts and may not precisely track its actual health plan costs, we conclude that as part of a total attrition package, the adopted escalation rates offer a reasonable and balanced result.

12.3.3. Materials and Services

We adopt PG&E's proposed ARA allowance for adopted 2014 non-labor operating and maintenance and administrative expenses. These non-labor expenses include property insurance. We apply the Global Insight escalation rates as proposed by PG&E.

12.3.4. Capital Attrition Increases

PG&E's proposal would increase attrition year rates by escalating test-year capital additions, including related changes in depreciation levels and deferred taxes. PG&E would hold capital additions constant through 2015-2016 in real terms, although PG&E expects to make higher attrition year capital additions. PG&E applies IHS Global Insights indices to compute attrition year escalation of capital additions by major plant category.

TURN proposes instead an ARA capital additions allowance based on a seven-year average of plant additions in 2012 dollars based on the years 2005-2011.[164] TURN escalates the seven-year average at projected CPI-U to 2015 and 2016 attrition year levels using the IHS Global Insight Cost Planner forecast from fourth quarter 2012. (Exh. DRA-22, Appendix 1).

There are two separate disputes relating to the ARA capital additions methodology: (1) the base year amount of capital additions and (2) the escalation factor(s) to apply to the base year amount. We adopt an ARA base year amount

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[164] TURN excluded Gateway, Colusa, and Humboldt Bay Generating Station costs. These plants achieved commercial operation during 2010-2011, and are thus not an attrition activity. TURN also excluded capital costs for hydro relicensing because the licenses are expected to be issued during the test year for several projects. TURN believes relicensed projects that go into service after 2014 that are not included in test year rates should be treated as adders, as in the Gas Accord process.

for capital additions using a seven-year average as proposed by TURN. We apply an average covering the 2008-2014 period, however, rather than a 2005-2011 period. We also apply escalation factors based on the industry-specific indices proposed by PG&E, however, rather than based on the CPI as proposed by TURN.

Use of an historical average is consistent with the approach applied in the past, and normalizes actual utility spending variations over time. Without conducting full-scale review of 2015 and 2016 capital spending requirements, reliance on historical averages offers a reasonable outcome.

We find insufficient basis to rely on PG&E's assumption that 100% of test year additions should also constitute the basis for trending each of the attrition years. To some degree, accepting PG&E's attrition assumption tends to encourage a "self-fulfilling prophecy," as characterized by TURN, whereby higher spending occurs between test years because the spending gets authorized.

By moderating attrition year capital spending allowances in comparison to test year increases, PG&E has a stronger incentive to find ways to curb the rate of spending growth. Also, while PG&E's attrition methodology focuses on protecting shareholders, it doesn't adequately address the cumulative adverse burdens on customers of absorbing such large attrition increases on top of significant test year increases. We conclude that use of a seven year average better balances the interests of both ratepayers as well as shareholders than does PG&E's methodology.

We recognize that PG&E's claims that setting attrition year capital funding levels well below test year levels is illogical and inefficient. PG&E's criticisms, however, presuppose that its 2015-2016 spending estimates are reasonable.

PG&E claims that 2015 and 2016 capital investment levels will be much higher than a seven-year historic average.

Yet, while test year additions have been scrutinized in detail in this proceeding, PG&E's forecast of attrition year capital additions have not received such scrutiny. We have made limited findings on aspects of PG&E's capital spending for 2015-2016, as discussed in prior sections of this decision, but have not scrutinized the overall reasonableness of 2015 or 2016 capital spending budgets. Given the lack of comprehensive scrutiny of 2015 and 2016 capital spending requirements, PG&E's claims about increased spending requirements for 2015 and 2016 remain unsubstantiated. As a result, we find insufficient basis to accept PG&E's claims that use of historical averages would be illogical, inefficient, or unreasonable. We acknowledge that TURN's methodology does not necessarily cover all attrition year capital expenditures that PG&E may ultimately find prudent. Over several GRC cycles, however, the Commission has not closely covered the utility's claimed attrition revenue requirements. In this regard, the following observations in D.09-03-025 relating to SCE are relevant to the ARA proposals before us here:

> As we repeatedly observed in prior decisions, there is a fundamental problem with budget-based ratemaking that boils down to the fact that budgets are not always implemented as planned. In addition, no party other than SCE provided or analyzed detailed post-TY plant addition forecasts in determining increases. We cannot fault other parties for not recommending detailed PTYR budgets . . . [it] imposes a significant burden on resources.

PG&E also claims that TURN's methodology relates to a past era when the Commission was discouraging additional utility investment. PG&E claims that

escalating the test year additions by a small but fixed amount, is more in line with reasonable future capital spending expectations during the attrition period.

In response to PG&E, TURN presents a chart showing that over the entire period that attrition mechanisms have been used, plant growth has not depended upon base revenue requirement growth nor has plant growth directly driven base revenue requirement growth. As a result, TURN argues that the cost of service type attrition mechanism proposed by PG&E is not required in order to support growth in PG&E's net utility plant. TURN's chart shows that, in percentage terms, the level of plant additions during much of the last decade is not materially different than the level of increases during the 1980s, excluding years where the nuclear plants came on line. During the 1980s and early 1990s, the Commission regularly used average historical plant excluding major plant additions for the capital portion of an attrition mechanism. Ratemaking for major additions was handled separately. TURN shows that even though the Commission historically has not closely covered projected revenue requirement through an attrition mechanism, rate base has grown during that period. Based on TURN's analysis, we conclude that use of historical averages to set ARA capital remains a viable option for consideration in this proceeding.

While PG&E claims that TURN's proposal would create funding shortfalls, PG&E's ARA methodology carries its own risks of creating funding surpluses. PG&E would simply escalate test-year plant additions as a measure of the attrition-year plant additions. Yet, the 2014 test year rate base already represents a significant increase over the 2011 GRC level. PG&E proposes to further trend 2014 test year estimates of net additions upward at industry escalation rates for an additional two years. By further escalating test-year plant estimates, there is a risk of over estimating required attrition year funding.

Although we derive a capital attrition base amount using a seven-year average, we shall use an average of 2008-2014, incorporating our adopted forecast amounts. Use of a more recent seven-year period offers a more robust, forecast relative to TURN's proposal based on the 2005-2011 period. Also, we decline to adopt TURN's use of the CPI to escalate the seven year average from 2012 to 2015-2016 dollar values. Although the CPI may reasonably measure price inflation faced by consumers, it does not measure price escalation for goods and services procured by an energy utility. We find PG&E's approach preferable to TURN's with respect to the escalation factors to apply to the base year amount.

We cannot rely on the outcomes in the four prior GRC settlement agreements cited by DRA as the basis for using the CPI for attrition year escalation this proceeding. The settlements are not precedential. Similarly, five of the six cases TURN references were settlements that were non-precedential.[165] Although prior settlements indicate that a CPI-based approach under certain circumstances may be reasonable as part of an overall settlement, we cannot rely on such settlements to assess whether the CPI or another index, standing alone, is reasonable. Commission rule 12.5 states that settlements are not precedential unless the Commission expressly provides otherwise.

Accordingly, instead of applying the CPI-U, we apply the capital escalation factors by plant category for 2015 and 2016, as found in PG&E's

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[165] The one case cited by TURN that did not involve a settlement was the Sempra Energy (Sempra) 2012 GRC. In that case, Sempra requested a different mechanism, primarily based on escalation of test-year revenues without a separate capital cost computation. Consequently, the Sempra 2012 GRC decision does not provide a comparable basis for evaluating PG&E's proposal for a capital cost attrition component.

update exhibit (Exh. 375 (PG&E-32). These escalation factors are based upon the IHG Global Insights Power Planner forecast. We adopt use of these capital cost factors to escalate the historic average of capital expenditures to 2015 and 2016 values.

By applying these escalation factors, we make some allowance for higher costs due to inflation but do not capture increases driven by the need to complete additional units of work due to connecting new customers and replacing aging infrastructure. By limiting funding in this way, we provide incentives for PG&E to stretch to achieve additional efficiencies. PG&E will have to achieve productivity to offset additional costs in order to earn its authorized rate of return. On balance, we conclude that the use of a seven-year average from 2008-2014, escalated using plant specific factors, offers an appropriate balance among the conflicting proposals for capital-related attrition.

12.3.5. Z-Factor Adjustments

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. PG&E proposes a Z-factor mechanism based generally on the criteria as previously identified in D.05-03-023, as applied to SDG&E. The criteria for a Z-factor's occurrence as identified in D.05-03-023 are:

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.

PG&E supports adoption of these criteria with two exceptions, however, to include changes due to: (1) postal rates; (2) franchise fees; (3) income tax rates and other tax changes which are part of the same or related tax legislation; (4) payroll taxes; and (5) ad valorem taxes. PG&E argues that under the Z-factor criteria adopted for SDG&E in D.05-03-023, these sorts of changes would be excluded. PG&E identifies two criteria in particular: (1) the costs are not a normal part of doing business" and (2) "an event affects the utility disproportionately." PG&E claims that these criteria would apply to all of the exogenous factors proposed by PG&E as exceptions. All of the factors PG&E has identified could arguably be a normal part of doing business (under criteria 4) and would not likely affect PG&E disproportionately (under criteria 5).

PG&E claims its proposed exceptions are consistent with Commission objectives for incorporating exogenous events, but are excluded because of broadly stated Commission criteria identified in D.05-03-023. PG&E claims the specified exceptions it identifies are virtually the same as exogenous adjustments previously allowed by the Commission for attrition and currently allowed as part of the test year update filing.

We adopt a Z-Factor mechanism for 2015 and 2016 attrition years for PG&E, similar to that previously authorized in prior proceedings. We approve the $10 million deductible amount per Z-factor event, as proposed by PG&E. PG&E does not dispute that past Z-factor adjustments have applied exclusively to the attrition years and PG&E does not object to DRA's proposal for limiting

Z-factor adjustments only to the attrition years in this GRC. In line with this agreement, we limit Z-factor adjustments exclusively to the 2015 and 2016 attrition years.

DRA objects to granting an exception for certain exogenous changes that would not meet the criteria outlined in D.05-03-023. The exceptions proposed by PG&E include changes in: (1) postage rates; (2) franchise fees; (3) income tax rates and other changes which are part of the same or related tax legislation; (4) payroll taxes; and (5) *ad valorem* taxes.

We decline to grant PG&E's request to deviate from the criteria previously adopted to qualify for Z-factor treatment. PG&E claims criterion (4) requires that the costs not be a part of normal business operations. We find, however, that criterion (4) actually affirms that that the Z-factor cost should be a part of normal operations. The adopted Z-factor criteria are long standing, dating back to D.94-06-011 as originally recognized in D.89-10-031. (*See* Findings of Facts 24 and 25, D.96-09-092 (68 CPUC2d, 275, 311).) We believe that PG&E should be bound to the same Z-factor criteria we have traditionally applied to all of the other utilities.

12.3.6. Other Miscellaneous Attrition Adjustments

Due to the uncertainties relating to implementation of a new leak survey technology, PG&E is proposing that additional costs for leak survey and repair incurred during 2015 and 2016 be treated through a balancing account mechanism. We separately address this balancing account proposal, and the post-test year treatment for natural gas leak repair costs in Section 3 of the decision.

PG&E also proposes to reduce the 2015 attrition amounts by $20,000,000 for the effects of DOE litigation proceeds which is carried into 2016, consistent with the provisions of the settlement agreement discussed in Section 6.6.1 and as adopted in Appendix F. We adopt this proposal in conjunction with our approval of the settlement agreement.

We are also adopting balancing account treatment for the costs relating to FERC relicensing of various capital projects, as previously discussed in Section 5 of this decision.

Depending on Costs that are subsequently recorded in these balancing accounts the amount of ARA will be adjusted accordingly.

13. Settlements and Joint Proposals

Although most of the disputes in this GRC were litigated with no proposed settlements among parties, PG&E did enter into a series of settlements and joint proposals with certain parties on certain limited issues in this proceeding. We review these settlements and joint proposals in this section.

The Commission has long favored the settlement of disputes. This policy supports many worthwhile goals, including reducing litigation costs, conserving scarce resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.[166] Although we favor the settlement of disputes, Rule 12.2 provides that the Commission will not approve a settlement unless it is reasonable in light of the whole record, consistent with the law, and in the public interest.

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[166] D.05-03-022, mimeo. at 7-8.

All of the proposed settlements and joint proposals submitted in this GRC are uncontested except for the one addressing PPP cost allocation which is opposed by EPUC. The Commission's policy is that contested settlements should be subject to more scrutiny compared to an all-party settlement. As explained in D.02-01-041:

> In judging the reasonableness of a proposed settlement, we have sometimes inclined to find reasonable a settlement that has the unanimous support of all active parties in the proceeding. In contrast, a contested settlement is not entitled to any greater weight or deference merely by virtue of its label as a settlement; it is merely the joint position of the sponsoring parties, and its reasonableness must be thoroughly demonstrated by the record. (D.02-01-041, *mimeo.*, at 13.)

Accordingly, for the proposed settlement which is contested, we consider the merits of the objections raised by EPUC, and the substantive merits of the underlying disposition of the issues. For the uncontested settlements, we conclude that they meet the requisite criteria for adoption. In accordance with Rule 12, we find that each of these settlements is reasonable in light of the whole record, consistent with the law, and in the public interest. We accordingly adopt the settlements, as summarized below, and as set forth in Appendix F-1 through F-5.

13.1. Joint Proposal on Accessibility Issues

The Center for Accessible Technology (CforAT) and PG&E presented a joint proposal to address and improve accessibility issues as set forth in PG&E's Opening Testimony.[167] The joint proposal calls for PG&E to spend $1.5 million

[167] *See* Exh. 22 (PG&E-5) Ch. 11.

each year for 2014-2016 on designated incremental activities in various areas, including: ensuring accessibility at local offices, pay stations, and construction sites; improving accessibility of communications (e.g., web, large print); hiring a coordinator to work on disability issues; and reporting on accessibility activities and spending. No party commented on the joint proposal.

Disability Rights Advocates and PG&E jointly developed Memoranda of Understanding (MOU) to address accessibility issues in PG&E's last two GRCs. We adopted each of those MOUs in PG&E's 2007 and 2011 GRCs, respectively. Similarly, C for AT and PG&E have discussed issues of common interest regarding accessibility in this current proceeding and submitted a joint proposal in this proceeding, as set forth in Exhibit 22 (PG&E-5).

We conclude that the joint proposal of PG&E and CforAT to improve accessibility issues is a significant advancement over the parties' prior MOU initiatives in addressing disability issues. The current joint proposal increases the scope of activities to be undertaken and takes steps to institutionalize the improvements within PG&E. Accordingly, we find that the record supports adoption of the joint proposal and PG&E's related forecast. The terms of the joint proposal are adopted as set forth in Appendix F4. Among its provisions, PG&E is required to:

(a) Commit to incremental spending of $1.5 million per year on designated activities to improve accessibility as set forth in the joint proposal.

(b) Prepare and distribute to the Center for Accessible Technology, and any other interested parties, an annual report on its activities and spending to promote accessibility as specified in the joint proposal. The report is due by the end of April of each preceding calendar.

(c) Hire a new Disability Coordinator to be responsible for coordinating and shaping Company-wide strategies to improve accessibility.

(d) Meet with the Center for Accessible Technology, and any other interested parties, in accordance with the schedule in the joint proposal to discuss planned accessibility spending for the upcoming calendar year.

The $1.5 million spending target identified in the joint proposal has been included in PG&E's revenue requirement forecast through a high-level adjustment in the RO Model. We find the joint proposal reasonable and hereby adopt it. We approve the proposed $1.5 million of incremental funding and direct PG&E to implement the provisions of the joint proposal as set forth in Appendix F-4.

13.2. Settlement on Customer Outreach for Communities of Color and Related Initiatives

On May 24, 2013, the National Asian American Coalition, the Ecumenical Center for Black Church Studies, the Chinese American Institute for Empowerment, the National Hmong American Farmers, the Burmese American Institute for Corporate Responsibility (*i.e.,* the "Joint Parties"), together with PG&E, filed a motion for adoption of a settlement agreement. This Settlement Agreement resolves all disputed issues raised by the Joint Parties in this proceeding relating to PG&E's programs for customer rate education and outreach.

