BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

OPENING BRIEF OF THE DIVISION OF RATEPAYER ADVOCATES

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1 SUMMARY AND INTRODUCTION – PG&E'S 2014 GENERAL RATE CASE

1.1 Policy Overview

On November 15, 2012, Pacific Gas and Electric Company (PG&E) filed this General Rate Case (GRC) Application seeking authority to increase its gas and electric distribution and electric generation base revenue requirements by $1.282 billion for the Test Year, 2014.[1] PG&E also asked for additional increases in 2015 and 2016 for a 3-year cumulative revenue increase of $5.33 ***billio***n dollars.[2]

According to the Assigned Commissioner's Ruling and Scoping Memo (Scoping Memo), "[t]he principal scope of issues in this proceeding revolve around the determination of the extent that the needs and costs identified by PG&E are just and reasonable and should be reflected in retail rates."[3] As the Scoping Memo noted, PG&E is requesting "significant increases" in rates for its electric distribution, gas distribution and electric generation operations.[4]

This is the first GRC application PG&E has filed since the San Bruno pipeline explosion in September, 2010. In March 2012, the Executive Director of the Commission sent a letter to PG&E saying, in part, that "PG&E's shareholders should fund three sets of consultants hired and overseen by Commission staff to review PG&E's safety and security proposals related to generation, the electric system and the gas system and provide the parties and the Commission information on the quality and cost-effectiveness of the safety and security proposals made by PG&E."[5]

While the introduction of consultants hired and overseen by Commission staff is unusual in a GRC, safety and security issues have always been part of General Rate Cases. For years, PG&E has asked for ratepayer funding for projects it said were necessary for safety and security. And for years, as is now apparent, PG&E has received ratepayer funding for those projects. Unfortunately, PG&E did not always spend the safety and security funding it received for those purposes.

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[1] Assigned Commissioner's Ruling and Scoping Memo, (Scoping Memo), p. 1.

[2] Ex. 69 (DRA-1), p. 1.

[3].Scoping Memo, p. 3.

[4] Scoping Memo, p. 3.

[5] Ex. 51 (PG&E-16), p. 4A1.

There is considerable evidence in this record of PG&E asking for money for a particular project, and getting it, and then not doing the work. For example, according to the Focused Financial Audit of Overland Consulting, "PG&E assigned a relatively low funding priority to long-term gas safety programs during the audit period [1999 to 2010]. PG&E generally viewed long-term safety programs as discretionary spending that could be deferred to meet its overall budget targets."[6] According to the Report of the Liberty Consulting Group, PG&E's "… operating plan is usually based upon capital and operating expenses near the indicative authorized levels from the GRC with a general goal of earning the authorized return on equity for the relevant budget year."[7]

Throughout its testimony, PG&E criticizes DRA and other intervenors for failing to recognize that there are "new" safety standards.[8] There is nothing "new" about the requirement that PG&E provide safe and reliable service. Since at least 1915, it has been the law in the State of California that:

> Every public utility shall furnish, provide and maintain such service, instrumentalities, equipment and facilities as shall promote the safety, health, comfort and convenience of its patrons, employees, and the public, and as shall be in all respects adequate, efficient, just and reasonable.[9]

PG&E's ratepayers have been paying PG&E all along to maintain its facilities in such a way as to provide safe and reliable service. Yet, judging from PG&E's requests now for funding of such basic safety measures as maintaining records that accurately reflect the properties and conditions of assets in the field,[10] PG&E has not been operating or maintaining its system as it has always been required to do.

DRA and others have questioned how many times PG&E's ratepayers should be required to pay for the same thing. DRA hopes the Commission will evaluate PG&E's request here

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[6] Ex. 169, Focused Financial Audit of the Pacific Gas & Electric Company's Gas Distribution Operations of Overland Consulting (Overland Report), p. 1-3.

[7] Ex. 168, Liberty Consulting Report, p. 30.

[8] *See, e.g.,* Ex. 51 (PG&E-16), pp. 1-4, 2-4.

[9] Statutes of California 1915, Chapter 91, §13(b).

[10] *See, e.g.*, Ex. 74 (DRA-6), p. 13.

against PG&E's performance, and adopt a revenue requirement that allows for necessary system improvements, but recognizes what PG&E's ratepayers have already paid for them.

1.2 PG&E's Request

PG&E's Application requests Commission authorization of a CPUC-jurisdictional base rate revenue requirement of $8.111 billion for the utility's electric distribution, gas distribution, and electric generation operations, to be effective January 1, 2014.[11] This is an increase of $5.33 ***billion*** over the 3-year GRC period.[12] In its Application, PG&E requested revenue increases of $587 million in Electric Distribution, $486 million in Gas Distribution, and $209 million in Electric Generation for the Test Year.[13]

PG&E estimated the bill impact for an electric residential customer using an average of 55 kWh/ month would be a $4.61 increase (about 5.2%) per month from $89.36 to $93.97, while a customer using an average of 850 KWh/month would experience an $18.34 increase (about 10%) per month, from $188.41 to $202.75.[14] For a gas residential customer using an average of 37 therms/month, PG&E estimated a $7.06 increase (about 15.3%) per month, from $46.13 to $53.18.[15]

In its testimony, DRA recommended a 3-year cumulative increase of $9 million. This is comprised of a $162 million (2.4%) decrease in 2014, and increases of $168 million in 2015, and $$159 million in 2016.[16] DRA's recommendations would lead to a decrease of approximately $1.31 (about 1.5%) per month to a residential customer's electric bill, and approximately a $1.23 (about 2.7%) per month increase to a residential customer's gas bill.[17]

The actual dollar amounts PG&E and DRA are now recommending have changed during the course of this proceeding. In December, 2012, the Commission issued a decision adopting a 8.06% rate of return on rate base for PG&E, as opposed to the 8.79% rate of return that had been

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[11] Application, (A.12-11-009), p. 3.

[12] Ex. 69 (DRA-1), p. 1.

[13] Ex. 69 (DRA-1), p. 1.

[14] A.12-11-009, p. 3.

[15] A.12-11-009, p. 3.

[16] Ex. 69 (DRA-1), p. 1.

[17] Ex. 69 (DRA-1), p. 10.

in effect when PG&E filed its GRC application. DRA used the December 2012 rate of return for its calculations.[18]

In March, 2013, PG&E served an Errata to its November 2012 filing. DRA's testimony and Results of Operations (RO) Model do not reflect changes to PG&E's forecasts if they were impacted by that Errata. DRA also submitted Errata, so the current total proposed revenues DRA recommends has changed from what it was when DRA submitted its testimony in May 2013.[19] Changes by individual area, however, are noted in the specific sections, below.

DRA's proposal includes ratepayer funding for all the projects PG&E justified. At various times in the course of this proceeding, PG&E has argued that DRA and other parties "ignored" PG&E's testimony on its risk and safety programs.[20] PG&E is mistaken. For all capital projects and maintenance programs, including those that are intended to improve safety and/ or reliability, it is PG&E's responsibility to provide evidence that shows that the proposal is necessary and / or cost effective. It is not enough for PG&E to call a project "safety" and expect the Commission to authorize ratepayer funding for it. Yet, all too often, it seems that is what PG&E has done. The Liberty Consulting Report, for example, said that it found PG&E:

> …to overuse the safety label. Much of what the Company designates as safety falls under what others consider baseline and reliability work and under what we consider to be more appropriate classifications as well.[21]

According to PG&E, "DRA's report is out of step with state law and good public policy."[22] As support for this, PG&E cites to Section 963(b)(3) of the Public Utilities Code which requires that "the [C]omission and each gas corporation place safety of the public and gas corporation employees as the top priority." But PG&E omits the rest of that part of the statute which says that "the Commission shall take all reasonable and appropriate actions necessary to

[18] Ex. 69 (DRA-1), p. 2, footnote 5.

[19] 27 RT 3638, Tang/DRA.

[20] Ex. 51 (PG&E-16), p. 1-3.

[21] Ex. 168 (Liberty Consulting Report), p. 14.

[22] Ex. 51 (PG&E-16), p. 1-3.

carry out the safety priority policy of this paragraph *consistent with the principle of just and reasonable cost based rates."*[23]

In PG&E's last GRC Application, it sought a revenue requirement increase of approximately $1.25 billion dollars for test year 2011.[24] According to testimony PG&E filed in 2009 with that Application, "safety" was "… the key to the success of our operations, both because of its basic human impact and because excellence in safety is a leading indicator of overall operational excellence."[25] As discussed in more detail below, numerous projects PG&E included in this Application for safety and reliability, it included in the last GRC for safety and reliability. And PG&E did not do them. So now, when PG&E comes in seeking another $1.2 billion increase and says, again, that "safety is a top priority," the Commission should be mindful of the rest of Section 963(b)(3) and "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."[26]

1.3 Impacts on Customers and the Local Economy

In this GRC, as it did in the last one, PG&E included a report that purports to show the "Economic Impact of PG&E Proposed Generation, Distribution & Related Infrastructure Investments."[27] DRA recommends this report be given no weight and that any expenses associated with it be removed from recorded data in future GRCs.

In this GRC, PG&E paid a firm called the Economic Development Research Group "… to provide an assessment of the economic impact of its proposed generation and distribution investments."[28] PG&E uses that report to argue that PG&E's "…planned spending will contribute significantly to California's economic recovery," and that approval of PG&E's $4.0

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[23] Ex. 51 (PG&E-16), p. 1-4 citing Public Utilities Code §963 (b)(3), emphasis added.

[24] See Ex. 69 (DRA-1), p. 19, Table 1-8 "Year" TY 2011, and "Requested Increase over Prior Year" $1.257 billion.

[25] 12 RT 945, Johns/PG&E; Ex. 172, p. 1-4.

[26] Ex. 51 (PG&E-16), p. 1-4 citing Public Utilities Code §963 (b)(3), emphasis added.