In its opening testimony, PG&E forecasted $7.25 million for "Targeted Rate Education and Outreach" for residential customers, relating to a variety of

activities outlined in that testimony.[168] In their January 8, 2013 motion seeking party status, the Joint Parties raised issues concerning consumer protection for people of color and low-income communities relating to PG&E's education and outreach programs, in particular, highlighting the need for linguistically and culturally appropriate education to accompany such programs. DRA expressed concerns regarding incremental funding for such activities. Greenlining expressed support for greater outreach to limited English-proficient customers.

On June 24, 2013, Greenlining, TURN and CforAT submitted comments in support of this Settlement Agreement if it is modified to include (1) requirements related to the information gained from expanded customer surveys; (2) reporting requirements regarding the expenditure of funding dedicated to providing culturally and/or linguistically appropriate outreach to residential customers about rate design options; and (3) expansion of the subset of customers to be targeted with these funds to include "hard-to- reach" customers. On July 8, 2013, PG&E and Joint Parties filed a reply supporting approval of the settlement incorporating the changes recommended by TURN/CforAT.

Under the terms of the Settlement, as reflected to incorporate parties' June 24, 2013 comments, PG&E thus agrees to the following commitments:

(a) To expand current surveys of its service area that gauge customer understanding of safety and low-income bill assistance programs.

(b) To devote 45% of all Customer Care Targeted Residential Rate Education and Outreach funding up to $2.8 million per year for specified outreach activities.

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[168] Exh. 22 (PG&E -5) at 7-33. Table 7-6, Line 1.

(c) To invite low –income and community-of-color advocates to participate on an existing customer advisory panel as specified in the Settlement.

(d) To provide testimony in the 2017 GRC on its efforts to engage with community –based organizations, to hire minority-owned businesses for auditing work, and to promote diverse hiring at all levels.

(e) To put out for bid its overall auditing function prior to 2017.

(f) To meet with key diverse business enterprise organizations attending the annual GO 156 en banc proceedings, to discuss cooperative methods for achieving GO 156 goals and other issues as specified in the Settlement.

Discussion

With incorporation of the recommended changes, as noted above, no party opposes the settlement. We find its terms reasonable and adopt it, as set forth in Appendix F-1.

The Settlement is reasonable in light of the whole record, consistent with law, and in the public interest. Accordingly, we direct PG&E to comply with all of terms of the adopted settlement, including the additional provisions proposed in the July 8, 2013, comments, as identified above. The specific provisions of the adopted settlement, including the provisions incorporated in response to filed comments, are set forth in Appendix F.

13.3. Small Business Utility Advocates Settlement

On June 26, 2013, the Small Business Utility Advocates (SBUA) and PG&E executed and moved for adoption of a settlement agreement of all issues disputed between SBUA and PG&E. The settlement agreement calls for implementation of activities in various areas relating to small businesses, including more outreach and support, tracking systems, supply chain

sustainability, small electric generators, encouraging innovative energy solutions, greenhouse gases and carbon offsets, and economic development.

Discussion

No party commented on the SBUA/PG&E settlement agreement. We find the terms reasonable in light of the whole record, consistent with the law, and in the public interest, and adopt the SBUA/PG&E settlement agreement as set forth in Appendix F-2. We direct PG&E to implement the terms of the SBUA settlement agreement.

13.4. Joint Proposal on DOE Litigation Refund Treatment

On August 6, 2013, MEA, TURN and PG&E submitted a joint exhibit setting forth proposed ratemaking treatment for the Department of Energy (DOE) litigation refund. No party opposes the joint proposal. We find the joint proposal reasonable and adopt it, as further discussed in Section 6.6.1. The adopted provisions of the proposal are set forth in Appendix F-5. We direct PG&E to implement the procedures for the accounting and ratemaking treatment of DOE litigation refund proceeds as set forth in Appendix F-5.

13.5. Settlement Regarding Allocation Methodology for Public Purpose Program Labor

On September 6, 2013, PG&E, MEA, and TURN jointly filed a motion for adoption of a settlement on an allocation methodology for PPP Labor. As further discussed at Section 9.10 of this decision, we find the settlement reasonable in light of the whole record, consistent with the law, and in the public interest and adopt it as set forth in Appendix F.

14. Assignment of Proceeding

Michel P. Florio is the assigned Commissioner, and Thomas R. Pulsifer is the assigned ALJ in this proceeding.

15. Comments on the Proposed Decision

The proposed decision of ALJ Thomas R. Pulsifer in this matter was mailed to the parties in accordance with Pub. Util. Code § 311, and comments were allowed pursuant to Rule 14.3. Opening comments were filed on July 8, 2014, and reply comments were filed on July 14, 2014 by PG&E and several other parties. We have reviewed the comments, and incorporated appropriate corrections, clarifications, and revisions in various sections in finalizing this decision.

Findings of Fact

1. As a basis for its requested increases in adopted GRC revenue requirements, PG&E developed forecasts based on a 2011 recorded base year, with cost estimates covering 2012 through 2014 to derive a 2014 test year forecast.

2. PG&E proposed a separate methodology based on simplified assumptions to support post-test year revenue requirement increases for 2015 and 2016 to address attrition relating to expenses and capital expenditures.

3. Although PG&E presented capital forecasts relating to activity during 2015 and 2016, no other party undertook a comprehensive scrutiny of 2015 and 2016 capital expenditure forecasts.

4. In compliance with Ordering Paragraph 37 of D.11-05-018, PG&E included descriptions and forecasts of cost savings for its new types of costs. For those new projects where PG&E expects no cost savings that can be quantified, PG&E provided alternative reasons as claimed justification for the project.

5. Pursuant to the Executive Director's letter, PG&E was directed to include in this GRC: (a) a risk assessment of its entire system that underlies its GRC rate requests to satisfy the GRC focus on safety, (b) to provide a comparison to industry best practices, and (c) to provide testimony to identify and prioritize areas of risk and include the underlying rationale for PG&E's assessment.

6. Pursuant to the March 5, 2012 letter from the Executive Director, the Commission's Safety and Enforcement Division commissioned reports from independent consultants to evaluate PG&E's electric and gas operations from a safety and risk perspective. The reports of the Liberty Group (Liberty) and Cycla Corporation (Cycla), both expert independent consultants, were entered into the evidentiary record in this proceeding.

7. The Liberty report addressed safety and security risks that can affect safety in non-nuclear power generation and in electricity distribution (i.e., excluding transmission).

8. The Cycla report addressed safety and security risks in the context of PG&E's natural gas distribution system.

9. The Safety and Enforcement Division separately commissioned a report from Overland Consulting which provided the results of Overland's focused financial audit of PG&E's Gas Distribution operations. The Overland Report was issued by ALJ Ruling and made a part of the record.

10. The Liberty consultants found that the expectations created in the Executive Director's March 5, 2012 letter anticipate a use of risk assessment that is beyond what one currently finds in the industry.

11. The Liberty consultants found that although PG&E's proposed GRC electric department projects and programs address important safety risks, PG&E

has generally not demonstrated analytically that the benefits of proposed safety and security risk mitigation justify their costs.

12. Liberty consultants found that, although PG&E has made material progress in enhancing its risk management program, PG&E's risk assessments are not sufficiently developed to serve as a robust basis for assessing probabilities and consequences of failures due to safety and security risks.

13. In the aftermath of the September 2010 San Bruno natural gas pipeline incident, PG&E undertook corporate-wide programs aimed at better identification and mitigation of business risks, including those having safety implications.

14. In selecting measures to mitigate identified safety and reliability risks, PG&E chose the measures that move it toward first quartile safety performance and considered cost in determining the pace of implementing such measures.

15. While PG&E identified and quantified spending on safety and security measures in its filing, PG&E overused the "safety" label. Much of what PG&E designates as "safety" projects and programs in this GRC falls under what other parties consider to be baseline and reliability work.

16. Certain programs and activities underlying PG&E's forecast are required by law, are a necessary prerequisite to achieving public policy goals, or involve new technology where there is insufficient data to measure benefits. Some of PG&E's claimed program benefits (e.g., improved safety and reliability) are not easily measureable.

17. Several parties and participants at the public participation hearings, raised concerns about the level of PG&E's proposed rate increases, particularly in light of continued economic challenges faced by many customers.

18. PG&E forecasts expense for 2014 of $461.1 million to: (1) own, operate, and maintain gas distribution plant and a portion of common and general plant; (2) acquire gas supplies for core gas customers; and (3) provide services to gas customers.

19. PG&E's proposed funding includes programs: (1) to improve visibility of its gas distribution system to identify and respond to problems more quickly; and (2) to improve leak detection, enabling leaks to be fixed faster and thus mitigating safety risks.

20. The largest drivers for gas distribution expense increases are gas leak repair, field services and dispatch to meet emergency response goals, the Distribution Integrity Management Program, and implementing related new technology.

21. PG&E forecasts 2014 capital expenditures for gas distribution of $842 million, primarily due to accelerated pipeline replacement and a new Gas Distribution Control Center, new buildings, new customer connections, work requested by others, and new technology.

22. PG&E justifies the need for a new Gas Distribution Control Center and for 25 new positions to staff it., It is reasonable to forecast 2014 funding for the 25 new positions while forecasting reduced 2014 funding for capital expenditures, however, based on a uncertainties regarding the schedule for implementation compared to PG&E's forecast.

23. PG&E forecasts capital expenditures of $220 million over the 2012-2016 period to install remote monitoring instrumentation and control devices on its gas distribution system.

24. Since PG&E has overcome road blocks encountered in 2012 that delayed spending for remote monitoring and control devices for its gas distribution,

PG&E's forecast for these expenditures for 2013 is reasonable. Given the complexities and magnitude of remaining work involved, relating particularly to software implementation, however, it is reasonable to apply a 14% reduction in PG&E's 2014 capital forecast consistent with reductions applied in this decision to other Information Technology project forecasts, resulting in a capital reduction of $8.7 million in MWC 4A.

25. PG&E's proposed time frame and forecasted number of records, which relates to the gas distribution mapping project to collect, transport, standardize, and electronically archive over 15,000 linear feet of gas distribution paper as-built records and service records into its enterprise wide records center, is reasonable. PG&E, however, has not justified the need for $1.3 million contingency funding, or the need for more than 80 mappers.

26. PG&E forecasts $47.25 million for its Gas Distribution Integrity Management Program to comply with federal gas pipeline safety requirements and enhance safety and reliability.

27. PG&E's forecast of $1.97 million for enhanced leak surveys is reasonable, and covers new activities that are not covered under current leak survey work.

28. PG&E's cross-bore sewer remediation project mitigates a major safety risk by identifying where cross bores may have occurred and by relocating the line, where necessary. PG&E's cost forecast for the program is reasonable, except for an adjustment based on the $5,000 unit cost for bell hole excavations calculated by DRA.

29. PG&E's forecast of $4.5 million for DIMP internal management resources is reasonable.

30. While some funding is warranted for DIMP emergent work, that is, miscellaneous projects not yet identified, TURN's forecast of $4.7 million is more

reasonable than PG&E's $10 million forecast. TURN's DIMP emergent work forecast is based on costs incurred between 2011 and 2013 not included in the 2011 forecast.

31. PG&E's forecast of $7.3 million to identify areas with clusters of plastic tee caps and to proactively repair them to prevent future leaks is reasonable, and the program mitigates a known safety risk.

32. PG&E forecasts $83.825 million in 2014 expense for Pipe, Meter, and other Preventive Maintenance to forestall equipment degradation and failure and promote safety. Costs include locating and marking facilities for third parties, cathodic protection, maintenance for regulator stations, mains and services, and valves, atmospheric corrosion monitoring and remediation, meter protection, and natural gas vehicle maintenance.

33. PG&E's forecast of $39 million for locate and mark activities expense is reasonable. These activities reduce damage to underground facilities caused by accidental dig-ins.

34. PG&E's forecast of $28.3 million for 2014 is reasonable covering gas distribution preventive maintenance for (a) regulator stations, mains and services, and distribution valves; (b) service valve replacement; (c) atmospheric corrosion; and (d) special projects.

35. Pipeline safety regulations require periodic surveys on PG&E's distribution system to find gas leaks.

36. PG&E forecasts $33.84 million for gas distribution leak survey expense and $102.14 million for corrective maintenance, of which $93.44 million is for repairing leaks not caused by dig-ins.

37. PG&E's 2014 forecast of corrective pipeline maintenance (MWC FI) is reasonable, except for a reduction of $27.8 million, as proposed by TURN, based

on TURN's leak find rate of 2.457%, and incorporating a five-year leak survey cycle.

38. PG&E's projected increase in gas distribution leak survey and corrective maintenance expense increase is primarily based on: (1) a proposed move from a five-year to a three-year routine leak survey cycle, (2) locating more leaks to repair since more than twice as much time will have passed since the prior leak survey compared to the 2011 test year, and a higher leak find rate for traditional surveying, with rapid repair of Grade 2 and Grade 2+ leaks and (3) use of the Picarro Surveyor, which is expected to find more leaks than traditional methods.

39. PG&E plans to implement various enhancements to locate and grade gas distribution pipe leaks to improve system safety, and seeks to accelerate from a five-year to a three-year cycle for routine leak surveys. PG&E plans to focus resources in areas with known high leak rates where clusters of leaks have been repaired.

40. PG&E traditionally performs routine leak surveys by foot, but is phasing in use of the Picarro Surveyor which is 1,000 times more sensitive than current equipment, providing almost a three-fold increase in leak detection effectiveness and efficiency.

41. PG&E plans to use Picarro for surveying the highest risk pipe starting with three divisions in 2014.

42. Since SB 705 provides no definition of industry best practices, PG&E proposes its own standard. If 25% or more of industry operators are doing a particular safety practice, PG&E defines the practice of those safety operators as an industry best practice.

43. PG&E presented a benchmarking study that shows 25% or more of the operators in the study conduct leak surveys at least once every three years.

Based on that study, PG&E defines surveying its entire gas distribution system at least once every three year as a best practice.

44. Increasing the routine leak survey cycle frequency is only one of several strategies PG&E can use to detect and repair leaks more effectively. PG&E has not evaluated the best rate of phase-in of the various measures proposed to reduce the number of hazardous leaks (e.g., more cluster surveys, pipe replacement, more rapid response to reported leaks, etc.)

45. PG&E's claim that a three-year survey cycle is required to meet industry best practice is based on one aspect of other operators' leak survey programs. Operators using a three-year cycle, however, have not implemented use of the Picarro Surveyer, and probably have not implemented other measures utilized by PG&E such as cluster surveying.

46. Regarding the controversy over whether PG&E should conduct routine leak surveys on a specific cycle frequency, the choice of a specific leak cycle frequency is ultimately a management decision that is PG&E's responsibility. For purpose of setting ratepayer funding for leak survey and repair expenses, however, it is reasonable to adopt a 2014 funding based on the assumptions predicated on continuation of a five-year routine leak survey, but with flexibility for PG&E to recover its reasonable expenses that exceed this minimum level funded in the 2014 revenue requirement through the balancing account mechanism up to a prescribed cap.

47. For purposes of providing flexibility to implement its proposed range of enhanced leak survey and repair techniques, it is reasonable to limit cost recovery to a maximum rate cap for the leak survey and repair balancing account at a level not to exceed PG&E's forecast annual amount for leak survey and repair. Although PG&E's forecast assumes a three-year routine leak survey cycle, the

actual amount that PG&E may ultimately recover through balancing account adjustments will depend on how PG&E integrates leak survey frequencies with other enhanced leak detection and repair strategies

48. Based on continuation of a five-year routine leak survey cycle, PG&E's leak survey expense forecast for MWC DE, MAT DEA, declines to $11.6 million.

49. PG&E proposes balancing account treatment to adjust for differences between authorized and actual expenses incurred relating to MWC DE for natural gas distribution leak surveys, MWC FI for leak repairs, Maintenance Activity Types MAT HY7 for meter set leak repairs, MAT FHK for atmospheric corrosion inspection costs, and tee cap repairs (embedded in MAT JSL). Implementation of a two-way balancing account is a reasonable vehicle to deal with the uncertainty as to how many leaks will be found and repaired, particularly due to all the new leak survey techniques to be used.