[27] Ex. 1 (PG&E-1), Attachment 5A.

[28] Ex. 1 (PG&E-1), Attachment 5A, p. 1, "Study Objective."

billion investment "…will provide significant benefits for the economy in PG&E's service territory as well as California as a whole."[29]

In its last GRC, PG&E offered a similar study by another consulting firm. That study purported to show the "Economic Impacts of Proposed Capital Expenditures by the Pacific Gas and Electric Company in Northern and Central California."[30] The TY 2011 study claimed that, if PG&E's proposal in that case were adopted, "[o]n average more than 16,000 jobs are created per year. Further, these jobs are skilled and high paying providing a real labor income of more than $80,000 per employee and producing high value added of more than $132,000 per employee measured at 2011 prices."[31]

In an attempt to verify this claim from PG&E's last GRC, DRA asked PG&E how many jobs were created in each of the three years, what those jobs were, what the real labor income per employee was, and what the 'high value added" was, measured at 2011 prices. PG&E's response was that it had not verified the predictions of the study from the 2011 GRC. DRA asked PG&E to identify all steps the authors of the TY 2014 report study had taken to verify the accuracy of the "economic benefits" the TY 2011 report claimed to have identified. DRA was told that such an analysis was not in the current consultant's scope of work.[32] DRA asked PG&E to describe all steps PG&E had taken, or planned to take, to verify the accuracy of the "economic benefits" PG&E claimed in the TY 2011 exhibit. PG&E's response was that it had not verified the accuracy of the claimed benefits and had no plans to do so.[33]

Neither the study authors nor PG&E has made any effort to determine whether the claims about economic benefits made in the last GRC were ever borne out, and there is nothing in the record to validate the conclusions in this GRC's report. The so-called economic benefits are pure speculation.

In its TY 2009 GRC, Southern California Edison (SCE or Edison) offered a similar study purporting to show the economic benefits of its proposed capital expenditures. The Commission

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[29] Ex. 1 (PG&E-1), p. 5-15. At

[30] Ex. 173 (DRA-053, Q/A. 9-12).

[31] Ex. 173 (DRA-053, Q/A. 12.)

[32] Ex. 173 (DRA-053, Q/A 11).

[33] Ex. 173 (DRA-053, Q/A 9).

decision resolving the TY 2009 SCE GRC did not address the merits of that argument. In its TY 2012 GRC, SCE commissioned a similar study, also supposedly showing economic benefits of its TY 2012 spending plans.

The Commission decision resolving the TY 2012 Edison GRC found that:

> [t]he potential for economic benefits of capital spending is not an appropriate factor in determining whether to authorize capital expenditures which provide the underpinning of the electrical system. Instead we review capital spending to determine whether the investment is necessary for the delivery of safe and reliable electric service.[34]

The Commission should apply the same reasoning here. The Commission should give no weight to the "Economic Impact of PG&E Proposed Generation, Distribution & Related Infrastructure Investments." DRA also recommends that any costs related to this study be removed from rates in future GRCs.

1.4 Other Issues

1.4.1 Utility Fees and Membership Dues

In this GRC, PG&E seeks ratepayer funding for utility fees and membership dues. PG&E says it did not specifically forecast the amount of fees and dues embedded as part of its 2014 revenue requirement request. According to PG&E, it recorded $5.349 million of GRC-related utility fees and membership dues expenses in 2011; PG&E then escalated its 2011 actual expenses by 3% per year for three years, to estimate that it has included $5.845 million of utility fees and membership dues expenses in the 2014 GRC forecast.[35]

In discovery, DRA learned that PG&E recorded $5.961 million of GRC-related utility fees and membership dues expenses in 2012.[36] Using the 2012 recorded figure as the starting point, and escalating it by 3% per year for two years, yields an estimate of $6.324 million of GRC-related expenses for utility dues and membership fees for 2014.

In its decision resolving the Test Year 2012 GRC Application of SCE, the Commission addressed the matter of SCE's corporate membership dues and fees, stating that it was the

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[34] D.12-11-051, mimeo, pp. 21-22; 2012 Cal PUC LEXIS 555.

[35] Ex. 69 (DRA-1), Appendix 2 (PG&E's response to DRA Oral Data Request 18).

[36] Ex. 69 (DRA-1), Appendix 2 (PG&E response to data request DRA-PG&E-224-CKT)..

utility's "…burden to establish that requested funds are eligible for rate recovery…" and concluded that SCE did not accurately remove "…all lobbying, advertising, public relations, and other costs excluded from ratepayer recovery."[37] The Commission also stated that "…advancing policies of tax reduction is inherently political and ratepayers should not fund SCE's membership dues in political organizations, regardless of some attenuated potential rate benefit."[38] Ultimately, the Commission authorized $1.284 million (or 81%) of SCE's $1.586 million request for rate recovery.[39]

In response to discovery, PG&E indicated that all lobbying, advertising, public relations, and other costs excluded from ratepayer recovery, were removed from the 2011 GRC-portion of recorded expenses, and therefore not included in its 2014 forecast.[40] PG&E provided a spreadsheet that showed a breakdown of membership fees.

PG&E did not provide a breakdown of the lobbying, advertising, public relations and other costs[41] so DRA cannot confirm that these activities are not included in the utility fees and membership dues.

Consistent with the SCE 2012 GRC decision, DRA recommends that ratepayers provide funding for no more than 81% of the estimated $6.324 million in PG&E's expenses for utility fees and membership dues, i.e., that *at least* $1.202 million be removed from PG&E's 2014 forecast.[42]

1.4.2 PG&E's "Lost Its Way" Advertising Campaign

On July 17, 2012, a news article entitled "PG&E 'lost its way,' CEO admits in new $10 million ad blitz", appeared in the San Francisco Chronicle and can be found at SFGate.com, http://www.sfgate.com/bayarea/article/PG-E-s-ads-Utility-lost-its-way-3714243.php.[43] Among

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[37] D.12-11-051, *mimeo*., at p. 507.

[38] D.12-11-051, *mimeo*., at p. 507.

[39] D.12-11-051, *mimeo*., at p. 507.

[40] Ex. 69 (DRA-1), Appendix 2 (PG&E's responses to data request DRA-PG&E-235-CKT, Questions 1 and 2).

[41] 13 RT 1088-1089, Sharp/ PG&E.

[42] Ex. 69 (DRA-1), p. 14, footnote 29: For modeling purposes, this is reflected as an "Other Adjustment" in DRA's Results of Operations model.

[43] Ex. 69 (DRA-1), Appendix 3 includes a copy of this article.

other things, the article indicated that: (1) in July 2012, PG&E began its first large-scale public relations effort since the San Bruno explosion; (2) this campaign included television ads, radio spots, newspaper ads, and billboard ads; and (3) the estimated $10 million cost of this advertising campaign would be paid with shareholder money.

On January 16, 2013, a subsequent article entitled "PG&E clarifies 'lost its way' ad campaign", appeared in the San Francisco Chronicle and can be found at SFGate.com, http://www.sfgate.com/bayarea/article/PG-amp-E-clarifies-lost-its-way-ad-campaign-4200006.php?cmpid=emailarticle&cmpid=emailarticle.[44] The article discusses, among other things, how PG&E attempted to "clarify" the ad campaign.

DRA asked PG&E for details about the advertising campaign, such as supporting documentation which showed how all of the costs associated with this advertising campaign would be paid with shareholder money and not ratepayer funds. DRA requested a list of all PG&E employees who were in any way involved in the advertising campaign.45 DRA's data requests sought records that would allow DRA to assess PG&E's claim that its ratepayers did not pay, and are not paying, for the estimated $10 million cost of this advertising campaign. If information shows that ratepayers are paying costs that are supposed to be charged to shareholders, then the Commission should be aware of that fact.

PG&E initially objected to providing responses, asserting that DRA sought information that was "…not reasonably calculated to lead to the discovery of admissible evidence." PG&E provided some information, but it still is not clear how much PG&E spent on this advertising campaign, since PG&E was unwilling to provide direct answers.[46]

Thus, DRA recommends that the Commission direct PG&E to submit a late-filed exhibit in this GRC which provides a detailed breakdown of the costs and clearly demonstrates that all costs associated with the advertising campaign including, but not limited to, outside services expenses, and internal labor expenses associated with the amount of time PG&E employees were

[44] Ex. 69 (DRA-1), Appendix 3 includes a copy of this article.

[45] Ex. 69 (DRA-1), Appendix 3 includes a copy of data request DRA-PG&E-055-CKT.

[46] Ex. 69 (DRA-1), p. 16, footnote 37: In its supplemental response to data request DRA-PG&E-055-CKT, PG&E provided a list of employees (by job title) materially involved in the advertising campaign, Powerpoint slides that generally discussed how PG&E accounted for the advertising campaign costs, and copies of a below-the-line (BTL) audit report, management action plan referenced in the audit report, and a revised BTL accounting standard.

involved in the campaign (or clarifying the intent of the campaign), were removed from the 2012 above-the-line recorded data. Such costs should also be removed from 2012 historical data that is provided in PG&E's next GRC.

In its exhibits, DRA has identified several instances in which PG&E deferred maintenance, expenses, and/or capital investment, and requests ratepayer funding in this GRC. In those instances, DRA proposes that ratepayers not be required to fund those PG&E requests. In this regard, ***why did PG&E choose to spend $10 million (and approximately 1,000 person-hours[47]) on trying to repair its image rather than on improving, maintaining, and/or repairing its system?*** Considering the issue in the context of deferred maintenance, then it is debatable whether shareholders did fund the "Lost its Way" advertising campaign, i.e., one would hope that PG&E did not defer $10 million of ratepayer funding intended for maintenance activities and spend it on the advertising campaign.

1.4.3 Threats of Layoffs

In Rebuttal testimony, various PG&E witnesses say that adoption of DRA's recommendations would "…translate into nearly 3,000 fewer jobs at PG&E,"[48] "translate to laying off nearly 3,000 employees",[49] "… require PG&E to lay off nearly 3,000 employees…."[50]

PG&E made these threats in its last GRC arguing in Rebuttal there that adoption of DRA's labor adjustments "… would indicate a reduction of 3,780 employees in 2011."[51]

PG&E's last GRC settled. PG&E had requested an increase of $1.257 billion; the Commission authorized $730 million for TY 2011.[52] In 2011, PG&E increased its total headcount to 22,479 from the 2010 headcount of 21,820.[53]

In the TY 2012 Edison GRC, both the utility and the California Coalition for Utility Employees (CCUE) argued that, if the Commission were to adopt spending reductions proposed

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[47] Ex. 69 (DRA-1), Appendix 3 (supplemental response to data request DRA-PG&E-055-CKT).

[48] Ex. 51 (PG&E-16), p. 1-4, p. 26.

[49] Ex. 62 (PG&E-23), p. 1-2.

[50] Ex. 51 (PG&E-16, p. 2-7, Q/A. 14.

[51] Ex. 360 (2011 GRC Rebuttal Testimony (Ex. PG&E-18), Vol. 1, Summary), p. 1-13, A. 24.

[52] See Ex. 69 (DRA-1), p. 19, Table 1-8. Q/A. 12.)

[53] Ex. 173 (PG&E Responses to DRA_053).

by DRA or TURN, it would substantially compromise SCE's system and result in large layoffs of SCE's workforce. The Commission disagreed noting, that, [h]istorically, the Commission has made significant reductions to SCE's GRC requests, and historical evidence does not support the hypothetical results suggested by SCE and CCUE."[54]

PG&E's threats in this GRC should be given no more credence in this case than SCE's threats were given in SCE's GRC. The Commission should adopt a revenue requirement based on the record evidence.

2 LEGAL AND RATEMAKING PRINCIPLES AND OTHER GENERAL ISSUES

2.1 Legal and Jurisdictional Issues

2.1.1 Commission Jurisdiction

DRA has no comment on this issue at this time.

2.1.2 Burden of Proof

The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable; "no public utility shall change any rate... except upon a showing before the Commission, and a finding by the Commission that the new rate is justified."[55] Thus, in ratemaking applications, the burden of proof is on the applicant utility.[56]

In a 1980 decision, the Commission stated what has become a frequently quoted position on the burden of proof:

> Of course the burden of proof is on the utility applicant to establish the reasonableness of energy expenses sought to be recovered through ECAC. We expect a substantial affirmative showing by each utility with percipient witnesses in support of all elements of its application, including fuel costs and plant reliability.[57]

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[54] D.12-11-051, p. 22.

[55] Public Utilities Code §§ 451, 454.

[56] *See, e.g,* Application of Pacific Gas and Electric Company (2000) D.00-02-046, mimeo, p. 36, 2000 Cal. PUC LEXIS 239.

[57] Re Energy Cost Adjustment Clauses, (1980) 4 CPUC 2d 693, 701; D.92496.

In a later ECAC proceeding, the Commission confirmed:

> ...the fundamental principal involving public utilities and their regulation by governmental authority that the burden rests heavily upon a utility to prove it is entitled to rate relief and not upon the Commission, its Staff, or any interested party or protestant, such as TURN, to prove the contrary.[58]

The same burden of proof applies to the utility in a general rate case. As the Commission noted in a PG&E GRC decision, there is no distinction between types of ratemaking cases with respect to the utility's burden of proof:

> The inescapable fact is that the ultimate burden of proof of reasonableness, whether it be in the context of test-year estimates, prudence reviews outside a particular test year, or the like, never shifts from the utility which is seeking to pass its costs of operations onto ratepayers on the basis of the reasonableness of those costs.[59]

In its decision in SCE's TY 2006 GRC, the Commission confirmed that the burden of proof is on the utility:

> As the Applicant, SCE must meet the burden of proving that it is entitled to the relief it is seeking in this proceeding. SCE has the burden of affirmatively establishing the reasonableness of all aspects of its application. Intervenors do not have the burden of proving the unreasonableness of SCE's showing.[60]

As the Applicant in this rate case, PG&E has the burden of proving that each of its proposals is reasonable.

With the burden of proof placed on the Applicant in rate cases, the Commission has variously held that the standard the Applicant in a GRC must meet is "clear and convincing evidence"[61] or "preponderance of the evidence." [62] According to the alternate decision on the TY 2009 GRC for Southern California Edison:

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[58] Re Southern California Edison Company, (1983) 11 CPUC 2d 474, 475; D.83-05-036.

[59] Application of Pacific Gas and Electric Company (2000) D. 00-02-046, mimeo, p. 36, 2000 Cal. PUC LEXIS 239 citing Re Pacific Bell (1987) 27 CPUC 2d 1, 21, D.87-12-067.

[60] Opinion on Southern California Edison Company's Test Year 2006 General Rate Case IncreaseRequest (2006) D.06-05-016, mimeo, p. 7.

[61] Alternate Decision of President Peevey on Test Year 2009 General Rate Case for Southern California Edison Company (2009) D.09-03-025, p. 8.

[62] Application of Pacific Gas and Electric Company (2000) D. 00-02-046, mimeo, p. 36.

> ... the Commission has held that the standard of proof the applicant must meet is that of a preponderance of evidence, which the Commission has, at times, incorrectly referred to as "clear and convincing" evidence. Evidence Code 190 defines proof as the establishment by evidence of a "requisite degree of belief." We have analyzed the record in this proceeding within these parameters.[63]

Thus, in one paragraph, D.09-03-025 goes against a long line of other Commission decisions that find the standard of proof to be "clear and convincing evidence." D.09-03 025 offered no explanation of why "clear and convincing evidence" is the "incorrect" standard to apply. General rate increase proceedings going back at least as far as 1952 have held that "...a utility seeking an increase of rates has the burden of showing by clear and convincing evidence that it is entitled to such increase."[64] In fact, the Commission applied this standard in PG&E's last contested GRC Application,[65] and reiterated it in an opinion deciding applications for rehearing:

> We have historically, although not wholly consistently, applied the clear and convincing burden of proof to utilities seeking general rate increases. We applied the clear and convincing standard to PG&E in this case. This standard is applicable to all aspects of PG&E's showing. The Decision contains six pages (pp. 34-40) discussing at length both the clear and convincing standard and the substantial evidence standard. Moreover, the Decision explicitly reiterates later that "we must insist upon PG&E demonstrating, for each component of its proposed revenue requirements, that it produce **clear and convincing evidence.** To the extent it fails to do so, we **cannot grant its requested revenue** increase.[66]

In a recent GRC decision for a Southwest Gas Corporation, the Commission explicitly stated that clear and convincing evidence was necessary for a utility to meet its burden of proof:

> ... it is [the utility's] direct showing that must provide the clear and convincing evidence. Without establishing that basis, [the utility] will not have met its burden of proof.[67]

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[63] D.09-03-025, p. 8.

[64] *See, e.g.,* Southern Counties Gas Company of California (1952) 51 CPUC 533, 534; D.46876.

[65] D.00-02-046, p. 36.

[66] Order Granting Rehearing, D.01-10-031, 2001 Cal LEXIS 917 at *5 - *6 (emphasis added).

[67] Opinion Regarding Proposed General Rate Increase, (2004) D.04-03-034, mimeo, p. 7.

Why D.09-06-025 suddenly departed from this long line of precedent is not explained. DRA recommends that the Commission affirm that the proper standard of proof for GRCs is clear and convincing evidence, as it has been consistently for decades.

To meet the "clear and convincing evidence" standard, "... the applicant must produce evidence having the greatest probative value."[68] As the Commission further explained, clear and convincing evidence is "proof by evidence that is clear, explicit and unequivocal; that is so clear as to leave no substantial doubt; or that is sufficiently strong to demand the unhesitating assent of every reasonable mind."[69]

In practical terms, the utility in its application has the burden of showing that its requested level of spending is reasonable. If it does not meet this burden, particularly on account of lack of specific details of its spending, the interveners will rely on that information made available to develop reasonable proposals. The utility necessarily has much more information about its own operations than intervenors, no matter how detailed and thorough the information obtained through discovery. The utility usually includes a large amount of new material on rebuttal, information that if included earlier in the process would have answered a number of the questions raised by intervenor testimony (and which the utility often seems to blame intervenors for not knowing), and information that cannot be reviewed as thoroughly as the initial application given time constraints – only two weeks separated rebuttal testimony from the start of hearings in this proceeding, for example. The shortcomings within an intervenor's proposal do not justify adoption of a utility proposal that itself is not reasonable. It is not the burden of intervenors to prove that a utility's proposal is unreasonable. The Commission often has to weigh competing proposals and make its own findings of reasonableness based on the record evidence that does not fully adopt the proposal of a utility or an intervenor.

While DRA is not attempting to duplicate the work of the Safety and Enforcement Division (SED), DRA rejects any insinuation that it is unqualified to make cost recommendations in this proceeding that are derived from the actions PG&E asserts are

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[68] See Application of Pacific Gas and Electric Company, (2000) D.00-02-046, mimeo, p. 38, quoting from Application of PT&T Co. for A General Rate Increase, (1970) 2 CPUC 2d 89, 98-9 D.90462.

[69] Application of Pacific Gas and Electric Company, (2000) D.00-02-046, mimeo, pp. 36-37, 2000 Cal. PUC LEXIS 239. Any doubts "...must be resolved against the party upon whom rests the burden of proof." Application of PT&T Co. for A General Rate Increase, (1970) 2 CPUC 2d 89, 98-9, D.90462.

necessary to meet safety requirements. The SED consultants, in turn, did not make specific cost recommendations in this proceeding.