50. No party disputed PG&E's average unit cost forecasts for the costs proposed to be recovered through the leak survey and repair balancing account. It is reasonable to adopt average unit cost forecasts applicable to the balancing account as follows: MAT DEA, $15; MAT DED, $230; MAT FIB, $2,492; MAT FIF, $2,994; MAT FIG, $6,453; MAT FIH, $620; MAT FII, $1,895; MAT FIJ, $1,248; MAT FIK, $386; MAT FIP, $3,184; MAT HY7, $131; and tee cap repairs embedded within MAT JS, $7,300.

51. It is reasonable to adopt annualized cost recovery caps with respect to each of the individual cost elements subject to inclusion in the leak survey and repair balancing account, as set forth in Ordering Paragraph 7.

52. PG&E's Field Services and Response expense forecast includes $105.956 million for field services and $7.756 million for atmospheric corrosion work and meter set leak repair. The forecast increase of $37 million over 2011

levels is primarily to cover more staffing to respond to customer-reported gas odors within 30 minutes 75% of the time and within 60 minutes 99% of the time.

53. PG&E forecasts $31.5 million for pilot relights on customers' gas appliances based on 2011 base year amounts. TURN's proposed reduction of $6.5 million for pilot relight expenses is reasonable based on a 2007-2012 cost trend. The mild winter in 2012 is not sufficient basis to dismiss TURN's calculation of a lower number of pilot relights.

54. PG&E forecasts $105.96 million for the addition of 120 gas service representatives (GSRs), six supervisors and six clerks to investigate customer reports of gas odors consistent with gas industry best practices. PG&E forecast 40 GSRs added in 2012 and 80 more GSRs in 2014.

55. Although PG&E claims its needs an additional 80 gas service representatives during 2014 to meet faster response time goals planned to take effect in 2015, there is uncertainty as to whether PG&E has adequately reflected appropriate efficiencies in adding such a staffing increase.

56. Cycla believes that inefficiencies related to adding field service response personnel during 2011 may have occurred, given cost escalations between 2010 and 2011. Cycla does not find that the impacts of increasing GSR staff as forecast by PG&E have been demonstrated.

57. PG&E makes a 2014 capital forecast of $531.595 million for gas distribution tools and equipment, pipeline replacement, natural gas vehicles, capacity reliability, leak replacement emergency response, and high pressure regulator replacement.

58. PG&E's Gas Distribution Pipeline Replacement Program is designed to reduce pipeline leaks and to reduce the risk of weld, pipe, or joint failure due to seismic stresses.

59. The current pace of PG&E's pipeline replacement must increase, or service quality and safety will decline over time. Increased funding for a more rapid pace of pipeline replacement in this GRC is constrained, however, by limits on what current ratepayers can reasonably afford to pay in relation to the degree of risk mitigation involved, Although PG&E proposes a significant increase in the rate of pipeline replacement, however, PG&E has not developed a risk-informed position on the optimal rate of pipeline replacement.

60. Beginning in 2014, PG&E plans to replace about 160 miles of distribution pipeline per year, including doubling steel pipe replacement to 60 miles per year, more than doubling steel pipe replacement costs (to $163 million), and replacing plastic pipe (primarily Aldyl-A) at a similar spending level ($166 million).

61. TURN's pipeline replacement funding proposal provides a reasonable balance between containing cost increases while mitigating pipeline safety risk. TURN's proposed funding keeps current steel pipe replacement at 27 miles per year while redirecting more funding to plastic pipe replacement at 139 miles per year. TURN's forecast assumes steel pipe replacement continues at 27 miles per year at an average rate of $516 per foot and plastic pipe replacement increases to139 miles per year at an average rate of $314 per foot.

62. TURN's proposed funding is sufficient to replace high priority steel pipe within three years, and results in 2014 capital spending 241 % above 2011 levels, while reducing PG&E's 2014 forecast by $25.3 million. It is reasonable to adopt a 2014 capital forecast for MWC 14 of $305.858 million (composed of $230.451 million for Aldyl-A, $73.561 million for steel, and $1.846 million for copper pipe), based on TURN's proposal for pipeline replacement.

63. PG&E forecasts $62.7 million, $72.439 million and $128.1 million in 2012, 2013, and 2014, respectively, for MWC 50, Gas Distribution Reliability, for capital

installation or replacement of aging gas facilities to improve system safety and reliability, replace aging facilities, and maintain compliance with safety regulations.

64. Consistent with a five-year leak survey cycle, it is reasonable to reduce PG&E's forecast for MWC 50 by $2.051 million for 2014, as calculated by TURN, and further reduce costs by 13.91 million to reflect planned installation of emergency shut-down valves over six years, rather than three. Extending installation over six years mitigates impacts on customers of such a large cost increase, and alleviates pressure on PG&E's ability to fund competing resources and high-priority programs.

65. PG&E forecasts $42.0 million in 2012, $50.0 million in 2013, and $51.2 million in 2014 for Gas Distribution Leak Replacement/High Pressure Regulator (HPR) Replacement.

66. PG&E forecasts 2014 capital expenditures of $83 million to cover installation of infrastructure to connect new customers to the gas system and to accommodate increased load from existing customers.

67. PG&E forecasts technical training development expense of $12.69 million and $2.5 million for R&D and Innovation activities to identify new or improved means of enhancing operation, safety and efficiency.

68. PG&E forecasts $16.69 million in 2014 capital expenditures and $10.3 million expense for the Pathfinder Project to convert gas distribution asset and maintenance information from legacy and paper-based systems to SAP and GIS systems.

69. PG&E forecasts capital expenditures for 2012-2014 of $37.89 million, $53.499 million, and $70.67 million, respectively for Electric Operations

Technology and $12.07 million in 2014 expense to enhance technology applications and deploy new technologies.

70. PG&E's Electric Distribution Geographic Information System (GIS)/Asset Management capital forecast is $20.6 million for 2012, $32.3 million in 2013, $27.8 million in 2014, and $1.8 million in 2014 expenses. This project is to validate, enhance, and convert legacy mapping and connectivity data to a single GIS to maintain geospatial and other asset attributes.

71. PG&E's forecasts Electric Distribution Workforce Mobilization and Scheduling Technology projects capital funding for 2012 of $7.2 million, for 2013 of $11.1 million, and $14.8 million in 2014, to improve scheduling and dispatching efficiencies, records accuracy, and coordination with local emergency response teams in emergency and outage situations.

72. While the Workforce Mobilization projects offer prospects for cost savings and qualitative benefits, PG&E's proposed spending levels are excessive in relation to potential benefits, and certain funding reductions, as proposed by TURN, are appropriate.

73. PG&E's data historian software application provides central data archiving and analysis generated by the Supervisory Control and Data Acquisition (SCADA) system.

74. PG&E forecasts capital of $12.3 million in 2014, and $0.2 million in 2014 expenses for its Data Historian to replace existing software with an upgraded industry standard data historian application to provide more granular data and more powerful analytical tools.

75. PG&E's data historian capabilities lag the industry and need upgrading to keep up with increased SCADA functionality. PG&E's data historian project will

provide safety and reliability benefits by reducing equipment failure, fire risk, and outage durations.

76. PG&E forecasts $3.9 million in 2014 expense and $3.8 million in 2014 capital for the Customer Connection Online (CCO) project which builds upon SAP Work Management enhancements to improve work order management and tracking.

77. The new CCO tools enhance website capabilities and integration to back end systems to provide customers timely and direct access to service request status. Existing online tools do not adequately meet customer needs for requesting and monitoring service requests.

78. PG&E forecasts $31.12 million for Electric Mapping and Records Management expenses for 2014, which includes four new initiatives: (1) Records Quality Assurance Program; (2) Field Asset Inventory; (3) Conversion of Paper Records to Electronic Format; and (4) Electronic Records Update to Standard Format.

79. PG&E's existing mapping and asset management systems do not integrate all necessary data sets to support mobile technologies, system modeling, reporting and analysis, and overall asset management. PG&E's mapping and records initiatives will bring PG&E up to acceptable industry standards.

80. PG&E's Electric Distribution Maintenance includes inspection, testing, repair and replacement of distribution facilities, and initiatives to proactively replace aging assets that pose safety and/or reliability risks. PG&E's 2014 increases are primarily due to maintenance on new capital projects e.g., Idle Facilities Removal, Infrared Switch and Conductor and Underground Oil Switch Replacement.

81. For this GRC cycle, it is reasonable to limit capital funding for Idle Facilities Removal to $2 million per year in MWC 2A, as proposed by TURN.

82. PG&E's infrared conductor replacement program provides an important safety enhancement and funding it is appropriate, even though PG&E has not quantified a cost/benefit risk analysis.

83. PG&E's requested funding for overhead conductor replacement forecast in MWC 2A is not duplicative of forecast costs in MWC 08.

84. It is reasonable to reduce PG&E's forecast for Tie-Cable Replacement, COE Cable Replacement to exclude previously deferred maintenance on Tie Cable and COE Cable Replacements. Adopting a 2014 forecast equal to PG&E's 2013 forecast reduces the forecast for 2014 by $37.8 million.

85. PG&E's 2014 forecast expense for Pole Test and Treat, Pole Restoration and Joint Utilities Coordination Programs is $8.5 million higher than 2011 due to an increased number of poles to be inspected during the 2012-2014 period.

86. PG&E conducts pole inspection on a 10-year cycle, with the current cycle scheduled to end in 2014. To complete its 10-year pole inspection cycle by 2014, PG&E increased the number of pole inspections starting in 2012 to work down a backlog of deferred inspections from prior years.

87. Once the backlog is completed, PG&E plans to complete a subsequent 10-year inspection cycle covering 235,000 poles per year. Thus, the expected number of pole inspections PG&E plans to perform annually after 2014 should decrease to 235,000 per year.

88. Although PG&E was authorized funds for pole inspections during prior GRC cycles, PG&E deferred spending on pole inspection work during those cycles in conjunction with performing work in other areas.

89. The portion of 2014 forecast expense for pole inspections that exceeds the 235,000 pole amount constitutes deferred maintenance that was previously funded by ratepayers.

90. For 2014 Pole Replacements, PG&E forecast units of work and unit cost to perform the work. PG&E's forecast of increased units of pole replacements for 2012 and 2013 reflects PG&E's effort to eliminate the backlog of pole replacements that were previously funded but deferred. By 2014, PG&E plans to reach a consistent level of pole replacement work.

91. Because forecasted levels of pole replacements were deferred in previous years, the costs to reduce the backlog of postponed replacements represents deferred maintenance.

92. PG&E requests $25 million in 2014 capital spending to proactively replace potentially hazardous, older-vintage underground oil-filled switches, with related 2014 expense of $1.5 million.

93. To the extent that oil-filled switch failures cause outages, PG&E has not estimated the reliability improvement from its replacement program, or compared hypothetical improvements to the costs of other reliability enhancement programs.

94. Although some level of proactive replacement of oil switches is warranted to mitigate safety risks, PG&E's proposed rate of replacement reflects an unjustified cost burden on ratepayers relative to the mitigation of such risks. Funding replacement of 250 oil switches per year provides some momentum to move forward with proactive replacement to mitigate safety risks, while moderating cost burdens on ratepayers.

95. PG&E's planned installation of upgraded Network SCADA capability on its distribution system in San Francisco and Oakland will allow for detection and

response to equipment overloads to prevent failures before they occur, improving network safety and reliability.

96. Network SCADA monitoring capital cost funding at the levels proposed by PG&E is warranted because the project is critical for safety risk mitigation.

97. PG&E's 2014 forecast for Network Transformer and Protector Replacement work is reasonable given the need for increased spending levels in view of the increased scope of high-rise building work.

98. PG&E forecasts $190 million for Vegetation Management expenses, an increase of 17.6% over 2011 expenses, driven mainly by increased environmental regulatory compliance and increased fire risk reduction work to improve public safety.

99. D.07-03-044 established the Incremental Inspection and Removal Cost Tracking Account Procedure to record incremental inspection and removal costs that PG&E incurs for work required by California Department of Forestry and Fire Protection.

100. PG&E forecasts $10.78 million in 2014 for expenses related to processing of new customer connections. PG&E's assumption of increasing Plug-in Electric Vehicle (PEV) sales is consistent with reported trends.

101. PG&E forecasts capital expenditures in MWC 16 for installation of electric infrastructure to connect new customers to PG&E's distribution system and to accommodate increased load from existing customers, and in MWC 10 for relocation of electric distribution and service facilities at the request of a governmental agency or other third party.

102. There is no inherent inconsistency in forecasting increased subdivision connections while at the same time, backbone connections are increasing at a lower rate. During 2012, backbone connections were decreasing as subdivision

connections were increasing. During the recent economic downturn, many developers stopped building homes after subdivision backbone facilities had already been installed.

103. There is insufficient evidence to indicate that PEV sales will increase significantly over this GRC cycle, considering the findings in the "Joint IOU Electric Load Research Final Report," filed pursuant to D.11-07-029.

104. PG&E's Electric Emergency Recovery Program (ERP) expense forecast of $113.7 million is for electric emergency recovery work. An immediate response is necessary when an outage occurs, a situation is unsafe, or potential for an imminent hazard exists.

105. PG&E's forecast of $54.7 million for Distribution System Operations (DSO) expense covers the monitoring of 720 distribution substations and 140,000 miles of distribution lines.

106. PG&E adequately explained its rationale for deferring spending on the Distribution Control Center (DCC) consolidation project with the result that ratepayer's benefitted from a more cost effective solution.

107. PG&E is not able to accurately forecast extraordinary incremental costs related to catastrophic events. PG&E's proposal for a balancing account for recovery of costs associated with major emergencies that do not qualify for Catastrophic Event Memorandum Account (CEMA) cost recovery is a reasonable way to address this forecasting uncertainty.

108. To meet demand growth and to address equipment overload and voltage issues, PG&E forecasts capital costs for Substation Capacity and Distribution Line and Equipment Capacity for 2013 of $143.8 million and for 2014 of $182.8 million.

109. PG&E's Substation Asset Strategy work covers operation, maintenance, installation and replacement of substation infrastructure. Distribution substations transform high-voltage electricity from the transmission system to lower-voltage electricity for delivery to customers.

110. Liberty found that PG&E's SAS programs are effectively managed, and have no unaddressed safety risks.

111. The Engineering Program primarily supports capital expenditure programs, electric distribution operating functions, and power quality investigations relating to capacity, reliability and operations.

112. PG&E has justified its $18.743 million expense forecast for MAT FZA to proactively identify problems and mitigate safety risks relating to conductor, connectors, and/or design issues that may contribute to downed wires.

113. PG&E's Electric Distribution Reliability Program addresses overall reliability performance, and includes costs for electronic control equipment installation or upgrade, and replacement of deteriorated sections of overhead conductors.

114. PG&E justified its forecast for conductor replacements to mitigate the public and system safety risks of "wire down" events.

115. PG&E forecasts $24.42 million in MWC 08 for line recloser revolving stock. Each new Fault Location, Isolation, and Restoration (FLISR) circuit requires, on average, the installation of three line reclosers. It is reasonable to reduce funding for line recloser revolving stock by 25% to be consistent with the 25% reduction of funding for FLISR/Feeder automation.

116. Funding for FLISR installations is warranted, but with a reduction in 2014 capital funding by approximately 25%,due to the fact that PG&E failed to

justify why it could not address electric reliability matters in an integrated fashion.

117. To fund underground primary distribution cable covering 27,900 circuit miles, and other aspects of its Underground, Asset Management Program, PG&E forecasts capital costs of $72.0 million in 2012, $68.9 million in 2013, and $140.1 million in 2014, primarily to replace underground cables to address aging infrastructure and improve safety.

118. PG&E's capital forecast for Distribution Automation and System Protection is $73.421 million in 2014 and $47.240 million in 2013, to cover installation, upgrade, and replacement of remotely controlled automation and protection equipment, including Supervisory Control and Data Acquisition equipment, also known as SCADA.

119. PG&E has a substantial accumulation of unfunded Rule 20A projects, which allow a city or county to convert existing overhead lines to underground at PG&E's expense. PG&E's forecast for this GRC anticipates eliminating the accumulation of unfunded Rule 20A projects by the end of 2017, while maintaining the current average project duration of seven years.