2.1.3 Compliance with Prior Commission Decisions

Where DRA has comments about compliance with prior Commission decisions, they are discussed in the specific Sections below.

2.2 Safety and Risk in Ratemaking

The Commission's increased focus on safety after San Bruno requires an explicit evaluation of risk in order to assign reasonable costs to ratepayers. Risk represents the probability of the occurrence of a damaging event, and by evaluating risk a utility can decide where best to devote its resources. However, PG&E did not perform such a risk assessment in conjunction with this rate application.[70] PG&E has requested a dramatic increase in costs for gas distribution, particularly capital spending, in order to improve its safety performance, without the benefit of such a risk assessment. Such a risk assessment is necessary to evaluate how PG&E should prioritize its safety efforts.

PG&E must meet all applicable laws and requirements through the costs approved in this proceeding. This application, however, was not the direct subject of state legislation addressing improved gas safety, and the Gas Safety Plan has been reviewed in a different Commission proceeding than this rate case. Yet safety, like all aspects of utility performance, comes at a price. Increased safety will cost ratepayers more, but with those increased costs comes an increased scrutiny on utility actions, particularly those of PG&E in the wake of San Bruno. Some of the same top executives involved in the final step of PG&E's budget process when San Bruno occurred are still involved in the final step of PG&E's budget process, with the same ability as before to redeploy resources away from gas spending. The Commission has varying ratemaking techniques at its disposal to address risk and ensure that PG&E's actions are specifically directed towards improving safety, with various balancing account and advice letter approaches available, as discussed below. Moreover, proceedings other than the current rate case will specifically address safety issues.

[70] Ex. 167 (Cycla), pp. iii, 3.

The Reports of the Consultants to the Safety Enforcement Division (SED) show that PG&E is at the start of a lengthy and complex effort to reform its organizational priorities and correct numerous problems associated with its deficient, past safety processes. At varying times, however, PG&E implies that this effort has already been completed, that PG&E has learned its lesson and can be trusted to improve its safety performance without continued oversight by the Commission or significant changes[71] to the traditional ratemaking approaches the Commission has employed in the past. PG&E's past safety performance was not supposed to be as poor as it was, and the public demands a higher level of accountability from PG&E in the future, especially as PG&E requests such a large, rapid increase in safety spending. PG&E requests a 170% increase in gas distribution capital spending in 2014 over actual levels in 2011.[72] PG&E's spending in 2012 lagged far behind its large estimated increased levels of spending in many areas. Its spending in the first half of 2013 in many areas is lagging behind estimates, and PG&E was unable to specify much of the work for which it requests funding in 2014 – even though such projects often require site-specific approval from owners and local municipalities and encounter delays. PG&E complains that this level of specificity for its costs is not possible in advance and should not be a basis to deny requested spending, but only offers that the delays to date will not continue into the Test Year 2014 and reduce its spending as they have in 2012 and 2013, and may in fact increase costs for 2014. PG&E continues to argue that its requested level of spending in 2014 is reasonable and achievable, even without a risk assessment.

DRA recognizes that the current circumstances may require limited deviation from the traditional approach the Commission has employed of setting a revenue requirement and allowing a utility full discretion on how to spend all of that revenue regardless of the various components of their application or the Commission's approval of components of that revenue requirement. For that reason, DRA proposed an advice letter process for gas capital spending associated with Major Work Categories (MWC) 14 & 50, the primary capital accounts for gas pipeline safety. The proposal enables PG&E to document its actual capital spending in those accounts in case it were higher than the expenditures levels proposed by DRA (based upon recent historical expenditures) , and to file an advice letter for recovery of the amount in excess,

[71] Except PG&E's proposed gas leak balancing account, *see infra* Section 3.6.2.

[72] Ex. 53 (DRA-18), p. 1-8, Figure 1-2; Tr. Vol. 13, 1137:11-22, 1139:1-1140:7 (Stavropolous).

with a cap of recovery at the amount PG&E requested in its application. DRA has also proposed a two-way (capped) balancing account for Distribution Integrity Management Program (DIMP) costs, costs of Federally-mandated regulations regarding the processes used by PG&E to keep its distribution system "integral" – i.e., whole and with as few incidents as possible that disturb the "integrity" of the system.

But "integrity" has a double meaning here, as it also means truthfulness or honesty. Just because in the last couple of years PG&E has spent more than the amounts it agreed were reasonable in a settlement reached after San Bruno does not mean, as PG&E suggests, that PG&E has already completely regained the trust of its ratepayers such that it can manage its system safely without scrutiny and direction over its practices and spending. PG&E has considerable financial incentive to improve its system safety, particularly through increased capital spending that will earn it a return on new pipelines and other materials for decades into the future. While clearly PG&E has already made improvements to its safety procedures, this is a work in progress, especially due to the lack of a completed risk assessment. In assuring that nations adhere to treaties involving nuclear and other dangerous weapons, international monitors have used the phrases "trust but verify" or "trust and verify" to guide their efforts. The Commission, ratepayers, and all stakeholders must vigorously review PG&E's actions to make sure that its spending is commensurate with improving safety. DRA's proposals are offered in in this spirit.

2.2.1 Legislative Developments

In October, 2011, Governor Brown signed Senate Bill 951, which required all gas corporations in California to submit a gas safety plan to the Commission. The Commission was required to hold a separate proceeding with a hearing by December 31, 2012 to "review and accept, modify, or reject"[73] the safety plan. Each gas corporation must "periodically review and update the plan" for Commission review. The safety plan is meant to implement 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 to carry out the safety priority policy of this paragraph consistent with the

[73] Pub. Util. Code § 961(b)(2).

principle of just and reasonable cost-based rates."[74] In Decision 12-12-009, issued in Rulemaking 11-02-019 on December 20, 2012, the Commission accepted the PG&E plan submitted on August 24, 2012, but SED (then the Consumer Protection and Safety Division, CPSD) noted that in 15 statutory categories, PG&E safety plan was deficient in 14 categories.[75] On June 28, 2013, SED found that PG&E had updated its plan and remedied these deficiencies. This updated plan was not reviewed in this proceeding.

2.2.2 CPUC Developments

On March 5, 2012, CPUC Executive Director Paul Clanon directed PG&E Executive Vice President Tom Bortorff to include in the Notice of Intent for this GRC "a risk assessment that underlies [PG&E's] rate requests" in order to satisfy the GRC's focus on safety in addition to rates.[76] The Executive Director further requested 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."[77] 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."[78] The Executive Director ordered PG&E to pay for the costs of the three consultants in this proceeding to review PG&E's safety proposals in this proceeding.[79] As will be more fully discussed in Section 2.2.3 below, PG&E failed to include such a risk assessment in this GRC.

2.2.3 Balancing Safety and Risk with Just and Reasonable Rates

In Section 2.2. above, DRA generally discussed safety and risk in ratemaking, and noted the Commission had varying ratemaking approaches to address safety and risk. The lack of a risk assessment, and the interaction between and timing of PG&E's revenue requirement request

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[74] Pub. Util. Code § 963(b)(3).

[75] D.12-12-009, Conclusion of Law 10, p. 29; Attachment A, Table 1, p. 13.

[76] Ex. 53 (PG&E-18 vol.1), p. 11A-1.

[77] *Id.*

[78] *Id.*

[79] *Id.*

in this proceeding, PG&E's budget process, and PG&E's eventual spending influences how the Commission should balance safety and risk with just and reasonable rates.

Despite the directive of the Executive Director, PG&E's GRC filing "does not explicitly include such a risk assessment and justification of its risk mitigation programs and policies."[80] Based on the GRC filing, "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."[81] As Consultant Cycla Corporation found:

> 11. *PG&E's GRC filing does not present a clear logical linkage between safety risks and activities intended to control them.* While organization of GRC filing documentation does facilitate understanding of the major activities PG&E wishes to pursue, it fails to clarify the linkage between safety risks and the activities designed to control them. In his March 5, 2013 letter to PG&E, Executive Director Clanon directed that "…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's response to this directive would be much easier to understand if the GRC filing included a section describing the linkage among: identified risks, the relative importance of these risks, activities designed to control these risks, costs associated with these control measures, and indicators PG&E proposes to monitor to evaluate the effectiveness of selected control measures.[82]

The Liberty Consulting Group, reviewing electric operations and power generation, noted that "for neither of the two units could we observe clear and strong connections between risk assessment and GRC budgeting for projects and programs."[83] Liberty further stated that:

> We were able to identify what GRC capital and O&M projects and programs PG&E identified by applying safety and security considerations. We found that an overly liberal use of the "safety" tag applied -- no doubt influenced by the focus on safety created by the March 5 letter and other circumstances. We did what we could to isolate those programs that in our judgment were truly driven predominantly by safety and security concerns, as opposed to other factors, such as reliability, compliance with other public requirements, or simply consistency with sound baseline utility operations.

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[80] Ex. 167 (Cycla), pp. iii, 3.

[81] Ex. 168 (Liberty), p. 17.

[82] Ex. 167 (Cycla), pp. 61- 62, Finding No. 11.

[83] Ex. 168 (Liberty), p. 18.