120. 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.

121. PG&E's light-emitting diode (LED) Streetlight Replacement forecast of $18.6 million in capital costs for 2014 involves replacement of PG&E-owned High Pressure Sodium Vapor (HPSV) streetlights with LED streetlights.

122. Reducing PG&E's funding for the LED Streetlight Replacement, as proposed by DRA and TURN, would significantly delay program

implementation and preclude customers from realizing most of the program's cost savings until after 2017.

123. The record is not sufficiently developed to adopt CCSF's proposal for payment of a deficiency charge to streetlight customers when PG&E fails to meet performance standards for two consecutive months in a municipality.

124. Although PG&E's 2014 forecast for Network Cable Replacement of $21 million reflects a significant increase over past years, the safety risk that is mitigated warrants the increased expenditures.

125. PG&E's requested funding to remove and to proactively replace transfer arm rocker ground main/line (TGRAM/TGRAL) switches for 2014 is justified. These switches create safety risks, and completing their removal is an appropriate measure to promote safety.

126. PG&E forecasts Customer Care expenses for 2014 of $454.6 million, to cover a range of services and programs to meet retail customers' needs, including responding to customer inquiries and preparing customer bills, notices, and payment processing, and to raise customer service standards.

127. PG&E's forecasted $15 million for capital costs and $1.2 million in expenses to expand the Sacramento and Fresno Customer Contact Centers is warranted to address safety concerns in Stockton and parking limitations in the San Jose center.

128. There is insufficient justification to reduce customer wait times to transact business as currently experienced at certain local offices.

129. PG&E has not adequately justified ratepayer funding of $1.487 million in expenses and $3.88 million in capital for local office improvements including relocations and remodels, lobby upgrades, workstation ergonomic improvements, and improved signage.

130. PG&E's proposals for the following are uncontested: (1) use of base year 2011 costs in MWCs IS, EZ, IT, and IU; (2) SmartMeter™ benefits; (3) postage increases; (4) bill inserter maintenance costs; (5) consumables savings; (6) postage savings; (7) ten additional credit operations full-time employees; and (8) kiosk maintenance amount to $104.5 million.

131. PG&E's request is unopposed for authorization to close its Service Disconnection Memorandum Account, and recover recorded costs through annual electric and gas rate true-up processes.

132. PG&E seeks funding to process the increased volume of energy usage data exceptions resulting from hourly interval energy usage data available through SmartMeter™ technology. There is no need to provide billing-quality data for customers to make use of information on their "My Account" website, however, and a reduction of $12 million is warranted for residential customers not currently on an interval billing rate.

133. In order to promote(i) more timely customer uncollectibles management; and (ii) increased bill payment and credit flexibility to assist customers experiencing difficulty in paying their energy bills, PG&E proposes that the uncollectibles factor be based on a rolling five-year average adjusted annually.

134. TURN's alternative proposal provides advantages similar to PG&E's proposal, while incorporating a more appropriate 10-year rolling average time period. A 10-year average offers a more reasonable time horizon that better reflects normalized test year conditions.

135. PG&E's forecast of $3.2 million is reasonable to fund field retrieval and telephony-based metering for large commercial, industrial and agricultural customers and to fund data retrieval associated with load research activities. The

forecast reflects the transition from the meter reading balancing account to GRC-funded revenue requirements.

136. PG&E forecasts $74.7 million in 2014 meter expenses and related capital expenditures of $117.0 million for 2012, $128.0 million for 2013, and $128.2 million for 2014 to provide safe and efficient responses to meter-related customer service requests and compliance work.

137. PG&E's meter reading expense forecast is based on the number of customers forecast to participate in the Opt-Out Program in 2014 multiplied by the forecast unit cost per premise to read the meters. It is reasonable to reduce PG&E's forecast by $24 million based on TURN's unit cost and customer estimates.

138. Use of a two-way balancing account is the most effective way to address and resolve the uncertainty regarding the outcome of the Opt-Out proceeding.

139. PG&E reasonably estimated meter maintenance expenses reflecting the work load experienced by FMO and evaluated current and forecasted conditions for their effect on costs.

140. PG&E's R-Test program is a proactive way to ensure its meters continue to perform at 99% or greater accuracy, thereby allowing PG&E to meet the Commission-approved tariff standard for billing accuracy, which depends in turn upon meter accuracy. Ad hoc testing of meters does not replace a proactive approach.

141. PG&E forecasts $42.6 million for electric meter replacement and customer growth; installation labor; corrective maintenance requiring meter exchange or replacement; meter removals and retirements; Load Research Program and SmartMeter™ network equipment.

142. PG&E's forecast reasonably reflects new activities for 2014 including to purchase meters for PG&E's Scheduled Meter Change (SMC) Program, SmartMeter™ gas module replacement, temperature compensating indexes, SMC-related regulator replacements and turbine and rotary meter replacements.

143. PG&E's incremental expense forecast for MWC IV (Provide Account Services) of $24.1 million includes: (a) providing customer service through Energy Solutions & Services customer account managers, and (b) providing Community Choice Aggregation (CCA) customer support. Limited funding is justified for increases of 84 staff positions from 2011 to 2014. An increment of 84 positions is the same per-year rate of change (i.e., 28 positions per year) by which staffing declined from 176 positions (in 2007) to 64 positions (in 2011).

144. The claimed benefits from the Customer Insight and Strategy program are not sufficient to prioritize it for additional ratepayer funding for this GRC.

145. PG&E forecasts $1.5 million for customer retention activities to provide a full and accurate analysis of the financial impact to remaining customers if a publicly-owned utility (POU) takes over or expands service in PG&E's service area.

146. PG&E forecasts $8.2 million for the Customer Care IT Program to adapt to the evolving technology landscape, improve customer service, and capture efficiencies.

147. PG&E forecasts $722 million for Energy Supply expenses for 2014 and capital expenditures of $635.593 million (an increase of 18% over 2011 levels) based on a portfolio of resources including nuclear, hydroelectric, fossil, and solar generation, as well as contracted energy resources to supply customer generation needs.

148. PG&E forecasts $191.14 million for Hydro expenses for Test Year 2014, driven by: (a) new programs for Hydro conveyances, penstocks, and dams to evaluate and mitigate safety risks; (b) new security requirements and records management; (c) dam repairs, support for ongoing land conservation efforts, and requirements in recently issued FERC licenses; and (d) price inflation.

149. DRA is critical of PG&E's reallocating funding for projects approved in previous GRCs to fund other work, and believes that proposed 2014 increases for reallocated work and deferred maintenance should be the responsibility of shareholders, and not customers.

150. DRA's and TURN's reliance on past spending patterns may not adequately capture funding needs for new or changing requirements, particularly in view of safety and reliability requirements.

151. It is reasonable to reduce PG&E's forecast for MWC KG and KJ by $2 million, as proposed by TURN. The reduction is warranted in view of the lack of detail justifying PG&E's requested increase.

152. PG&E's increased deployment of helicopters will improve visibility of rivers to warn recreationists in advance of flow changes, improve surveillance, and enable PG&E to perform construction and maintenance of facilities in the remote Shasta and DeSabla areas.

153. PG&E forecasts $14.6 million for 2014 for routine facility maintenance for hydro structures, roadways and infrastructure.

154. It is reasonable to reduce PG&E's hydro forecast for MWC KI to remove two blanket projects amounting to $1.297 million as proposed by TURN. These projects cover work that has not been scoped or prioritized, and is in addition to increases for division-level forecasts for specific projects.

155. DRA's proposed disallowances would result in insufficient funding to cover the increased scope of hydro programs, including non-routine painting, paving, and roof repair projects to extend asset life and avoid future infrastructure maintenance and replacements.

156. PG&E forecasts $3.4 million for multiple IT projects planned for 2014, developed by estimating the expense portion associated with multiple IT improvement projects.

157. In the 2011 GRC, PG&E requested funding to build an IT records management environment around a tool called Documentum® as the foundation for an enterprise-wide data archival and records management program. PG&E is now building the Documentum® tool, and forecasts data conversion from various documents to Documentum®.

158. PG&E forecasts Hydro capital expenditures of $293 million for 2012, $261 million for 2013, and $345 million for 2014 due to: (a) upgrades and modifications to dams, penstocks and waterways due to changing FERC and Division of Safety of Dams guidelines, as well as PG&E's assessments; and (b) turbine and generator projects to ensure safety and reliability.

159. DRA, TURN, and EPUC all propose reductions to PG&E's 2014 hydro capital forecast.

160. DRA's proposal does not adequately account for the effects on reliability and safety of deferring, reprioritizing, and/or delaying projects merely because they involve multi-year spending plans.

161. TURN's proposed reduction of PG&E's hydro capital cost forecast based on exclusion of low-priority projects is reasonable. TURN's proposed reductions apply to one-half the costs of PG&E's low scoring blanket projects, one-half the

costs of individual projects with scores of 11-20, and all costs of individual projects that scored 0-10.

162. It is reasonable to reduce PG&E's capital budget by $27.023 million capital reduction ($12.5 million weighted average), to exclude funding for projects identified as low priority, as proposed by TURN. Adopting this reduction does not preclude PG&E from exercising discretion to continue to reprioritize spending within available funding as changing conditions warrant.

163. EPUC's proposed level of hydro capital spending reductions for MWCs 2M, 2N, and 2P goes too far in potentially impacting PG&E's ability to provide safe and reliable service.

164. PG&E's proposed IT projects including the Records Information Management Documentum® and Asset Management/Condition Based Maintenance have been reasonably justified.

165. TURN proposes reductions to PG&E's capital budgets for work related to: (1) Crane Valley Dam rebuild, (2) Lake Nora Walkway, and (3) Helms Cooling Water Control Replacement projects. PG&E's planning, management, and spending on each of these projects were reasonable, however, based on information that PG&E knew or could reasonably have learned at the time.

166. PG&E forecasts $45.176 million for MWC 11 which includes investments for FERC licenses for hydro facilities upon expiration of previous licenses; license amendments to reflect changes in license-related projects/facilities and operations; and to install/construct equipment or facilities to comply with license conditions. Capital spending on hydro projects is tied to FERC relicensing, with the costs going from construction into plant in service once relicensing occurs.

167. TURN's proposed reductions in MWC 11 reflect more accurate in-service dates for various projects for which FERC relicensing has been delayed. Because of uncertainty regarding the duration and timing of issuance of FERC licenses, it is difficult for PG&E to forecast when FERC will issue new licenses for hydroelectric projects or to forecast the related costs.

168. PG&E's proposal to create a FERC Hydro Licensing and License Implementation two-way balancing account would include all FERC License Renewal and major License Amendment work, plus implementation costs to comply with pending new license conditions. A two-way balancing account is administratively simpler than TURN's proposal, and over time, will accomplish a similar result, making both ratepayers and shareholders whole for forecasting variances relating to license renewal timing.

169. PG&E forecasts $415.5 million for 2014 Nuclear Operations expenses for the DCPP, consisting of two nuclear PWR units and steam electric turbine generators, feed water and cooling water systems, and related facilities.

170. DRA's recommended reduction of $92.3 million to PG&E's DCPP forecast is based on a three-year historic average (2010-2012).

171. Three issues are in dispute regarding the dual refueling outages at DCPP in 2014: (a) the reasonableness of PG&E's forecast cost for the outages; (b) ratemaking treatment for cost recovery of the second outage; and (c) whether duplicate costs exist for forecast Steam Generator (SG) inspections.

172. PG&E expects to incur $97.5 million in 2014 covering the first and second refueling outages at DCPP, but proposes to normalize the cost of the second outage in 2014 by including one third of the total costs in 2014 and in the 2015-2016 attrition years, equal to $18.7 million annually.

173. PG&E's proposed treatment of the DCPP refueling outages reduces 2014 forecast expense by $37.4 million and credits rate base with prepayment of $18.7 million for the second outage occurring in 2014. PG&E includes this $37.4 million in its proposal to amortize the second refueling outage over three years.

174. PG&E has reasonably forecast the cost of the two DCPP refueling outages scheduled for 2014, except for the reductions (a) to normalize one-time steam generator inspection costs over the three-year GRC cycle and (b) to adjust for the 6% improper double-escalation rate applied to the steam generator costs, reducing PG&E's forecast by $0.5 million, for a net amount of $5 million. To normalize the $5 million over three years result in $1.667 million per year (instead of PG&E's $5.5 million forecast).

175. PG&E's proposal to average the refueling outage costs over the three-year GRC cycle, except for aforementioned adjustments to normalize steam generator costs and adjust for the 6% improper escalation rate, is otherwise reasonable by providing uniform treatment over the GRC cycle and avoiding a larger increase in 2014 followed by a decrease in 2015.

176. DRA's historic averaging method does not account for the costs of a second refueling outage, thereby understating the 2014 forecast by $10.9 million, excluding inflation.

177. TURN's proposed approach for DCPP refueling outage costs would (a) set a single cost amount per refueling outage, (b) place one outage into base rates, and (c) allow PG&E to collect the cost for an additional outage in any year where two outages actually occur. TURN omits the impact of additional inspections required for 2014 outages which increase outage costs.

178. PG&E's 2014 forecast for MWC BP of $14.858 million reflects its agreement to include only 50% of the NEI fees.

179. PG&E's 2014 forecast for MWC BQ of $46.353 million includes the: Site Services Department, Security Operations Group, Emergency Planning Group, Fire Protection Group, Industrial Safety Department, Access Control Group and Procedure Services Section.

180. By relying on average costs between 2007-2011 as a basis to forecast MWC BQ, DRA omits proper recognition of test year requirements and of the accounting change implemented in 2011 relating to security costs.

181. PG&E forecasts $107.34 million for DCPP operating expenses in MWC BR which includes: Operations Services, Chemistry Department, and Radiation Protection, and includes labor costs for licensed and non-licensed nuclear operators and support staff.

182. It is reasonable to reduce PG&E's forecast for DCPP Operating Expense by $9.437 million based on the facts that: (1) a large portion of new staff can be covered by 2011 embedded costs of excess staffing, (2) fewer than 58 new hires are needed to "shadow" retiring workers because senior staff need less training, and (3) new staff reduce the embedded cost of temporary outage workers.

183. DRA's forecast of DCPP Operating Expense based on a historic average, does not account for changed staffing requirements expected for 2014, and does not explain why 2012 staffing increases should be disregarded or why PG&E's plans for 2013 and 2014 are unjustified.

184. PG&E reasonably forecasts $184.18 million for preventive and corrective maintenance and surveillance testing of DCPP's mechanical and electrical equipment, instrumentation and controls. DRA's proposed reductions do not properly consider the costs of the second refueling outage, the change in

accounting for security and facility costs; and excludes labor escalation. DRA's proposal to amortize three projects over three years is not appropriate here since the projects are ongoing and the amounts are relatively small.

185. PG&E's 2014 forecast is $23.536 million for Personnel Performance Enhancement expenses.

186. PG&E's forecast of $70.238 million is reasonable to cover DCPP Engineering Department costs in MWC BV consisting of: Design, System, Component and Reactor Engineering; In-Service Testing and Inspection; Reliability Engineering (including predictive and preventive maintenance); and Fire Protection Engineering.

187. PG&E's 2014 forecast for Nuclear Operations IT project expenses in MWC JV is reasonable.

188. It is reasonable to reduce PG&E's forecast of NRC regulatory and inspection fees by $1.326 million as proposed by TURN, because PG&E's trend line analysis is unduly biased by escalation during 2007-2010 that has not continued in subsequent years.

189. There is no evidentiary basis to adopt the A4NR proposal to disallow 50% of PG&E's funding request for the LTSP as "advocacy" expenditures. After its testimony was stricken, A4NR withdrew this recommendation for lack of evidentiary support.

190. It is reasonable to adopt the A4NR proposal to remove $4.84 million in LTSP costs from this GRC and transfer the costs to the balancing account adopted in D.12-09-008 as a ratemaking mechanism for seismic studies.

191. It is reasonable to adopt the A4NR proposal to place conditions on approval of PG&E's cost recovery of $26.1 million to construct the remaining five pads at the ISFSI in 2014. Since 2015 and 2016 revenue increases are limited

to the attrition mechanism adopted in Section 12 of this decision, the A4NR proposal is moot as it relates to PG&E's proposed $19.6 million to transfer spent fuel to dry cask storage in 2015 and 2016.