> Having made this categorization, we could not identify any that PG&E had founded explicitly on structured, analytically founded risk assessments. Our conclusion in this regard was supported by the acknowledgement of senior LOB[84] leadership that engineering and other professional judgment formed the basis for deciding what initiatives to pursue and at what levels of proposed expenditure. We 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. We could not find substantial documentation of this type of thinking or analysis, although we consider such support to be consistent with the expectations created by the March 5 letter and by the areas of inquiry included in our scope for this study.[85]

Liberty also noted that:

> Given the circumstances, we could not assess whether the degree of risk reduction can be expected to reach a level considered satisfactory from customer, public, and employee perspectives. Nor could we apply any PG&E risk assessments to determine the appropriateness of related projects and programs and of the costs associated with them.[86]

Both Liberty and Cycla, in the absence of the explicit risk assessments requested in the March 5, 2012 letter, instead directly reviewed how PG&E has identified and responded to safety issues and in the GRC filing, much as has always been done in prior rate cases, albeit without such explicit Commission safety expertise. It is an issue of first impression for this Commission how the March 5, 2012 letter's recommendations integrate with this GRC, as no previous GRC has been filed after the issuance of the letter, and the letter and accompanying consultant reports are not explicitly included in the Rate Case Plan. Given the lack of the risk assessments, PG&E has failed to respond fully to the requirements of the Executive Director, and the consultants' jobs are similarly incomplete in this proceeding, regardless of the consultants' thorough review of what PG&E actually included in its filing.

But the Commission is faced with a dilemma, as PG&E requests greatly increased costs associated with increased safety requirements without the benefit of the required risk assessment. Moreover, as will be discussed in a little more detail below in Section 2.2.3.1, Liberty concluded

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[84] Line of Business.

[85] Ex. 168 (Liberty), pp. 18-19.

[86] *Id.*, p. 19.

PG&E is not likely to have a completed risk assessment even in time for the 2017 GRC.[87] In determining the revenue requirement and whether to order balancing accounts or advice letter processes tailored to safety spending, the Commission must explicitly consider that PG&E has not yet completed the requested risk assessments that would justify and compare the safety impacts of the specific proposals presented.

2.2.3.1 PG&E's Budget Process

In its rebuttal testimony to Overland Consulting's report addressing PG&E's budget process through 2010, PG&E asserts that "PG&E has improved its budget and planning processes since the time period studied by Overland."[88] PG&E further claimed in rebutting Overland that Liberty's report[89] "comments favorably on the strides PG&E has made to improve its planning and budget process."[90] However, Liberty noted that the changes to the budget process prior to the final stage of executive approval have not yet incorporated completed risk assessments, and will likely not incorporate risk assessments even by the next GRC. Moreover, the PG&E budget process still ends with decisions made by top executives that could reallocate resources away from gas operations, as it did when the San Bruno incident occurred, with some of those same executives in charge during San Bruno still participating in the final stages of the budget process.

PG&E explains that the "threshold step in the current planning process is to identify the Company's strategic goals," and after a Risk and Compliance Session, each Line of Business develops a strategic plan called an S-1 submission.[91] "In the next stage of the planning process, the LOBs develop a detailed plan to execute on the strategies identified in the prior stage of the process,"[92] and complete an S-2 execution plan with detailed spending forecasts that are "not

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[87] Ex. 168 (Liberty), pp. 55-56.

[88] Ex. 66 (PG&E-27 Vol. 1), p. 2-1; Tr. Vol. 12, p. 958, line 23 – p. 959, line 1 (Johns).

[89] Although Overland only audited PG&E's gas distribution spending, and Liberty's review was of PG&E's electric operations, PG&E's reference to Liberty's report concedes that Liberty's comments on PG&E's budget process apply to all of PG&E's operations, both gas and electric.

[90] Ex. 66 (PG&E-27 Vol. 1), p. 2-4, *citing* Ex. 168 (Liberty), p. 58.

[91] Ex. 66 (PG&E-27 Vol. 1), p. 2-2.

[92] *Id.*

supposed to be constrained by the target budget amounts,"[93] although the "risk of not funding" impacts prioritization of work[94] and "estimated regulatory targets" are used for comparison with the budget targets.[95] In the next step, PG&E's "senior leaders responsible for the planning and budgeting process then review each LOB's execution plan, meet with the leaders of the LOBs to discuss priorities across the utility, and ultimately set budgets for each LOB."[96] PG&E is utilizing the budget process detailed in Chapter 2 of Ex. 66 in 2013 to set its 2014 budget.[97]

Liberty explicitly reviewed PG&E's "Corporate Level GRC and Risk Processes" in Section 2 of its report, and PG&E's "Risk Assessment Development" in part 2.B, the part noted above referenced by PG&E as commenting favorably on PG&E's budget process.[98] This review was specifically of the process PG&E is utilizing for its 2014 budget. Liberty noted that "[t]he development of risk assessment corporate processes continued in 2012, but their development lagged the schedule for NOI and GRC filings."[99] PG&E's Risk and Audit group "has sought to stimulate LOB engagement in robust risk assessment and management processes,"[100] and "[t]his process feeds the development of strategies, execution plans, forecasts and budgets, which PG&E intends in the future to drive GRC planning and preparation as well,"[101] although it "is not expected to reach a steady state until after what senior leadership sees as a multi-year process."[102] Liberty reported that PG&E did not meet its June 30, 2012 "goal of identifying top operational risk for each LOB and presenting them to the R[isk] P[olicy] C[ommittee],"[103] and

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[93] *Id.*, p. 2-3.

[94] *Id.*, p. 2-2.

[95] *Id.*, pp. 2-2 to 2-3.

[96] *Id.*, p. 2-3; *See* Tr. Vol. 12, 959:16-24 (Johns).

[97] Tr. Vol. 12, 959:2-6 (Johns).

[98] Ex. 66 (PG&E-27 Vol. 1), p. 2-4, *citing* Ex. 168 (Liberty), p. 58.

[99] Ex. 168 (Liberty), p. 53.

[100] *Id.,* p. 54.

[101] *Id.*, pp. 54-55.

[102] *Id.*, pp. 55.

[103] *Id.*; *see also* Tr. Vol. 26, 3333:7-17 (Bromson).

that PG&E "managers and executives later recognized that the developing risk assessment processes in 2012 'did not take well.'"[104]

Liberty next commented on the Risk and Compliance Session that feeds into the S-1 submission and S-2 execution plan[105] detailed in PG&E's rebuttal testimony as noted above.[106] Liberty stated that PG&E

> considers the early 2013 exercise within each LOB to be a preliminary and only partial test in the evolution of the risk assessment processes, which, if it develops as hoped will eventually drive the identification and assessment of risk mitigation measures, which will then flow into the corporate planning steps that eventually produce projects, programs, and initiatives, which then will produce capital and O&M forecasts, which then will drive GRC filings. **That result, we emphasize, is not what exists now, nor is likely to exist until the next GRC filing, if then.**[107]

When asked if he agreed with this statement, PG&E witness Wells did not say he disagreed:

> I don't have the context for that particular statement. I do believe that operational risk was taken into consideration as part of this GRC. Without having the benefit of the context of this particular statement, my belief is what it's referring to is the changes to our formal integrated planning process.[108]

Mr. Wells, who testified about the same budget processes reviewed here by Liberty and referenced this section of Liberty's report,[109] may have noted that PG&E took "operational risk … into consideration as part of this GRC," but that is quite different than completing the formal risk assessment as required in the March 5, 2012 letter. Mr. Wells did not disagree with Liberty's point that PG&E's new processes are not yet fully implemented, noting that PG&E is

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[104] Ex. 168 (Liberty), p. 55; *see also* Tr. Vol. 26, 3333:18 – 3334:1 (Wells).

[105] Ex. 168 (Liberty), p. 55.

[106] *See supra* Fns. 37-41 and accompanying text.

[107] Ex. 168 (Liberty), pp. 55-56 (emphasis added).

[108] Tr. Vol. 26, 3335:5-12 (Wells).

[109] Ex. 66 (PG&E-27 Vol. 1), p. 2-4, *citing* Ex. 168 (Liberty), p. 58; *see supra* Fns. 36 and 44 and accompanying text.

continuing to refine them.[110] PG&E does not dispute Liberty's conclusion that PG&E has not included a risk assessment in this GRC application, did not complete a risk assessment as part of its 2014 budget, and will not complete a risk assessment until its 2017 GRC (filed in late 2015), if then.

In the final step of the budget process, the Company's senior leaders "ultimately set budgets for each LOB."[111] Such approval at the executive level by the Company's senior leaders including PG&E President Johns, with the discretion to alter the budget recommendations made to them, remains. Mr. Johns noted that sixteen PG&E "senior leaders," including himself, will take part in the 2014 budget approval process in October, 2013.[112] Mr. Johns drew on his experience "to explain how the [budget] process works."[113] Mr. Johns confirmed that senior leaders have the discretion in this final stage to reallocate costs between Lines of Business, and have "been doing that for years."[114] PG&E's new, improved budget process still has PG&E executives with the final say on whether to modify the recommendations of S-2 execution plans. Those execution plans, as noted above, still do not incorporate the recommendations of a full risk assessment, but even when they do, perhaps by the next GRC, PG&E executives still will have the discretion to modify the recommendations at the final stage of the budget process. That final stage occurs in October of the year before the budget year, and in a GRC year, that is a full eleven months after the GRC application.

PG&E's "new and improved" budget process in this GRC thus does not incorporate a risk assessment, and will still conclude with a discretionary review by top executives. In I.12-01-007 , the investigation into the San Bruno incident in which Overland offered a review of PG&E's transmission budget process, DRA understands SED argued that PG&E executives underspent on gas transmission and reallocated monies away from gas transmission and to gas distribution. PG&E is requesting a dramatic gas spending increase, without a full risk assessment, and with full discretion for PG&E to spend the monies how they see fit and discretion for its executives to

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[110] *See* Tr. Vol. 26, 3335:13 – 3336:12 (Wells) (including reference to Ex. 66, p 2-4 citation of Liberty, Ex. 168, p. 58).

[111] Ex. 66 (PG&E-27 Vol. 1), p. 2-3; *see* Tr. Vol. 12, 962:19-25 (Bromson).

[112] *See* Tr. Vol. 12, 959:15 – 960:27 (Johns).

[113] Tr. Vol. 12, 962: 26 – 964:24 (Johns).

[114] Tr. Vol. 12, 964:25 – 965:9 (Johns).

reallocate costs away from gas, DRA's recommendation for an advice letter process for gas capital spending, and a balancing account for DIMP spending, is based partially on these factors.