192. It is reasonable to exclude the $3.9 million for the capitalized Transformer Supercooler Replacement from the 2014 revenue requirement because PG&E already recovered the cost of this project through the expense component of the 2011 revenue requirements (even though PG&E did not account for the transaction as maintenance expense, as originally contemplated).

193. PG&E's forecast 2014 expense includes no expense for maintenance of the Transformer Supercooler. Under PG&E's proposal, however, ratepayers would fund a capital replacement that substituted for maintenance that ratepayers previously funded but which never occurred.

194. It is reasonable to reduce PG&E's capital forecast for 2014 by $3.28 million for repaving the Diablo Canyon Access Road based on similar considerations as apply to disposition of the Transformer Supercooler.

195. In connection with the Long Term Seismic Program to study and update information on seismic hazards relevant to the safe operation of Diablo Canyon Power Plant, PG&E was to submit a draft report containing the most recent results of its seismic surveys to the Nuclear Regulatory Commission by mid-summer 2014. Depending on the results of the studies, the effects of any long-term seismic vulnerabilities may need to be addressed.

196. The Nuclear Regulatory Commission has issued, or will be issuing shortly, new safety regulations in rulemakings related to its Fukushima review, cybersecurity, Emergency Plan modifications, and a new National Fire Protection standard. Given the uncertainties involved, it is reasonable to establish a two-way balancing account for costs for NRC rulemakings for the Fukushima

Daiichi Nuclear Station costs of $11.500 million, Cybersecurity of $1.608 million and Emergency Planning of $1.452 million.

197. PG&E's 2014 expense forecast of $14.591 million is reasonable for planning and performing routine operations at PG&E's fossil facilities, including engineering and clerical support. PG&E's adjustment of $267,000 for overtime is an appropriate resolution of disputes over funding for two new technicians at Humboldt.

198. PG&E's forecast of $31.9 million is reasonable for maintenance at Gateway, Colusa and Humboldt, including labor to maintain the facilities, the Long-Term Service Agreements at Colusa and Gateway, materials and contracts, and other maintenance and engineering services.

199. TURN's proposal that PG&E defer maintenance by changing the running hours on the Humboldt units could adversely affect reliability in the North Coast region by having multiple units out for maintenance at the same time.

200. Based upon agreements between the parties, there are no disputed issues concerning PG&E's capital expenditures forecast for the Fossil and Other Generating Operations.

201. PG&E forecasts $50.209 million for MWC CT, which represents the majority of Energy Procurement budget. It is reasonable to reduce PG&E's forecast for MWC CT to exclude the increase of 12 positions, recognizing that funding previously provided in the 2011 GRC should count toward the cost of the 12 positions filled in 2012 and 2013. In all other respects, PG&E's MWC CT forecast for 2014 is reasonable.

202. PG&E forecasts $33.9 million in capital expenditures for IT costs associated with development of in-house software solutions, as well as the purchase of external software vendor solutions, to meet business needs and

compliance requirements within Energy Procurement. PG&E's 2013 and 2014 forecast should be reduced by 14% to reflect use of the Concept Cost Estimating Tool.

203. It is reasonable to adopt the proposed method presented in the Joint Exhibit (Exhibit 330), jointly sponsored by PG&E, TURN, and MEA, for crediting the Department of Energy (DOE) litigation proceeds to generation rates and nuclear decommissioning rates as presented in the joint exhibit.

204. PG&E's Shared Services forecast includes the Safety Department, Transportation Services, Supply Chain, Real Estate, Environmental Programs, as well as IT.

205. PG&E's forecast for the Safety Department's 2014 expense of $15.587 million is reasonable and includes funding to hire 21 additional safety professionals to support field operations, and implement IT solutions to improve safety work management.

206. PG&E did not separately delineate safety risk mitigation measures by employee category, but it is reasonable to evaluate PG&E's overall safety professional funding based on the same metric used for identifying an industry benchmark. Consideration of safety personnel relative to total workforce is an industry best practice.

207. DRA did not provide substantive objections to PG&E's new IT programs, but proposed reductions based on past spending patterns. PG&E's spending pattern in prior years, however, does not justify denying otherwise defensible test year increases.

208. PG&E forecast of $42.725 million for fuel expenses for its vehicle fleet is reasonable, derived by assessing historic fuel values relative to current and projected requirements.

209. DRA's fuel expense forecast assumes a unit price per gallon of fuel that does not account for price fluctuations over time, but is based on one week of fuel prices. DRA also assumes that the replacement vehicles will be 100% electric vehicles, although PG&E plans to deploy plug-in hybrid gasoline and electric vehicles.

210. PG&E's 2014 Transportation Services capital forecast of $139.3 million is comprised of vehicle purchases, electric vehicle charging infrastructure, IT initiatives, and tools and equipment.

211. PG&E's 2012-2014 capital forecasts of Fleet/Auto Equipment capital expenditures for MWC 04 reasonably reflects costs due to regulatory compliance, replacing vehicles at the end of their lifecycle, and buying additional vehicles. DRA's proposed reductions are based on erroneous assumptions with respect to: (1) the in-service date for new vehicles; (2) type of vehicles deployed; and (3) type of vehicles replaced.

212. PG&E's forecast of $132.7 million for materials and supplies (M&S) inventory is reasonable to support maintenance programs and Nuclear Regulatory Commission and Institute of Nuclear Power Operators mandated systems and regulations. DRA's proposed reduction to the M&S inventory forecast is based on a linear regression methodology that fails to account for changed conditions regarding inventory needs that are not reflected in regression data.

213. The key driver of PG&E's expense forecast for Supply Chain Sourcing Operations of $13.077 million is due to an upgrade to the primary purchasing system: the SAP Supplier Relationship Management System.

214. PG&E's forecast of $9.732 million in MWC JL for its Diversity and Sustainability Programs is reasonable to improve administration of the

Commission's diversity certification database. In proposing a disallowance based on historic averages, DRA did not account for all applicable costs expected during the test year.

215. PG&E's forecast of $32.59 million for Corporate Real Estate expense is an increase of 172% over 2011 due to improvements to aging buildings and yards, maintaining reliability, providing office space, completing seismic safety upgrades, improving building accessibility, and disposing of surplus real estate.

216. For the most part, PG&E's construction forecasts are based on reasonably supported unit cost assumptions and there is insufficient basis to rely on TURN's alternative unit cost construction forecasts.

217. As an approximation of the effect of applying local multipliers to all of PG&E's unit cost construction forecasts, a 5% reduction to PG&E's capital cost forecast for Base Building and Seismic Safety projects is reasonable.

218. Applying overhead cost adders based on recorded data will reasonably compensate PG&E for management and engineering costs. By adjusting forecasted adders based on recorded data, the total overhead adder is 16.5%, or 1.7% lower than PG&E's forecasted 18.2%.

219. PG&E's proposed 2014 work scope for seismic safety and ADA compliance is reasonable. PG&E's seismic safety forecast addresses important safety risks, and implements the California Seismic Safety Commission mandate for a program to manage earthquake risks with a dedicated staff and budget.

220. PG&E has generally justified the benefits of funding most of the programs proposed for MWC 23, but has not justified funding the consolidations of the Canyon Dam and Quincy Service Centers to a new location in Greenville ($55,000 expense and $6.2 million capital) and the Clearlake and Lakeport service centers to a central location ($92,000 expense; $6.3 million capital).

221. PG&E has justified funding for a new 12kV power feed from the Cordelia Substation to the Fairfield Data Center. If the Data Center were to experience a catastrophic failure, critical information would be unavailable for at least 24 hours, and PG&E's Customer Call Center call routing systems would be inoperable.

222. It is reasonable to adopt a forecast that reflects a somewhat longer time frame than what PG&E forecasts for implementing various programs forecast under MWC 23. PG&E can extend implementation over the three-year GRC cycle, consistent with its obligation to provide safe and reliable service.

223. PG&E's forecast of $3.34 million in MWC JE associated with Land Services including funding to establish a Land Stewardship Management Program is reasonable.

224. PG&E's forecast for Environmental Program capital of $11.526 million includes costs for development of Habitat Conservation Plans, underground storage tank removal, IT initiatives, and tools and equipment.

225. Leaking tanks create environmental and safety hazards by contaminating soil and groundwater. The cost of remediating soil and groundwater is significantly higher than the cost of removing the tanks as they near the end of their useful life and are still operational. PG&E's program to remove the tanks reduces the potential for leakage.

226. PG&E projects 2014 expenses of $261.6 million in MWC JV for enterprise-wide IT projects and programs. Key cost drivers are escalation for maintenance contracts and licensing plus increased headcount to support increases in IT devices, systems, and applications. Key drivers of PG&E's capital forecast include adding three new asset classes to the Lifecycle program and

implementing three Technology Reliability projects and two Continuous Improvement projects.

227. PG&E's forecast of $240.9 million for Baseline operations for ongoing maintenance of IT systems and infrastructure is reasonable. DRA's proposed reduction of $19.7 million to PG&E's forecast of Baseline expenses, based on recorded Baseline expenses from 2008 to 2012, does not consider the factors driving the increases in the Baseline expense forecast amounts for ongoing maintenance of IT systems and infrastructure.

228. PG&E's forecast of IT Lifecycle capital expenses of $102.9 million in 2014 is reasonable. Use of a five-year historic average does not adequately reflect changed test year conditions that require a greater scope of activity and spending for IT.

229. PG&E's forecast of $33.9 million in 2014 capital spending, and $3.1 million in 2014 expenses for Disaster Recovery is reasonable to reduce risks relating to IT and cybersecurity. TURN's proposal to reduce the forecast by one-half would reduce benefits and would not serve ratepayers' best interests.

230. PG&E's 2014 forecast of capital expenditures and expenses for the Telecommunications Network Enhancement project should be reduced in view of the projected network bandwidth needs and applying a limit of one mobile device per work crew. Accordingly, it is reasonable to reduce PG&E's Telecommunications Network Enhancement, 2014 expense by $525,000 and to reduce capital expenditures by $5.9 million.

231. PG&E forecasts capital costs of $16.5 million in 2014, and $4.1 million in 2014 expenses for its Records Management Archival project are reasonable. PG&E's records management needs have increased and funding the additional functionality forecasted in this rate case is warranted.

232. PG&E's forecasts for capital costs of $5.3 million in 2013, $6.9 million in 2014 and $1.0 million in 2014 expenses for its Service Management project are reasonable. PG&E's IT systems are more complex today, and the Service Management improvement initiative will help to ensure the reliability and efficiency of its IT environment.

233. PG&E uses the Concept Cost Estimating Tool to generate initial forecasts of software application development projects early in the project lifecycle, and has used this tool since 2008 to generate initial cost estimates for software application development projects.

234. DRA calculated that PG&E only spent 86% of its 2011 GRC funding for IT projects as compared to forecasted amounts derived using PG&E's Concept Cost Estimating Tool. Therefore, DRA believes that it is reasonable to impute a similar potential forecast variance for IT projects in the 2014 GRC that are forecasted using the Concept Cost Estimating Tool. DRA's forecast for these IT projects thus results in a proposed reduction of 14% (i.e., 100%-86% = 14%).

235. Based on its recalculation, PG&E claims 99% accuracy of its forecasts generated by the Concept Cost Estimating Tool.

236. Although DRA did not include 2013 data in its calculation of the accuracy of the Concept Cost Estimating Tool, DRA did make comparison of three years of forecasted and recorded capital costs, using 2010 to 2012 costs combined with forecasted and recorded expense from 2010 to 2011. By comparing recorded costs and forecasts for the most recent three-year period available at the time, DRA's calculation of an 86% forecast variance was not unfairly inflated.

237. In calculating a claimed 99% accuracy rate in its use of the Concept Cost Estimating Tool, PG&E limits its comparison only to projects that are operational

and in development and excludes projects that were cancelled or deferred. PG&E received ratepayer funding for the cancelled and deferred projects, however, as well as for those that were successfully completed. As the basis for calculating 99% accuracy, PG&E includes the final year of a GRC cycle twice (i.e., once for 2010 and again for 2013), and based on comparing a 2013 forecast to a later 2013 budget, rather than comparing recorded to forecast 2013 data.

238. In calculating the accuracy of the Concept Cost Estimating Tool, DRA did not remove individual projects that were deferred or cancelled, but DRA likewise did not adjust for projects with changes in scope or duration. DRA's calculation was intended to capture forecast variances not only in projects that reach completion, but to identify forecast variance from all sources, including projects that get cancelled or postponed.

239. PG&E forecasts $793.165 million for HR compensation and benefits.

240. PG&E includes aspects of cultural sensitivity training in its diversity and inclusion training programs, and anticipates there would be significant cost associated with a training program as described by Greenlining.

241. PG&E and DRA jointly administered a study of total employee compensation in this GRC, selecting Mercer (US) Inc., an independent consulting firm, to perform the study. Mercer concluded that PG&E's total employee compensation was competitive with the market based on PG&E's aggregate total employee compensation being with 10% of the market median.

242. DRA's global recommendation to reduce labor costs by $123.67 million is intended to bring PG&E's total compensation package to within a variance of 5% above the market median based on the premise that PG&E's total compensation is 9.9% above the market median.

243. Mercer, the independent consultant utilized by PG&E and DRA to produce a Total Employee Compensation Study, re-ran the Total Compensation Study using employee benefit plan designs PG&E proposed for its 2014 GRC that were not included in the initial study. After accounting for the plan design changes already implemented, PG&E's total employee compensation was calculated as being only 5.2% above the market median.

244. PG&E forecasts $130.2 million to fund its STIP and $107,000 for STIP for the Corporation in 2014. The STIP covers PG&E management employees, professionals, and non-represented employees, and represented employees where agreed to through collective bargaining.

245. Offering employee compensation in the form of incentive payments is useful for recruiting and retaining skilled professionals and improving work performance. Ratepayers derive benefits from various elements of the STIP and should bear a reasonable level of costs commensurate with benefits. PG&E shareholders benefit from STIP as much as or more than do ratepayers.

246. Adopting a sharing of STIP costs between ratepayers and shareholders is consistent with prior Commission decisions where ratepayer funding of employee incentive compensation was authorized but where ratepayers did not bear the entire burden of such costs.

247. Two elements of STIP compensation essentially benefit shareholders, but without a clear demonstrable benefit to ratepayers. These are: (a) the measure of Earnings from Operations (EFO) and (b) the Customer Satisfaction metric.

248. Ratepayer expense funding of $89 million of the STIP program for test year 2014 incorporates exclusion of the EFO and Customer Satisfaction metrics, as proposed by TURN, and incorporates a 10% reduction to provide sharing of cost responsibility between ratepayers and shareholders.

249. PG&E's forecast of $8.734 million for the R&R program is reasonable and is designed to encourage employees to work safely, go above and beyond to achieve results, and encourage innovation.

250. PG&E's forecasted average escalation rate of 2.79% is reasonable. The CPI measures changes in consumer prices and is not the best proxy for a wage escalation index.

251. PG&E's proposed funding of $385.1 million for its medical programs less $30.7 million in estimated employee health care contributions is reasonable.

252. PG&E and its unions negotiated a new plan to reduce health care costs through more efficient plan design with incentives for employees to take a more active role in their health management. PG&E's proposed funding increases are consistent with terms of the new health plan.

253. PG&E's forecast of 5.4% health cost escalation rate for 2014 is based on the trend rate of 5.4% provided by Towers Watson, and based on PG&E's experience, which is lower than trend findings from recent California and national surveys on health care costs.

254. Consistent with Commission treatment of similar costs in the Sempra proceeding, it is reasonable to allow only 50% of PG&E's $1.3 million expense for employee service awards.

255. Consistent with the treatment of pension costs in the Sempra proceeding, it is reasonable to allow only 50% of PG&E's forecast of in 2014 for non-qualified pensions and administrative costs is reasonable, resulting in a $1.63 million reduction. The 50% funding applies to PG&E's pension cost forecast of $3.26 million, which is net of $225,000 administrative costs for all employee pension plans which is allowed in full. The 50% sharing reflects that the pension plan benefits utility's retirees.