2.2.3.2 Traditional Ratemaking, Balancing Accounts and Advice Letters

The Commission normally allows a utility discretion to spend its approved revenue requirement as it sees fit, without having to hew to the specific amounts delineated in a decision to determine the level of the revenue requirement, unless the Commission establishes other mechanisms for recovery, such as balancing accounts. GRC settlements are mostly structured similarly, with the underlying details leading to the amounts not applicable under so-called "black box" settlement treatment, unless different treatment is set forth in a settlement. Settlements do have an advantage over Commission decisions that parties explicitly assume the ratemaking risks approved if the Commission does not modify the Settlement, rather than having those risks imposed upon the parties in a Commission decision. The current 2011 PG&E GRC settlement includes a one-way balancing account for DIMP costs.

Under most circumstances, allowing the utility such discretion is appropriate. Neither the Commission, nor intervenors desire or have the capability to micromanage utility operations. If a utility can save money in performing a task compared to a reasonable estimate, it should have some incentive to reallocate resources to other tasks or even to retain a portion of such savings under incentives. But the current rate case application, filed in the wake of San Bruno, warrants a different approach. DRA recommends an advice letter process for specific gas capital safety spending that provides for recovery of actual capital spending the level proposed by DRA (based upon recent historical expenditure levels) and capped at the level of costs requested in PG&E's application. DRA recommends the adoption of a capped, two-way balancing account for DIMP costs.

Balancing accounts allow a utility to recover costs recorded in specified functions, and employ varied approaches to alter the spending incentives. So-called "two-way" balancing accounts set an initial level of recovery for specified spending, but allow recovery of actual spending amounts, without any limitations. DRA universally opposes such an approach because even in an area where spending is to be encouraged or is mandated, providing automatic recovery of an unlimited amount of spending not only removes any incentive for a utility to

minimize spending, but could encourage and reward overspending.[115] Two-way accounts do prevent a utility from recovering more than it spends if the amount spent is less than authorized, but it has no incentive to minimize such costs. Uncapped two-way balancing accounts also violate an axiom of forecast ratemaking, namely that a utility should not recover an amount higher than it requested. However, if a two-way balancing account includes a cap on spending, such as the level of spending requested by the utility in the application, that problem can be avoided, although in general if a spending level for a specific activity is established in a decision, a utility should not have the opportunity to recover a higher amount. PG&E's proposed uncapped, two-way balancing account for leak costs will be discussed below in Section 3.6.2.

A "one-way" balancing account, on the other hand, sets a capped amount up to which a utility can recover its actual spending on a specific area. If a utility spends less than the established amount, it only recovers its actual spending, and if it spends higher than the amount, it must find the funds for excess spending elsewhere, including the option of reprioritization of a portion of its remaining discretionary spending in other areas. A common criticism of a one-way account is that it encourages spending up to the cap even if there are savings, and discourages spending above the cap even if warranted.[116] However, for an important function which requires particular attention, safety and other needs may favor encouraging spending up to the authorized level rather than savings from spending less than that level. While hopefully the level is established such that there is no need for spending above the level, even if the utility must spend above the level to meet safety or other mandates, as long as the utility retains discretion over at least a large portion of its remaining spending under traditional ratemaking treatment, the utility has the capability of finding savings in other areas to fund spending above a one-way account cap. Indeed, under traditional ratemaking if a utility must spend more than it requested in a particular area, the recovery of this excess spending is also not guaranteed but can likewise be offset from savings in other areas. DRA's proposed capped two-way DIMP balancing account, and the Independent Panel's response to the current DIMP balancing account, will be discussed further below in Section 3.4.1.1.

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[115] As DRA witness Dao Phan noted, an uncapped, two-way balancing account "would allow [PG&E] to spend even more money than [PG&E] forecast." Tr. Vol. 28, 3836:3-16 (Phan).

[116] *See, e.g.,* Independent Panel Review, p. 107, found at Ex. 53 (PG&E-18), p. 11B-115.

DRA has proposed an advice letter process for recovery of certain gas capital costs that would have the Commission set a level of authorized capital spending in Major Work Categories 14 and 50, but would allow PG&E an opportunity to file an advice letter for recovery of any additional capital costs in these MWCs above the authorized level, capped at the level PG&E requested. In essence, the proposal is the upside portion of a capped, two-way balancing account, and would only slightly delay the recovery period of long-term capital assets. DRA has made this proposal to respond to the unique, particular circumstances of PG&E's current GRC request: the extreme size of the requested increase in gas capital specificity; the lack of specificity of many necessary details of the spending; that PG&E's spending in 2012 and 2013 to date is below its spending estimates; and the importance of this area of spending. This proposal allows PG&E the opportunity to recover all the capital costs in these MWCs it has requested in this proceeding, as long as such money is spent on these important pipeline projects. DRA will discuss its proposal in more detail below in Section 3.8.8.

2.2.4 SED Reports

2.2.4.1 Liberty Report

As noted above in Sections 2.2.3 and 2.2.3.1, the Liberty Consulting Group's report, "A Study of Risk Assessment and PG&E's GRC," noted that PG&E did not utilize a risk assessment to determine its 2014 GRC application. Liberty did review PG&E's safety measures addressing electric distribution and generation.

2.2.4.2 Cycla Report

Similar to the Liberty report, as noted above in Sections 2.2.3 and 2.2.3.1, the Cycla Corporation's "Evaluation of PG&E's 2014 Gas Distribution Filing" found that PG&E's filing in this proceeding "does not explicitly include … a risk assessment and justification of its risk mitigation programs and policies."[117] Cycla evaluated PG&E's response to the March 5, 2012 Executive Director's letter and addressed PG&E's safety measures addressing gas distribution.

Cycla summarized its objective in its report thusly:

> An objective of the California Public Utilities Commission (CPUC) is to require pipeline facility operators subject to CPUC rate regulation to explicitly consider risk in deciding which safety improvements to propose in their General Rate Case

[117] Ex. 167 (Cycla), pp. iii, 3.

> (GRC) filings. Given the magnitude of the change required both within Pacific Gas and Electric Company (PG&E) and CPUC to meet this objective, the CPUC expects that the PG&E 2014 GRC filing represents but a first step in a deliberate evolution in the way the utility identifies and evaluates the value of safety improvements. The endpoint of this evolution will be a risk-informed decision process leading to rate case filings that include knowledgeable consideration of the best means to produce superior safety performance. In moving toward attaining its objective, the CPUC has commissioned Cycla Corporation (Cycla) to evaluate the PG&E 2014 gas distribution GRC filing.[118]

Though it found that PG&E's application did not include an explicit risk assessment as directed by the March 5, 2012 letter, Cycla evaluated how well PG&E incorporated risk characterization in selecting the set of safety improvements it proposes to undertake. Cycla's primary focus was on determining how the utility's decision processes incorporated an understanding of safety risk in deciding how best to improve the safety of its gas distribution system through changes both to the pipeline system and to how PG&E manages that system. We did not attempt to evaluate whether the costs proposed in the GRC filing should be allowed or disallowed.[119]

Cycla continued that its report "addressed three basic questions:

1. What criteria should be used by CPUC to evaluate whether an operator has produced an adequate risk-informed GRC filing?
2. How does the 2014 PG&E GRC filing measure up against these criteria?
3. Are the activities proposed by PG&E necessary, is their scope appropriate, and is the proposed implementation pace reasonable?"[120]

Cycla's findings included:

- The PG&E filing does not fully satisfy the criteria established for an acceptable risk-informed budget proposal.[121]
- The model PG&E used to characterize risk for the GRC filing, originally developed to support compliance with the distribution integrity management program (DIMP) regulation, fails to satisfy many of the evaluation criteria.[122]

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[118] *Id.*, p. iii.

[119] *Id.*, p. iv. *See also* Ex. 283, Ex. 284, Tr. Vol. 3282:19-3285:24 (Wood/Gawronski).

[120] Ex. 167 (Cycla), p. 4.

[121] Ex. 167 (Cycla), p. v., p. 56, Finding No. 1.

- Verified data on system characteristics affecting risk were not available to support preparation of the GRC filing.[123]
- PG&E has presented no analysis to demonstrate the incremental value of each of its leak reduction projects.[124]
- PG&E's implementation schedule for identified RCMs is very aggressive.[125]
- PG&E's GRC filing does not present a clear logical linkage between safety risks and activities intended to control them.[126]

Cycla made the following recommendations:

1. Develop, communicate, and implement a multi-year plan to continue the evolution of risk-informed rate case budgeting.
2. Finalize the set of criteria against which GRC filings will be measured in the future, and then imbed these criteria in regulation.
3. Require PG&E to document its corresponding multi-year program to satisfy CPUC criteria.
4. Require PG&E to develop, track, and report on a set of specific performance metrics designed to measure the safety improvements actually achieved by its proposed activities.
5. Establish a monitoring program to track PG&E progress in implementing activities funded through the 2014 GRC deliberation.
6. Work together with the Pipeline and Hazardous Materials Safety Administration (PHMSA), other state safety regulators, and the pipeline industry to promote advancements in pipeline system risk modeling.
7. Work together with PHMSA, other state safety regulators, and the pipeline industry to promote exchanges of information on industry best practices that have demonstrated superior impact on safety performance.
8. Work to improve the balance between operator flexibility and accountability by focusing on greater transparency and CPUC oversight of budget revisions.
9. Determine how best to ensure that PG&E is developing and expanding its knowledge base of system and operational characteristics on which risk characterization is critically dependent.

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[122] Ex. 167 (Cycla), p. v., p. 56, Finding No. 3.

[123] Ex. 167 (Cycla), p. v., p. 57, Finding No. 4.

[124] Ex. 167 (Cycla), p. vi., p. 60, Finding No. 8.