256. PG&E's forecast of $41.6 million for workers' compensation benefits and related costs for 2014 is reasonable.

257. PG&E's forecast of $13.3 million for its Workforce Management Program costs in 2014 is reasonable.

258. PG&E's forecast of $45.126 million of Finance Department costs is reasonable, which includes raising capital, communicating with investors, planning and managing budgets, preparing financial statements and tax filings, and managing payment services for employees and vendors.

259. PG&E forecasts $19.18 million for 2014 for its Risk and Audit Department, which oversees risk management, internal audit, compliance, ethics, and corporate security functions. The forecast is reasonable except for a reduction to remove $123,000, so that ratepayers do not fund labor costs for both a retiring director plus his/her replacement for test year 2014.

260. PG&E forecasts $104.5 million in insurance costs for 2014. Ratepayer funding of insurance premiums offers a reasonable way to limit risks of large, unforeseeable loss of utility property due to natural catastrophes.

261. The record does not contain a reasonable identification of a specific portion of insurance premiums as being expressly attributable to the results of the San Bruno natural gas pipeline accident.

262. It is reasonable to reduce the D&O insurance forecast by 50%, resulting in a $1.423 million reduction consistent with past Commission policy of equal sharing of cost responsibility for D&O insurance.

263. PG&E forecasts $63.5 million for the HR organization in 2014. HR functions to attract, retain, and support a highly-qualified and diverse workforce. It is reasonable to reduce the forecast by $4.0 million consisting of: (1) a $1.9 million reduction across FERC Accounts 920 and 921 to keep staffing levels

for PG&E Academy at 2012 levels; and (2) a $2.1 million reduction in FERC Account 923 for Technical Training maintenance based on 2012 recorded data.

264. It is reasonable to reduce PG&E's 2014 forecast for Talent Management to exclude $1.3 million of the requested increase.

265. PG&E forecasts $22.467 million in Regulatory Relations department costs for 2014.

266. It is reasonable to reduce PG&E's forecast for Account 920 (A&G Salaries) for the Regulation and Rates Department by $900,000 to exclude funding for nine additional staff. While more staff would enable processing of increased regulatory workload faster, any additional benefits in terms of regulatory workload processing do not justify burdening ratepayers with paying for more regulatory staff overhead.

267. It is reasonable to exclude the entire $133,624 related to PG&E's costs for the CCEEB activities.

268. Given the fact that FERC and ISO relations relate only to transmission and generation, and not distribution, it is reasonable that FERC and ISO Relations Department expense be directly assigned to transmission and generation at 50% each, with none allocated to distribution.

269. It is reasonable to exclude from the revenue requirement the entire $61,000 paid by PG&E to the California Taxpayers Association because that organization is inherently political.

270. It is reasonable to exclude $199,999 associated with Clothing and Other PG&E Gear from the 2014 revenue requirement because these A&G expenses are for promotional and image building purposes.

271. TURN and MEA raised issues regarding the unbundling of A&G expenses to Electric Distribution, Gas Distribution, Generation, and other UCC.

MEA, TURN and PG&E jointly sponsor a partial settlement that resolves this issue for purposes of the GRC, proposing a method for allocating a portion of A&G expenses from Distribution to Customer Program revenues.

272. Although EPUC opposed the joint settlement of MEA, TURN, and PG&E, EPUC did not present any arguments or evidence justifying denial of the settlement. Since the settlement does not address factors used to allocate Customer Program revenue requirements to customer classes, parties will be free to raise such issues in PG&E's GRC Phase 2.

273. PG&E Corporation operates an Employee Stock Ownership Plan (ESOP), which is a tax advantaged way of allowing employees to own PG&E shares of stock on a group basis.

274. Dividends received within the ESOP are automatically reinvested in PG&E Corporation stock, and give rise to a tax deduction. Dividends paid by a corporation to an ESOP are a tax deduction for the dividend payer.

275. PG&E's ratemaking treatment of income taxes relating to the ESOP deduction is reasonable.

276. The ESOP deduction arises when the Board of Directors of PG&E Corporation exercises discretion to distribute retained earnings by disbursing a stock dividend.

277. As previously determined by the Commission, when deductions are not part of utility cost of service but derive from shareholder funds, the deductions are the property of shareholders and not ratepayers.

278. The Commission has consistently rejected rate recovery of entertainment, political, and social expenses of utilities because such expenses are an unfair economic burden on ratepayers. It is reasonable to exclude $359,231 in meals-related expenditures from PG&E's forecast consistent with this policy.

279. No adjustment to revenue requirements is necessary for the effects of yet-to-be enacted changes regarding Bonus Depreciation. PG&E's treatment of bonus depreciation is consistent with Commission policy as reflected in the Tax Act Memorandum Account (TAMA) per Resolution L-411A.

280. PG&E retained the firm of Gannet Fleming, to produce a Depreciation Study to develop the parameters (i.e., average service life, curve type, and net salvage rates) to calculate test year 2014 depreciation expense. PG&E relied on historical plant records, plant maintenance practices, and expected future events that may affect estimates.

281. PG&E's forecast assumptions are reasonable relating to Depreciation Expense and related parameters (i.e., negative salvage and remaining life rates) for generation assets for which no party raised objections.

282. PG&E forecasts separate percentage rates of removal costs net of salvage for each asset account. Because removal costs exceed salvage value for most asset accounts, PG&E's forecasted net salvage rate is negative in most instances.

283. DRA does not offer a detailed technical critique of net negative salvage rates, but opposes approval of PG&E's forecasted negative salvage amounts because the increases would contribute to a sudden and considerable retail rate impact. DRA recommends a cap of 25% to increases in negative net salvage for 13 distribution accounts.

284. Deferring the increases in negative net salvage rates above the 25% cap, as proposed by DRA, will mitigate the impact on current ratepayers of escalating removal costs without unduly conflicting with intergenerational ratepayer equity.

285. TURN proposed different net salvage percentages for 10 of PG&E's mass property accounts, focusing on large accounts for which changed depreciation parameters would have the greatest impact.

286. Setting a ratemaking provision for negative salvage and ASL parameters is not a precise science, and experts can differ in applying judgment in estimating these parameters.

287. Although PG&E's estimates of negative salvage are generally based on a defensible analysis of cost trends, the growing cost burden on ratepayers associated with such trends is a valid cause of concern. Over a 30-year remaining plant life, PG&E's current forecast assumptions of negative salvage imply an annual growth rate of 9.45%.

288. The principle of gradualism applies where there is a recognized need to revise estimated parameters, but where the change is allowed to occur incrementally over time rather than all at once. Given the magnitude of increases at issue in this GRC, adopting PG&E's negative salvage rates would pose an unacceptably abrupt impact on current ratepayers. Lower estimates than PG&E requests for 2014 test year purposes are warranted based on the principle of gradualism.

289. Adopting reduced estimates for current test year purposes essentially increases the burden on future ratepayers to make up deferred costs over time. The goal is therefore to balance the equities applied to ratepayers over time, considering past, present, and future cumulative cost impacts.

290. PG&E's proposed increases in negative salvage rates reflect limited recognition of gradualism, to the extent that PG&E proposes little or no change in negative salvage rates compared to its proposals in a GRC cycles. In applying the principle of gradualism, however, the more relevant measure is how a

change compares to adopted rates. In this context, the fact that PG&E previously proposed negative salvage rates beyond what was adopted has no bearing on how a proposed increase would impact ratepayer costs.

291. The increases in negative net salvage rates requested by PG&E are not sufficiently gradual to adequately mitigate the impact on current customers.

292. PG&E's ASL estimates for the 11 asset accounts in dispute are reasonable. In view of the magnitude of change involved, adopting the PG&E ASL estimates conforms to the principle of gradualism, as separately applied in connection with negative salvage value estimates.

293. Expert judgment is involved in selecting the appropriate life and curve combination as the basis for ASL estimates for each asset account. While experts can disagree over ASL methodology and results, PG&E's ASL estimates are more defensible than those of TURN.

294. In calculating PG&E's 2014 revenue requirements, "Other Operating Revenue" (OOR), is applied to account for revenues from transactions not directly associated with distribution, generation, or sale of electric energy or natural gas.

295. PG&E and DRA differ in their OOR forecasts by $8.7 million due to differences in forecasts of reimbursed revenues and $1.0 million relating to DRA's reliance on 2012 recorded data. Since reimbursed revenues and expenses are a zero sum game, there is no basis to adjust PG&E's OOR forecast to impute additional reimbursed revenue.

296. It is reasonable to increase PG&E's 2014 forecast for OOR for timber sales revenues by $887,000 based on a five-year average of timber revenues.

297. It is reasonable to increase PG&E's 2014 OOR forecast by $2 million for the effects of additional revenues PG&E will receive from the PCWA under a

new agreement increasing revenues. Although TURN did not address this issue in prepared testimony, TURN did enter into evidence an exhibit indicating that PG&E negotiated the PCWA agreement which increases PG&E's annual revenues.

298. The RO Model used to develop the revenue requirements incorporates test year forecasts for capital additions and depreciation amounts, as adopted in this decision, to derive the adopted 2014 rate base as set forth in Appendix C, Table 10.

299. PG&E's existing AFUDC methodology is based on the approved FERC formula, and no valid basis has been presented to deviate from the FERC formula or to require a different AFUDC rate or methodology based on DRA's arguments.

300. The disallowance adopted in D.11-05-018 offers no support for disallowance of the equity component of the AFUDC rate to finance CWIP. The disallowances in D.11-05-018 involved non-productive investments with no prospective value to ratepayers. By contrast, CWIP does provide value to ratepayers, although that value is realized as a function of the time to complete the CWIP project.

301. Declining to adopt DRA's AFUDC proposal avoids any incremental risk of adversely affecting PG&E's existing short-term borrowing capacity, or increasing borrowing costs.

302. PG&E's nuclear fuel inventory is currently excluded from rate base while nuclear fuel carrying costs are recovered through the Energy Resource Recovery Account (ERRA) proceeding and compensated at the short-term commercial paper interest rate.

303. Based on PG&E's proposal to change the current treatment and include nuclear fuel inventory in rate base, PG&E would earn a full rate of return on nuclear fuel inventory, instead of recovering only short-term commercial paper interest currently set at a 0.4% annual rate.

304. Adopting PG&E's proposed change in nuclear fuel cost recovery would change the status quo, significantly increasing ratepayer costs with no corresponding improvement in service quality.

305. In presenting claims as to potential adverse effects on its short-term borrowing capacity due to opposing parties' positions, PG&E focuses on the effects both of adopting DRA's AFUDC proposals and denying rate base treatment for nuclear fuel. Yet, since the status quo already reflects exclusion of nuclear fuel from rate base, denial of PG&E's nuclear fuel proposal should not have an immediate effect on its short-term borrowing capacity nor require immediate rebalancing of its capital structure.

306. As an accepted financing practice, long term assets should generally be financed with long-term sources of capital over time, and there is some evidence to support the claim that nuclear fuel exhibits characteristics of a long-term asset.

307. Although PG&E has raised valid concerns regarding the long-term viability of limiting recovery of nuclear fuel carrying costs to a short-term interest rate, it would be premature to change the current ratemaking treatment of nuclear fuel at least until all relevant implications for PG&E's adopted cost of capital can be fully considered.

308. Although GRC treatment relating to carrying costs of assets such as nuclear fuel cannot be easily divorced from issues relating to cost of capital, PG&E's cost of capital is reviewed and its authorized rate of return is set in a separate proceeding.

309. TURN's proposed treatment of customer deposits deviates from Commission SP U-16 which excludes interest bearing customer deposits from working cash, and only includes non-interest-bearing customer deposits.

310. For purposes of this proceeding, as an interim measure, it is reasonable to reflect customer deposits in the capital structure as a form of low-cost debt, resulting in an interest rate difference of 5.5% - 0.4%, and thereby yielding a $7 million reduction in revenue requirement. In the next cost of capital proceeding, the impact on PG&E's cost of capital and capital structure as a result of customer deposits as a source of capital can be fully considered and reflected in rates.

311. Including working cash in rate base is a reasonable way to compensate for payment of day-to-day expenses in advance of receipt of offsetting revenues. Working cash requirements are based on the timing of inflows and outflows of cash calculated by a lead-lag study.

312. PG&E has forecasted working cash items using base year data or a four-year average of recorded data unless special circumstances exist.

313. PG&E's forecast of lag days for revenues, federal income tax, and California corporate franchise tax is reasonable as a basis for the working cash allowance.

314. PG&E's revised calculation of a raw goods and services lag of 26.65 days, or a net lag of 25.99 days, is adjusted for transit time of 0.66 days.

315. PG&E's forecast of $1.588 million for deferred debits is reasonable, based on the 12-month 2011 weighted average adjusted for inflation.

316. PG&E's rate base forecast for under accruals relating to the vacation leave deduction is reasonable. Since shareholders absorbed the costs from

accounting changes for vacation accruals, it would be unfair to require shareholders to pay a return to ratepayers for such accruals.

317. PG&E's forecast for company-wide prepayments for software license fees and prepaid insurance, tied to insurance cost growth from 2011 to 2014, is reasonable.

318. PG&E's prepayment forecast for the second DCPP refueling outage is reasonable. DRA's proposed forecast does not correctly calculate the pre-payment over the three-year GRC cycle as it fails to recognize the pre-paid balance remaining in 2015.

319. It is reasonable to reduce to reduce PG&E's rate base forecast by $1.533 million to exclude fuel oil inventory costs for the Humboldt Bay Power Plant since PG&E is adequately compensated for fuel oil inventory carrying costs in the form of short-term interest through the ERRA proceeding.

320. The 2015 and 216 post-test year revenue requirements set forth in Appendix D provide a reasonable basis for an attrition allowance based on separate recognition of (a) expense escalation and (b) capital additions.

321. The expense escalation shown in Appendix D, Tables 3A-3 C, reflects annual wage escalation of 2.79% and health plan escalation of 6.4% for 2015 and 6.3% for 2016.

322. The capital attrition allowance, as derived in Appendix D, Table 2, reflects average capital additions from 2008-2014, and is based on capital escalation factors for 2015 and 2016 in the Update Exhibit (Exh. 375). This methodology yields the rate base adjustments for 2015-16 as shown in Appendix D, Tables 5 through 5C.

323. Because PG&E's forecast of attrition year capital additions have not received detailed scrutiny by other parties, the record does not provide a basis to

make findings as to the overall reasonableness of PG&E's forecast of 2015 and 2016 capital spending.

324. Since PG&E's claims about capital requirements for 2015 and 2016 have not been independently evaluated, there no basis to conclude that use of 2008-2014 capital averages is an unreasonable basis for attrition allowances for 2015-2016 capital additions.

325. Use of the more recent seven-year average of 2008-2014 data (as developed in Appendix D, Table 2, incorporating adopted forecast figures for 2012-2014) offers a more robust basis relative to TURN's use of 2005-2011 data for deriving a 2015-2016 capital attrition allowance.

326. The Settlement Agreement among The National Asian American Association, the Ecumenical Center for Black Church Studies, The Chinese American Institute for Empowerment, The National Hmong American Farmers, The Burmese American Institute for Corporate Responsibility, and Pacific Gas and Electric Company (PG&E), (collectively, the "settling parties") as set forth in Appendix F-1, (Settlement Agreement), including the additional amendments agreed to by the settling parties in comments filed on July 8, 2013, results in a resolution of issues relating to PG&E's proposals for customer outreach and education that is reasonable in light of the whole record, consistent with the law and in the public interest.

327. The joint proposal of PG&E and the Center for Assessible Technology to improve accessibility issues presented in this proceeding (joint proposal), as set forth in Appendix F-4, is a significant advancement over their prior Memoranda of Understanding initiatives, adopted in prior proceedings, in addressing disability issues, and increases the scope of activities to be undertaken and takes steps to institutionalize the improvements within PG&E. The joint proposal is

reasonable in light of the whole record, consistent with the law and in the public interest.

328. The settlement agreement between PG&E and the Small Business Utility Advocates, (the settling parties) as set forth in Appendix F-2, resolves all issues in this proceeding between the settling parties, and is reasonable in light of the whole record, consistent with the law and in the public interest.