[125] Ex. 167 (Cycla), p. vii., p. 61, Finding No. 10.

[126] Ex. 167 (Cycla), p. vii., p. 61, Finding No. 11.

10. Determine how best to use operator risk characterization developed in support of rate case filings to strengthen appropriate safety advocacy by the CPUC.[127]

For the most part, these recommendations are forward-looking to incorporate risk assessments in future GRCs, and reflect the finding that the current application did not constitute an acceptable, risk-based budget proposal.

2.2.4.3 Overland Report

Overland Consulting prepared a focused financial audit of PG&E's gas distribution operations on behalf of SED. The scope of the audit largely mirrored the scope of the transmission audit Overland also performed in I.12-01-007, the Commission's investigation of the San Bruno incident.[128] The objectives of Overland's focused audit in this proceeding were to:

- Compare actual gas distribution capital expenditures for the years 1999 to 2010 to the amounts adopted in PG&E's General Rate Cases;
- Compare actual gas distribution operations and maintenance (O&M) expenses for the years 1999 to 2010 to the amounts adopted in PG&E's General Rate Cases;
- Investigate reasons for variances between the actual and adopted amounts;
- Review PG&E's budget process and internal management reports for evidence that gas distribution resources were constrained for financial reasons during the years 2003 to 2010;
- Review gas distribution staffing levels and operational metrics for evidence of resource constraints during the years 2003 to 2010; and
- Review the financial performance of PG&E's gas distribution business over the period 2003 to 2010 to determine if earnings were sufficient to support investments in safety.[129]

Overland's key findings were:

- PG&E identified serious deficiencies in its gas distribution operations in 2007 and 2008. The evidence suggests the deficiencies date back to the mid-1990s. Management failed to detect, or chose to ignore, these deficiencies until

[127] Ex. 167 (Cycla), pp. vii-viii, pp. 62-67, Recommendation Nos. 1-10.

[128] Ex. 169 (Overland), p. 2-12; *see* Tr. Vol. 22, 2645:8-23 (O'Laughlin).

[129] Ex. 169 (Overland), p. 2-12; *see* Tr. Vol. 22, 2645:24-2647:12 (O'Laughlin).

employees publicly raised issues at PG&E's annual shareholders meeting in April 2007.

- PG&E underfunded and understaffed its gas distribution operations from the mid-to-late 1990s through 2007. Resource constraints were a significant contributing factor to the deficiencies in management, policies and procedures.
- PG&E began corrective actions starting in October 2007. However, these corrective actions produced mixed results, as demonstrated by PG&E's own internal reviews.
- PG&E's actual O&M expenses were 13% lower than adopted from 1999 to 2007. The underspending averaged $18 million a year during that period. Spending increased in 2008 and again in 2009 as PG&E implemented corrective actions. From 2008 through 2010, actual O&M was 25% higher than adopted.
- Actual capital expenditures were 6.5% lower than adopted from 1999 to 2010. PG&E spent $168 million less than adopted during that twelve year period. The underspending was concentrated in safety related categories. Safety related capital expenditures were 13.3% lower than adopted.
- PG&E's gas distribution operations earned an average actual return on equity (ROE) of 12.7% from 2003 to 2010 stated on a regulatory basis. PG&E's authorized ROE averaged 11.3% over the same period. PG&E's gas distribution revenues were $202 million higher than the amount needed to earn its authorized ROE over the eight-year study period.**130**

PG&E contested Overland's calculations, with the main difference the imputation in between rate case decisions of the levels of Capital Expenditures and Operations & Maintenance expense (O&M).[131] For O&M, the main difference was "primarily due to Overland's exclusion of some O&M expenditures related to gas matters in 2008 through 2010, particularly in 2009."[132] For 2008-2010, Overland excluded $10.2 million, $36.8 million, and $7.8 million of O&M costs as the "direct result of mismanagement" in 2007-2008.[133] Overland excluded "costs that would have been incurred at some point during the study period under reasonable management practices and costs that would not have been incurred under reasonable management

[130] Ex. 169 (Overland), pp. 1-1 to 1-2.

[131] Ex. 67 (PG&E-27 Vol. 2), p. 11; Tr. Vol. 22, 2647:15-2649:15 (O'Laughlin).

[132] Ex. 67 (PG&E-27 Vol.2), Figure 4, p. 15; Tr. Vol. 22, 2649:19-2650:20 (O'Laughlin).

[133] Ex. 67 (PG&E-27 Vol.2), Figure 4, p. 15, 16; Tr. Vol. 22, 2651:7-2652:10 (O'Laughlin); Ex. 69 (Overland), pp. 3-8 to 3-12.

practices."[134] PG&E witness O'Laughlin criticizes the exclusion of these costs as Overland just deeming these costs "non-recoverable,"[135] but he concedes that "for expenses to be included in rates they have to be just and reasonable"[136] and that he was "not responding to the specifics of the allegations"[137] of Overland regarding PG&E's management practices. Overland also recommended $2.8 million of costs be excluded relating to Rancho Cordova and the San Bruno incident as the "direct result of safety violations."[138] Moreover, while Mr. O'Laughlin testified that Overland's position about unreasonableness "should not be manifesting itself in a recorded vs. imputed adopted cost analysis," he also noted that "[t]he place where such a finding might be relevant is in determining whether a utility's proposed test year amount for a given FERC account or MWC is appropriate or overstated due to the inclusion of such costs," – such as the current general rate proceeding.[139]

PG&E further argues that Overland's adjustments for alleged non-reasonableness are improper because "Commission policy recognizes that a utility can charge actual operating expenses to above-the-line operating accounts even if it has not sought recovery of those expenses in rates."[140] D.11-01-038 by its title approved a settlement agreement,[141] which is not precedential, and the circumstances are so different than those in this proceeding that they would not be applicable anyway. DRA recommends the Commission adopt Overland's adjustments for O&M.

As for capital expenditures, the main difference between Overland and PG&E regards imputed levels of capital expenditures, as PG&E's proposed capital expenditure imputations

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[134] Ex. 69 (Overland), pp. 3-13; *see* Tr. Vol. 22, 2653:23-2654:5 (O'Laughlin).

[135] Ex. 67 (PG&E-27 Vol.2), p. 16.

[136] Tr. Vol. 22, 2654:6-10 (O'Laughlin).

[137] Tr. Vol. 22, 2652:26-2653:1 (O'Laughlin).

[138] Ex. 67 (PG&E-27 Vol.2), Figure 4, p. 15; p. 18, *citing* Ex. 169 (Overland), p. 3-8; Tr. Vol. 22, 2650:26-2651:1 (O'Laughlin).

[139] Ex. 67 (PG&E-27 Vol.2), p. 18; Tr. Vol. 22, 2659:5-22 (O'Laughlin).

[140] Ex. 67 (PG&E-27 Vol.2), p. 17, *citing* D.11-01-038, *Modesto Irrigation District, Merced Irrigation District v. PG&E*, Decision Approving Settlement Agreement, C.10-05-017 (January 27, 2011), *See* Tr. Vol. 22, 2654:14-2659:4 (O'Laughlin).

[141] *See* fn. 86 (-1). Resolution of "litigation risk" is not equivalent to endorsing a position. *See* D.11-01-038, pp. 4-5, 6 (Finding of Fact No. 4).

show huge declines in the years (2000, 2004, 2008) after the GRC decision in 1999 and GRC settlements in 1999, 2003, & 2007.[142] Such extreme levels of "negative attrition"[143] are simply not realistic, and if those results are "just math"[144] it represents a failure of the model utilized in the imputation. By comparison in the current proceeding PG&E is requesting a special post-test-year mechanism so that its capital expenditures in the out years would grow at a rate even higher than the typically-utilized inflation measures. The Commission should adopt Overland's imputation of capital expenditures.

Both Overland and PG&E found underspending (surplus revenues) in 2003-2007 expenses compared to adopted or imputed amounts for distribution, with overspending (negative revenues)in 2008-2010 expenses.[145] Underspending can lead to the necessity of later overspending, often in larger amounts than the prior underspending as problems fester and grow over time. DRA understands that SED is alleging in I.12-01-007 that in 2008-2010 there was serious underspending in transmission, the years prior to the San Bruno incident, with some of those costs being used instead to fund distribution, to make up for the prior distribution underspending. Both Overland and PG&E agreed that there were surplus revenues for the Gas Department (distribution and transmission) as a whole,[146] and surplus revenues for gas transmission, with Overland also concluding there were surplus revenues for distribution, and PG&E arguing there were negative revenues for distribution.[147] Even with those negative revenues compared to adopted or imputed amounts, in a period that covered recession years, PG&E claimed it earned a 10.71% return on equity on distribution from 2003-2010 compared to the authorized 11.30%.[148]

While Overland's analysis in this proceeding paralleled its analysis in I.12-01-007, the current rate proceeding is a forward-looking prediction for gas distribution operations in 2014,

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[142] Ex. 67 (PG&E-27 Vol. 2), p. 25, Figure 7; Tr. Vol. 22, 2661:3-2662:24 (O'Laughlin) (declines of 51% from 1999 to 2000, 46% from 2003 to 2004, 26% from 2007 to 2008).

[143] *See* Tr. Vol. 22, 2663:8-12 (O'Laughlin).

[144] Tr. Vol. 22, 2664:6 (O'Laughlin).

[145] Ex. 67 (PG&E-27 Vol. 2, p. 24, Figure 6.

[146] Tr. Vol. 22, 2667:22-27 (O'Laughlin); Ex. 67 (PG&E-27 Vol 2), p. 46, Figure 16, row [a].

[147] Ex. 67 (PG&E-27 Vol 2), p. 46, Figure 16.