329. The resolution of issues in the partial Settlement Agreement, as amended, among PG&E, TURN and MEA set forth at Appendix F-3 is reasonable in light of the record, consistent with the law and is in the public interest.

Conclusions of Law

1. 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.

2. The Commission's duty and obligation under Pub. Util. Code § 451 is to establish just and reasonable rates to enable the utility to provide safe and reliable service, while allowing an opportunity to earn a fair return on the property used and useful in providing utility services.

3. In adopting the revenue requirements as set forth in Appendix C and Appendix D, and consistent with the obligations under Pub. Util. Code § 451 is 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 standard of proof that PG&E must meet is that of a preponderance of evidence. Evidence Code Section 190 defines "proof" as the establishment by evidence of "a requisite degree of belief." To meet the standard of proof, PG&E

must present more evidence that supports the requested result than would support an alternative outcome.

5. The requirement for an annual report describing improvements to PG&E's website has outlived its usefulness. PG&E's request to discontinue the reporting on PG&E's website is unopposed and should be granted.

6. In evaluating whether to approve PG&E's GRC forecasts, the Commission has considered whether PG&E's showing justifies: (1) the need for and reasonableness of the proposed programs, supported to the extent feasible by a cost-benefit analysis; and (2) that the proposed program or project is the most cost-effective alternative available.

7. PG&E's 2014 GRC forecast utilizes 2011 recorded data as a base year, although use of more recent data to determine 2014 forecasts is not prohibited by the Rate Case Plan, and may be considered where useful in developing improved forecasts.

8. In view of the uncertainties involved in forecasting certain categories of costs over the 2014-2016 period, implementation of two-way balancing account treatment is warranted for such costs, as identified and authorized in the applicable ordering paragraphs below.

9. As discussed in the Gas Distribution Section of this decision, the adopted 2014 test year expenses and rate base amounts set forth in Appendix C relating to Gas Distribution are just and reasonable and should be adopted.

10. As discussed in the Electric Distribution Section of this decision, the adopted 2014 test year expenses and 2012, 2013, and 2014 capital expenditures reflected in Appendix C relating to Electric Distribution are just and reasonable and should be adopted.

11. As discussed in the Customer Care Section of this decision, the adopted 2014 test year expenses and rate base amounts reflected in Appendix C relating to Customer Care are just and reasonable and should be adopted.

12. As discussed in the Energy Supply Section of this decision, the adopted 2014 test year expenses and rate base amounts reflected in Appendix C relating to Energy Supply are just and reasonable and should be adopted.

13. As discussed in the Shared Services and IT Section of this decision, the adopted 2014 test year expenses and rate base amounts reflected in Appendix C relating to Shared Services and IT are just and reasonable and should be adopted.

14. As discussed in the Human Resources Section of this decision, the adopted 2014 test year expenses and rate base amounts reflected in Appendix C relating to HR are just and reasonable and should be adopted.

15. As discussed in the Administrative and General Cost Section of this decision, the adopted 2014 test year expenses and rate base amounts reflected in Appendix C relating to Administrative and General costs are just and reasonable and should be adopted.

16. As discussed in the Results of Operations Section of this decision, the adopted 2014 test year expenses and rate base amounts reflected in Appendix C relating to RO issues are just and reasonable and should be adopted.

17. Given the magnitude of increases resulting from PG&E's negative salvage rate forecasts, although costs for negative salvage are generally increasing, adopting PG&E's negative salvage rates would pose an unacceptably abrupt impact on current ratepayers. Accordingly, based on the principle of gradualism, it is reasonable to adopt some degree of increase, but at lower estimates of salvage rates than PG&E requests for 2014 test year purposes.

18. In evaluating whether an increase in depreciation rates reflects gradualism, the appropriate measure is how the change affects customers' retail rates. The fact that PG&E previously proposed higher removal costs than was adopted has no bearing on how PG&E's currently proposed increase would change ratepayers' existing rates.

19. The proposal of DRA to limit increases in negative salvage rates for contested accounts to no more than 25% above existing levels offers a reasonable application of gradualism, and should be adopted.

20. While future ratepayers should not be unfairly burdened with unduly large deferred costs from prior GRC cycles, the correct remedy is not to subject current ratepayers to similar unfair burdens by imposing inordinately large negative salvage cost burdens attributable to deferrals from prior GRC cycles.

21. As discussed in the Rate Base Section of this decision, the adopted 2014 rate base figures and supporting tables reflected in Appendix C are just and reasonable and should be adopted.

22. As discussed in the Attrition Rate Adjustment Section of this decision, the adopted methodology for determining 2015 and 2016 attrition adjustments, as reflected in Appendix D is just and reasonable and should be adopted.

23. A post-test year attrition mechanism is not intended to cover all potential cost changes through 2015 and 2016, but is merely to mitigate economic volatility between test years so that a well-managed utility can provide safe, reliable service while maintaining financial integrity.

24. Adopting a two-part attrition mechanism is a reasonable way to capture distinctions driving attrition increases (a) for expenses versus (b) for capital expenditures.

25. Since PG&E's proposed labor escalation factor is based on wage levels currently provided under existing collective bargaining agreements and developed based on benchmark data, an attrition allowance based on PG&E's proposed factor of 2.79% per year and non-labor escalation factors found in PG&E's update exhibit (Exh. 375 (PG&E-32)) offers a reasonable basis for 2015 and 2016 attrition allowances.

26. In the interests of promoting the incentive for PG&E to contain health plan cost increases through the attrition period, it is reasonable to rely on forecasts offered by DRA for setting attrition allowances for employee health plan costs based on IHS Global Insight's Group Health Insurance index of 6.4% for 2015 and 6.3% for 2016.

27. It is reasonable to include an attrition provision for PG&E to request cost recovery under a Z-factor mechanism based generally on the criteria as previously identified in D.05-03-023, and subject to a $10 million deductible per Z-factor event.

28. Use of an historical average of capital expenditures is consistent with the approach applied in the prior proceedings, and normalizes actual utility spending variations over time. Without conducting full-scale review of 2015 and 2016 capital spending requirements, use of historical averages offers a reasonable approach to setting an attrition allowance.

29. The Joint Motions separately filed to adopt each the Settlements and joint proposals set forth in Appendix F-1 through Appendix F-5 should be granted since each of the respective settlements and joint proposals meet the criteria under Commission Rule 12.1, and the terms set forth therein as specified in the respective appendices should be approved and adopted.

30. In general recognition of the uncertainties regarding the long-term seismic vulnerabilities of Diablo Canyon Power Plant, the Commission retains the discretion to exercise its options as may be deemed necessary to protect ratepayers from unreasonable costs if Diablo Canyon was to no longer be operational.

31. This Commission has legal authority to oversee seismic study activities relating to Diablo Canyon and to condition approval of PG&E's cost recovery of $26. 1 million to construct the remaining five pads at the ISFSI in 2014 upon PG&E's submittal of a plan to expedite the transfer of spent fuel to dry casks while maintaining compliance with NRC cask and pool spent fuel storage requirements.

32. To the extent there are any other outstanding motions or requests that have not been addressed in this decision or elsewhere, those motions and/or requests should be denied.

33. Because it is beyond the scope of this GRC to comprehensively address all cost of capital issues as a result of divergent proposals for nuclear fuel cost recovery, parties should be permitted to raise the issue of whether to include nuclear fuel in rate base in PG&E's next cost of capital proceeding.

34. PG&E's proposed wage escalation factor of 2.79% per year, based on a weighted average of wage increases of 2.75% for union employees and 2.97% for non-union employees, is reasonable for setting 2015 and 2016 attrition rates.

35. DRA's recommended medical cost escalation, based on IHS Global Insight's Group Health Insurance index, yields increases of 6.4% for 2015 and 6.3% for 2016, and is a reasonable basis for setting attrition allowances.

36. PG&E's proposed ARA escalation allowance for adopted 2014 non-labor operating and maintenance and administrative expenses, based on IHS Global Insight data, is reasonable.

37. While test year additions have been scrutinized in detail in this proceeding, PG&E's forecast of attrition year capital additions have not received such scrutiny. Absent a comprehensive scrutiny of 2015 and 2016 forecasts, PG&E's claims about forecasted capital spending requirements for 2015 and 2016 remain unsubstantiated.

38. Given the lack of a comprehensive record concerning 2015 and 2016 spending forecasts, the use of a seven-year average of capital expenditures from 2008-2014 offers a reasonable methodology to derive attrition adjustments for capital spending in 2015 and 2016 as derived in Appendix D.

39. Although the CPI may reasonably measure price inflation faced by consumers, it does not measure price escalation for goods and services procured by an energy utility. The capital escalation factors based on category of plant, as proposed by PG&E in its Update Exhibit (Exh. 375), offers a more suitable basis to escalate expenditures for attrition year purposes.

40. The oral and written rulings of the assigned ALJ that were issued in this proceeding should be confirmed.

41. This proceeding should remain open to consider whether PG&E should be directed to take actions subsequent to the 2014 test year to promote employee and public safety and system reliability, including consideration of the recommendations in the consultant reports prepared by Liberty, Consulting Group, Cycla Corporation, and Overland.

42. PG&E should begin working on developing the data for a base line system wide leak find rate that could form the basis setting performance metrics and

rate levels consistent with best practice. In the next phase of this proceeding, dealing with prospective recommendations in the Safety Consultant Reports relating to PG&E's risk assessment and mitigation practices, further directives should be considered regarding the development of such performance metrics.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company (PG&E) is authorized to collect, through rates and authorized ratemaking accounting mechanisms, over the remainder of this rate case cycle through December 31, 2016 the (i) test year revenue requirement set forth in Appendix C of this decision, less (ii) the amount collected by PG&E base rates since January 1, 2014, 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.

2. 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 1 above, and set forth in Appendix C, and (ii) all accounting procedures, fees, and charges authorized in this decision that are not addressed in the 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.

3. Pacific Gas and Electric Company (PG&E) is authorized to implement the attrition revenue requirement increases for the years 2015 and 2016 in accordance with methodology detailed in Appendix D, Table 2 to this decision. PG&E shall include the fixed revenue requirement attrition amounts for 2015 and 2016, respectively, as set forth in Appendix D, in its Annual Electric True-Up and Annual Gas True-Up filings.

4. 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.

5. The adjustments to the operations and maintenance expense and the capital expenditures forecasts of Pacific Gas & Electric Company, as set forth in the Findings of Fact and Conclusions of Law in this decision, are adopted as summarized in Appendix C, Table 1.

6. Pacific Gas and Electric Company (PG&E) shall file its next General Rate Case for test year 2017 pursuant to the applicable Rate Case Plan adopted in Decision 89-01-040, as modified PG&E is authorized to establish a two-way balancing account to track and adjust for the difference between authorized and actual expenses incurred relating to Major Work Categories DE natural gas distribution leak survey, FI leak repair, Maintenance Activity Types (MAT) HY 7 meter set leak repair and FHK atmospheric corrosion inspection costs; and tee cap repair embedded in MAT JSL. PG&E shall file a Tier 1 Advice Letter within 45 days of the effective date of this decision to establish this balancing account. The Advice Letter shall be effective on January 1, 2014, subject to Energy Division determining that it is in compliance with this decision.

7. Any subsequent rate adjustments to recover costs recorded in the balancing account shall be subject to the restrictions, rate caps, and limitations set

forth below: For cost cap purposes, the amounts shown apply individually to each cost element on an annualized basis with no additional allowance for cost escalation, as follows:

	$ in Millions
DE Natural Gas Leak Survey	$ 33,840
FI Leak Repair	102.141
HY7 - Meter Set Leak Repair	7.756
FHK Atmospheric Corrosion Inspection	4.737
Total	$148.474

8. The balance in the two-way balancing account referenced in Ordering Paragraph 6 (including interest) shall be transferred to the appropriate accounts (Core Fixed Costs Account and Non-core Customer Charge Account) for refund to or recovery from customers in the following year through the Annual Gas True up advice letter filing. Franchise Fees and Uncollectibles expense shall be added as appropriate to the Core Fixed Cost Account and Non-core Account. For work for which an average unit cost is adopted, balancing account cost recovery will be based on actual units of work, but limited on an overall basis to adopted average unit costs. For applicable work that was not forecast based on unit costs, recoverable balancing account costs will be based on actual recorded costs.

9. Pacific Gas and Electric Company (PG&E) is authorized to establish a two-way balancing account to recover the costs of responding to major emergencies and catastrophic events recorded in Major Work Category IF and 95, where those costs cannot be recovered through the Catastrophic Event Memorandum Account mechanism. PG&E shall file a Tier 1 advice letter within 45 days of the effective date of this decision to implement this authorization, to

become effective on January 1, 2014, subject to Energy Division determining that it is in compliance with this decision.

10. Pacific Gas and Electric Company is authorized to continue the one-way Vegetation Management Balancing Account and Incremental Inspection and Removal Cost Tracking Account.

11. Pacific Gas and Electric Company's proposed rate design for light-emitting diode street lights is adopted.

12. The Center for Electrosmog Prevention request to open investigations into Pacific Gas and Electric Company's records management practices and requests related to wireless infrastructure are denied.

13. The California Coalition of Utility Employees' proposal is denied for a one-way balancing account for the Pole Replacement Program.

14. The Utility Reform Network's proposal is denied for a combined memorandum account for the Electric Distribution Geographic Information System/Asset Management project and Workforce Mobilization projects in the Operations Technology.

15. The Utility Reform Network's proposal is denied to charge Pacific Gas and Electric Company's website users with a new online administrative fee for Customer Connections Online.

16. The Modesto and Merced Irrigation Districts' proposal is granted that Pacific Gas and Electric Company (PG&E) be required to provide cost information regarding all planned electric capacity distribution expenses by distribution planning area (DPA) and that the Commission evaluates PG&E's proposed revenue requirement for such distribution projects and upgrades by DPA. PG&E is directed to comply with this requirement.

17. The California City-County Street Light Association proposal is denied that Pacific Gas and Electric Company include decorative streetlights in the light-emitting diode Replacement program.

18. Pacific Gas and Electric Company (PG&E) is authorized to close its Service Disconnection Memorandum Account and to recover the recorded costs through PG&E's existing annual electric and gas true up rate processes.

19. Pacific Gas and Electric Company is authorized to consolidate ongoing cost recovery of the capital-related revenue requirement associated with the SmartMeter™ program up to the authorized cost cap with the 2014 General Rate Case revenue requirement.

20. Pacific Gas and Electric Company is authorized to close the electric and gas SmartMeter™ Balancing Accounts, including the elimination of the SmartMeter™ Benefits Realization Mechanism, and the electric and gas Meter Reading Cost Balancing Accounts.

21. Pacific Gas and Electric Company is authorized to end SmartMeter™ program reporting requirements.

22. The Utility Reform Network's (TURN's) proposal calling for an independent audit of SmartMeter costs and benefits will be further addressed following receipt of further information regarding how much the audit will cost and how it will be funded. Pacific Gas and Electric Company, TURN, and Commission staff are directed to meet and confer to determine a joint estimate of the funding required for such an audit, and to jointly file and serve an estimate of the required funding within 60 days of the effective date of this decision.

23. Pacific Gas and Electric Company (PG&E) is authorized to implement a two-way balancing account for PG&E's Opt-Out related costs and revenues related to the SmartMeter™ program. PG&E shall file a Tier 1 advice letter

within 45 days of the effective date of this decision to implement this authorization to become effective on January 1, 2014, subject to Energy Division determining that it is in compliance with this decision.

24. Pacific Gas and Electric Company (PG&E) is authorized to implement a two-way balancing account for tracking the capital and expenses associated with new Federal Energy Regulatory Commission Hydro licensing implementation and for nuclear energy safety and security related rulemakings and orders. PG&E shall file a Tier 1 advice letter within 45 days of the effective date of this decision to implement this authorization, to become effective on January 1, 2014, subject to Energy Division determining that it is in compliance with this decision.

25. The authorized balancing account for the hydroelectric licensing and license conditions costs shall include both post-2013 capital and expense Major Work Categories (applicable portions of MWC KJ for expense and MWC 11 for capital).

26. The authorized balancing account for new nuclear energy safety and security program costs mandated by the Nuclear Regulatory Commission shall include costs recorded in Major Work Categories (MWCs) BS for expense and MWC 20 for capital. The two-way balancing account shall accumulate the difference between recorded and adopted expense and post-2013 capital revenue requirements associated with these MWCs.

27. In its next General Rate Case, Pacific Gas and Electric Company shall return to customers any amounts below the forecasted revenue requirements or seek recovery of any amounts above the forecasted revenue requirements recorded to the balancing accounts for hydroelectric licensing and license conditions and Nuclear Regulatory Commission rulemaking activities. The

balances in these accounts (including interest) shall be transferred to the Utility Generation Balancing Account for refund to or recovery from customers through the Annual Electric True up process.

28. Pacific Gas and Electric Company (PG&E) is authorized to credit back to customers funds received from the successful litigation with the Department of Energy in accordance with the procedures set forth joint recommendation of PG&E, The Utility Reform Network and Marin Energy Authority, as set forth and adopted in Appendix F-5.

29. The Alliance for Nuclear Responsibility Proposals to limit recovery of Pacific Gas and Electric Company's (PG&E) nuclear operation costs, as detailed in Section 6 and in the applicable Conclusions of Law of this decision, is granted to the extent noted below.

a. PG&E is directed to transfer $4.84 million in Long Term Seismic Plan (LTSP) Costs from its forecasted revenue requirement in this proceeding to the Diablo Canyon Seismic Study Balancing Account (DCSSBA) previously adopted in Decision (D.) 12-09-008. The LTSP costs shall be subject to the same Energy Resource Recovery Account Compliance proceeding and Tier 3 Advice Letter provisions adopted for the DCSSBA in D.12-09-008. PG&E shall file an Tier 1 advice letter to modify its existing DCSSBA tariff to reflect this authorization to include the costs for the LTSP. The tariff modification shall be for an effective date of January 1, 2014.

b. PG&E is directed file in its next General Rate Case a satisfactory plan to comply with California Energy Commission recommendations regarding the transfer of spent fuel to dry cask storage in its Assembly Bill 1632 Report. PG&E's forecast of $26.1 million to construct the remaining five pads at the Independent Spent Fuel Storage Installation in 2014 is approved subject to and conditional on PG&E's compliance with this directive.

30. Pacific Gas and Electric Company's (PG&E) depreciation proposals for average service lives and, survivor curves as set forth in Appendix C, Table 13 are adopted and PG&E shall use them to calculate depreciation expense.

31. The negative salvage rates for the asset accounts as set forth in Appendix C Tables 12 and 13 are adopted. For rate setting, Pacific Gas and Electric Company shall use them to calculate depreciation expense.

32. The Division of Ratepayer's Advocates' recommendation to change the computation of Pacific Gas and Electric Company's Allowance for Funds Used During Construction rate by lowering equity returns and imputing short term debt is denied.

33. The Settlement Agreement among The National Asian American Association, the Ecumenical Center for Black Church Studies, The Chinese American Institute for Empowerment, The National Hmong American Farmers, The Burmese American Institute for Corporate Responsibility, and Pacific Gas and Electric Company (PG&E), as set forth in Appendix F-1, (Settlement Agreement) is approved and adopted. The funding allocations prescribed in the Settlement Agreement are hereby approved, and PG&E is directed to implement the provisions and requirements of the Settlement Agreement as set forth in Appendix F-1.

34. The additional requirements to the Settlement Agreement, as agreed by the settling parties in response to comments are also adopted, as follows, requiring Pacific Gas and Electric Company:

a. To expand current surveys of its service area that gauge customer understanding of safety and low-income bill assistance programs.

b. To devote 45% of all Customer Care Targeted Residential Rate Education and Outreach funding up to $2.8 million per year for specified outreach activities

c. To invite low –income and community-of-color advocates to participate on an existing customer advisory panel as specified in the Settlement.

d. To provide testimony in the 2017 General Rate Case on its efforts to engage with community –based organizations, to hire minority-owned businesses for auditing work, and to promote diverse hiring at all levels.

e. To put out for bid its overall auditing function prior to 2017.

f. To meet with key diverse business enterprise organizations attending the annual General Order (GO) 156 en banc proceedings, to discuss cooperative methods for achieving GO 156 goals and other issues as specified in the Settlement.

35. Pacific Gas and Electric Company (PG&E) shall provide the following in its 2017 General Rate Case (GRC) testimony:

a. A report on its efforts to expand current surveys as required by the Settlement, as noted above;

b. A discussion of whether the understanding of hard-to-reach communities is comparable to the understanding of the general residential customer community regarding safety and low-income assistance programs;

c. Proposed targeted remedial action if hard-to-reach communities demonstrate a lower level of understanding of safety and low-income assistance programs (to reduce the knowledge differential), or broad remedial action if the results show generally that customer understanding of these programs is low.

d. The annual expenditure of the Targeted Outreach funding addressed in the Settlement by county in 2015, as well as during that portion of 2016 for which data is available at the time PG&E files its 2017 GRC application; and

e. A list of those community-based organizations (CBOs) which have received Targeted Outreach funding pursuant to the

> Settlement, including the amount of money allocated to each CBO recipient and the location of and communities served by those CBOs.

36. The joint proposal between Pacific Gas and Electric Company (PG&E) and the Center for Accessible Technology set forth in Appendix F-4 is adopted. Accordingly, PG&E is directed to implement the terms of the settlement as set forth therein.

37. The Small Business Utility Advocates/Pacific Gas and Electric (SBUA/PG&E) settlement agreement is approved and adopted as set forth in Appendix F-2. Accordingly, PG&E is directed to implement the terms of the SBUA/PG&E settlement in accordance with the provisions and requirements as set forth therein.

38. The method set forth in the Joint Exhibit (Exhibit 330) as jointly sponsored by Pacific Gas and Electric Company (PG&E), Marin Energy Authority, and The Utility Reform Network for crediting the Department of Energy litigation proceeds to generation rates and nuclear decommissioning rates is adopted. PG&E directed to implement to proposal as prescribed in Appendix F-5.

39. The Partial Settlement Agreement among Pacific Gas and Electric Company, The Utility Reform Network, and Marin Energy Authority, regarding allocation of certain administrative and general costs from distribution to Customer Program revenues, as set forth in Appendix F-3 is approved and adopted. In accordance with the settlement, as amended, costs associated with applicable employee benefits that are currently allocated to Distribution and recovered in the General Rate Case (GRC) revenue requirement shall be reallocated to Customer Programs and the balancing accounts attributable to the Customer Programs as prescribed in Appendix F-3. This reallocation reduces the

GRC revenue requirement by $27 million and increases the revenue requirements for the Customer Programs in an equal amount.

40. Pacific Gas and Electric Company (PG&E) is required to present the following in its 2017 General Rate Case (GRC):

a. 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.

b. Prioritization of projects and programs in the 2017 GRC by using risk-based criteria and demonstration how the projects and programs it is forecasting mitigate the system safety risks listed on PG&E's risk registers.

c. Enhanced testimony on its overall risk program from its Chief Risk Officer as well as Lines of Business-specific risk testimony from the risk or asset management leads from Electric Operations, Energy Supply and Gas Operations

41. Pacific Gas and Electric Company (PG&E) is authorized to continue use of the current Z-factor process for events outside its control and that exceed a $10 million threshold. If PG&E requests recovery of costs through the Z-factor, it must file an application to make its request.

42. The Energy Division workpapers supporting the modeling used to produce the Results of Operations Tables in the appendices of this decision, in support of the adopted revenue requirements for 2014 through 2016, are received into the record of this proceeding, and identified as Exhibit ALJ-1. Upon the issuance of this decision, the Energy Division will provide a copy of these workpapers to Pacific Gas and Electric Company (PG&E) and the Office of Ratepayer Advocates. Other parties to the proceeding seeking to obtain access to the workpapers must first enter into a non-disclosure agreement with PG&E, and then contact Energy Division to arrange to receive a copy.

43. The motion filed by the City and County of San Francisco is granted for official notice of the documents attached and identified therein as "Exhibits A through M" to the Declaration of Jonathan Cherry, filed on September 19, 2013.

44. The proceeding remains open for the purpose of addressing prospective recommendations in the three consultant reports referenced in the assigned Commissioner's Amended Scoping Memo dated June 9, 2014.

45. Pacific Gas and Electric Company is authorized to discontinue complying with the requirement previously instituted in Decision 04-05-055 to file on annual report with the Commission and the Division of Ratepayer Advocates (now the Office of Ratepayer Advocates) describing and evaluation efforts to improve PG&E's web site.

46. Pacific Gas and Electric Company is authorized to recover $21.3 million, which is $1 million above the cost recovery amount authorized in Decision 10-04-028, for fuel cell projects.

47. The procedural rulings made by the Administrative Law Judge through the course of this proceeding are affirmed.

This order is effective today.

Dated _____, at San Francisco, California.

Appendix A

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(END OF APPENDIX A)

APPENDIX B

List of Acronyms

ACRONYMS	MEANING
A&G	Administrative and General
A.	Application
A4NR	Alliance For Nuclear Responsibility
AB	Assembly Bill
ABS	Advanced Billing System
AC	Atmospheric Corrosion
ACHQ	Alternative Company Headquarters
ADA	Americans with Disabilities Act
AEOC	Alternative Emergency Operations Center
AFUDA	Allowance for Funds Used During Construction
AGA	American Gas Association
AHT	Average Handle Time
ALARP	As Low As Reasonably Practicable
AM	Asset Management
AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
APS	Advanced Planning/Scheduling
ARA	Attrition Rate Adjustment
ASA	Average Speed of Answer
ASL	Average Service Life
ATS	Applied Technology Services
BCG	Boston Consulting Group

CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operator
CAL FIRE	California Department of Forestry and Fire Protection
CAL-SLA	California City-County Street Light Association
CARB	California Air Resources Board
CAT	Customer Advocacy Team
CC&B	Customer Care and Billing
CCA	Community Choice Aggregation
CCEEB	California Council for Environmental and Economic Balance
CCFT	California Corporate Franchise Tax
CCO	Customer Connection Online
CCSF	City and County of San Francisco
CCUE	Coalition of California Utility Employees
CEC	California Energy Commission
CEDSA	Centralized Electric Distribution System Analysis
CEMA	Catastrophic Event Memorandum Account
CEO	Chief Executive Officer
CEP	Center for Electrosmog Prevention
CES	Customer Energy Solutions
CforAT	Center for Accessible Technology
CI&S	Customer Insight and Strategy
CIRM	Customer Interaction and Relationship Management
COE	Critical Operating Equipment
CP	Cathodic Protection
CP	Change of Party
CPI	Consumer Price Index
CSRs	Customer service representatives

CTA	California Taxpayers Association
CUE	California Utility Employees
CWIP	construction work in progress
D&O	Directors and Officers
D.	Decision
DCC	Distribution Control Centers
DCCC	Distribution Control Center Consolidation
DCPP	Diablo Canyon Power Plant
DCSSBA	Diablo Canyon Seismic Studies Balancing Account
DIMP	Distribution Integrity Management Program
DOE	Department of Energy
DOELBA	Department of Energy Litigation Balancing Account
DPA	Distribution Planning Area
DRA	Division of Ratepayer Advocates
DSO	Distribution System Operations
ECM	Enterprise Content Management
ED	Electric Distribution
EDM	Electric Distribution Maintenance
EDS	Energy Data Services
EE	Energy Efficiency
EEI	Edison Electric Institute
EFO	Earnings from Operations
EG	Electric Generation
EHS	Environmental Health and Safety
EOIP	Electric Operations Improvement Plan
EP	Energy Procurement
EPUC	Energy Producers and Users Coalition

ERM	Enterprise Risk Management
ERP	Emergency Recovery Program
ERRA	Energy Resource Recovery Account
ESC	Engineers and Scientists of California
ESOP	Employee Stock Option Plan
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FIT	Federal Income Tax
FLISR	Fault Location, Isolation, and Restoration
FMO	Field Meter Operations
FTE	Full-Time Equivalent
GD	Gas Distribution
GEEM	Gas Effectiveness Evaluation and Mitigation
GEMS	Gas and Electric Meter Services
GHG	Greenhouse Gas
GIS	Geographic Information System
GMC	Ground Motion Control
GO	General Order
GPRP	Gas Pipeline Replacement Program
GPTC	Gas Piping and Technology Committee
GRC	General Rate Case
GSR	Gas Service Representative
HBGS	Humboldt Bay Generating Station
HPR	High Pressure Regulator
HPSV	High Pressure Sodium Vapor
HR	Human Resources

HSR	High-Speed Rail
I.	Investigation
IAM	Identity and Access Management
IBEW	International Brotherhood of Electrical Workers
IDPEM	Interval Data Processing and Exceptions Management
IOU	Investor-Owned Utilities
IPRP	Independent Peer Review Panel
IRP	Independent Review Panel
IRV	Internal Relief Valves
ISFSI	Independent Spent Fuel Storage Installation
IT	Information Technology
kWh	Kilowatt-hour
LCC	Land Conservation Commitment
LCP	Land Conservation Program
LCPIA	Land Conservation Plan Implementation Account
LED	Light-Emitting Diode
LEP	Limited English Proficient
LOB	Lines of Business
LTSA	Long-Term Service Agreements
LTSP	Long Term Seismic Plan
M&S	Materials and Supplies
MAME	Meter Asset Management and Engineering
MAT	Maintenance Activity Type
MEA	Marin Energy Authority
MID	Modesto/Merced Irrigation District
MLP	Materials, Logistics, and Planning
MMP	Meter Maintenance Person

MOU	Memoranda of Understanding
MRCBA	Meter Reading Cost Balancing Accounts
MRTU	Market Redesign and Technology Upgrade
MWC	Major Work Category
NAICS	North American Industry Classification System
NB	New Business
NEBS	Non-Energy Billing System
NEI	Nuclear Energy Institute
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
O&M	Operations and Maintenance
OFCCP	Office of Federal Contract Compliance Programs
OOR	Other Operating Revenues
ORA	Office of Ratepayer Advocates
OSPP	Oil Spill Prevention Projects
PAS	Publicly Available Standard
PCWA	Placer County Water Agency
PDP	Peak Day Pricing
PEV	Plug-in Electric Vehicles
PG&E	Pacific Gas and Electric Company
PHC	Prehearing Conference
PHEV	Plug-In Hybrid Electric Vehicle
PHMSA	Pipeline Hazardous Materials Safety Administration
PIP	Policy and Integrated Planning
PM	Plant Maintenance
POU	Publicly-Owned Utilities

PPMT	Project Portfolio Management Tool
PPP	Public Purpose Program
PSEP	Pipeline Safety Enhancement Plan
PTC	Permit to Construct
PWR	pressurized water reactor
QAP	Quality Assurance Program
R&D	Research and Development
R&R	Rewards and Recognition
R.	Rulemaking
RDW	Rate Design Window
RIM	Ratepayer Impact Measure
RO	Results of Operations
SAP	Systems, Applications & Products
SAS	Substation Asset Strategy
SB	Senate Bill
SBAs	SmartMeter™ Balancing Accounts
SBUA	Small Business Utility Advocates
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison Company
SED	Safety and Enforcement Division
sf	Square feet
SG	Steam Generator
SIT	State Income Tax
SLIP	Streetlight Inventory Project
SMB	Small and Medium Business
SMC	Scheduled Meter Change
SMOOP	SmartMeter™ Opt-Out Program

SMU	SmartMeter™ Upgrade
SPR	Simulated Plant Record
SRM	Supplier Relationship Management
SRTC	San Ramon Technology Center
SSHAC	Senior Seismic Hazard Analysis Committee
STIP	Short-Term Incentive Plan
TAMA	Tax Act Memorandum Account
TCS	Total Compensation Study
TGRAL	Transfer Ground Rocker Arm Line
TGRAM	Transfer Ground Rocker Arm Main
TM2	Tariff Manager 2
TOU	Time of Use
TS	Transportation Services
TSL	Telephone Service Level
TURN	The Utility Reform Network
UCC	Unbundled Cost Category
UNFFR	Upper North Fork Feather River
USA	Underground Service Alert
VFD	Variable Frequency Drive
VHT	Virtual Hold Technology
VOS	Value of Service
WRO	Work at the Request of Others

(End of Appendix B)