[148] Ex. 67 (PG&E-27 Vol 2), p. 7, p. 45, Figure 15; Tr. Vol. 22, 2668:13-2669:3 (O'Laughlin).

not an investigation into PG&E's past practices. Overland's analysis generally supports the need to ensure that PG&E's spending on critical distribution areas such as pipeline replacement and DIMP not be diverted to other needs and be spent as directed, the concept motivating DRA's recommended balancing accounts in this proceeding.

Overland also analyzed PG&E's recordkeeping, and recommends the following improvements in PG&E's budget documentation:

- PG&E should document the basis for the initial budget targets set by management.
- Gas distribution should prepare an unconstrained budget request.
- Gas distribution should document the basis for its budget requests.
- PG&E's central budget committee should document the basis for its budget recommendation to management.
- Management should document the basis for the approved budget.
- Gas distribution should document the changes to its budget that occur during the budget year.[149]

PG&E maintains that "[g]as operations has already adopted a planning and budget process that reflects the principles underlying Overland's recommendations"[150] with "documentation … a key factor in those recommendations,"[151] although PG&E admits that it has not fully completed the long-term programs Overland proposed.[152] PG&E opposes adoption of Overland's budget recommendations,[153] but PG&E is not recommending to stop documenting its budget process, or the work in such programs.[154] PG&E witness Krannich later agreed that "the enhanced planning function and improved documentation of planning and budgeting decisions that you reference is functionally equivalent to the recommendations in the Overland Report."[155] DRA does not agree that PG&E's current processes are equivalent to the recommendations in the

[149] Ex. 169 (Overland), p. 8-19; Ex. 66 (PG&E-27 Vol 1), p. 3-1 and fn. 1; Tr. Vol. 15, 1529:23-1531:27 (Krannich).

[150] Ex. 66 (PG&E-27 Vol. 1), p. 3-2; Tr. Vol. 15, 1531:28-1532:6 (Krannich).

[151] Tr. Vol. 15, 1532:26-27 (Krannich).

[152] Ex. 66 (PG&E-27 Vol. 1), p. 3-8; Tr. Vol. 15, 1534:2-10 (Krannich).

[153] Ex. 66 (PG&E-27 Vol. 1), p. 3-8; Tr. Vol. 15, 1534:11-28 (Krannich).

[154] Tr. Vol. 15, 1533:16-22 (Krannich).

[155] Tr. Vol. 15, 1574:11-17 (Krannich); Ex. 169 (Overland), p. 8-19;

Overland Report, but regardless, DRA supports the Commission's formal adoption of those reporting recommendations in order to ensure that PG&E indeed meets the recommendations. PG&E claims it "will be in a position to report on the changes that we have made from a budget standpoint and how we spend money."[156] The Commission should hold PG&E to this claim.

2.2.5 Recommendations

The Commission should require PG&E to complete a risk assessment as soon as possible, in order to prioritize PG&E's safety efforts. The Commission should adopt DRA's proposed advice letter process for gas distribution capital spending, and DRA's capped, two-way DIMP balancing account. The Commission should reject PG&E's proposed uncapped, two-way balancing account for leak surveys. The Commission should adopt the recommendations of the SED consultants, including Overland's requirement of improved documentation of PG&E's budgeting process.

2.3 Audit, Reporting and Other Issues

2.3.1 DRA Results of Examination

As part of its analysis of PG&E's TY 2014 General Rate Case (GRC), DRA's Financial Examiners reviewed the recorded historical data PG&E used in connection with its revenue requirement forecast. DRA's findings are in its Results of Examination Report.[157]

Requested revenue requirements in general rate cases are usually based on test year forecasts which stem from recorded financial data. The general objective of DRA's Audit examination is an attempt to provide some level of reasonable assurance that the Applicant's financial data, on which forecasts may be built, is reliable and fairly stated pursuant to established Commission rules, regulations, and other relevant data.

DRA's examination of PG&E's financial records was conducted in accordance with the authority and mandates set forth in the Public Utilities Code Section 309.5. DRA's examination focused on PG&E's compliance with Commission-established rules and policies, and the ratemaking effects of PG&E's proposed revenue requirement. Given time and resource constraints, DRA's financial examination was not intended to address, and should not be

[156] Tr. Vol. 26, 3341:22-24 (Wells).

[157] Ex. 91 (DRA-23).

considered an endorsement of, the integrity of PG&E's spending decisions or accounting practices beyond what is specifically addressed in DRA's testimony.

Typically, DRA examiners make recorded financial data selections from selected areas of the utility's accounting books and records, perform analytical review, conduct witness interviews, review corporate minutes of Board of Director's meetings, review internal audit reports, and review external auditor's work papers. DRA's examiners did so in this case. DRA's Financial Examiners of PG&E's Operations and Maintenance Expenses, and Utility Plant made no recommendations separate from those of the DRA witnesses who reviewed the specific areas. The recommendations of DRA's subject matter experts for Operations and Maintenance expenses, and Utility Plant are set forth in Sections 3, 4 and 11 of this Opening Brief.

DRA's Financial Examiner for PG&E's Administrative and General Expenses examined the base year, 2011. Forecast methods often use the base year and, in many instances, the base year's balance is the highest recorded. Years where the balance is greater than the base year may indicate that items of a non-recurring nature contained within the recorded balance.[158] DRA's Financial Examiner for this GRC also reviewed additional years for transactional testing of specific Administrative and General expenses.

The following section is a discussion of individual audit procedures, and the adjustments DRA's Audit recommends.

2.3.1.1 Control and Compliance Assessments

DRA attempts to assess the financial controls over the recording of data to PG&E's records to ensure proper recording of data to PG&E's company-wide account categories. DRA is unaware of any material issues that call into question the proper recording of data to PG&Es general ledger.

Since PG&E compiles its data using Major Work Categories, rather than FERC-based accounts, DRA used PG&E's recorded data, as opposed to recorded/ adjusted data shown in PGE's testimony. DRA made 4,633 transactional testing selections and met with PG&E subject matter experts, asking them to provide a description of the goods or services and explain why the cost was considered recurring for ratemaking purposes. DRA then took a sample of the invoices

[158] Ex. 91 (DRA-23), p. 4.

to attempt to determine whether PG&E had removed all costs related to the September 2010 San Bruno disaster from the recorded/ adjusted data PG&E presented in testimony. Below are the results of DRA's Audit of Administrative and General expenses.

2.3.1.2 FERC Account 925 – General Liability

During the course of its review, DRA noted that PG&E's general liability insurance increased $11.1 million from 2010 to 2011. DRA asked PG&E for an explanation of this increase and was told:

> The increase in general liability insurance from 2010 to 2011 is based on insurance industry concerns about the age of infrastructure in the U.S., in general, and in California, in particular. In addition, significant losses for the insurance industry affect excess liability premiums. This includes costs of the San Bruno accident as well as other losses worldwide.[159]

DRA then asked PG&E for all documentation and/ or correspondence that showed the previous costs for this type of insurance (2010) and the new costs (2011) were due to "aging infrastructure in California" and "losses in the insurance industry."[160] PG&E's response was:

> PG&E's insurance providers do not specify in their quotes what drives increases or decreases to premiums. PG&E's response regarding the drivers of the increase is based on the Company's and its broker's experience and knowledge of the insurance market. PG&E has included reference materials that discuss this topic in its workpapers.[161]

Since this response provided no information specific to PG&E's general liability insurance increases, DRA asked for "all evidence, information and documentation" PG&E relied on for its generalizations. PG&E's response was to cite back to its earlier generalizations and workpapers.[162]

Thus, PG&E's rationale for including this significant expense increase seems to be based on two articles from insurance brokers, but no information specific to PG&E's operations. It seems extremely unlikely to DRA that the insurance industry would ignore the San Bruno

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[159] Ex. 93 (DRA-23), p. 5, footnote 1 citing PG&E's response to DRA-PG&E-LMW-006, Q.3.l.

[160] Ex. 93 (DRA-23), p. 5.

[161] Ex. 93 (DRA-23), p. 5, footnote 1 citing PG&E's response to DRA-PG&E-LMW-012, Q.2c.

[162] Ex. 93 (DRA-23), p. 6, footnote 5, citing PG&E's response to DRA-PG&E-LMW-015, Q.1.

disaster when considering rates for PG&E in particular, or California in general. Surely, the insurance industry takes into account such a widely known and horrific event as San Bruno when setting insurance premiums.

Even PG&E's workpapers evidence this tenet:

> LOSSES DRAW SCRUTINY
>
> 'Losses in the energy sector, particularly with respect to oil and gas pipelines – transmission or distribution of gas as well as petroleum-- have drawn the attention of underwriters. Insurers are generally looking for increased premium rates for insureds that engage in such operations ***especially those that have presented losses to insurers.***"[163]

The San Bruno disaster in September 2010, and the claims surrounding it, seem to fit well within the description of "losses to insurers" that have drawn the attention of underwriters. The evidence and timing of the insurance increase strongly suggest that the San Bruno incident is a major contributor to the ensuing general liability insurance increase.

DRA did look beyond the San Bruno disaster to whether there were other related and/or unrelated factors that might account for the increase in insurance premiums. For example, PG&E's corporate behavior may have also been a risk factor. PG&E's actions are noted in the following January 2012 article from the San Francisco Chronicle:

> **PG&E diverted safety money for profit, bonuses**
>
> **Reports: Utility diverted safety funds into profit**
>
> Eric Nalder, Chronicle Staff Writer
>
> Published 4:00 am, Friday, January 13, 2012
>
> "Pacific Gas and Electric Co. diverted more than $100 million in gas safety and operations money collected from customers over a 15-year period and spent it for other purposes, including profit for stockholders and bonuses for executives, according to a pair of state-ordered reports released Thursday.
>
> An independent audit and a staff report issued by the California Public Utilities Commission depicted a poorly led company well-heeled in its gas operations and more concerned with profit than safety.

[163] Ex. 93 (DRA-23), p. 7, citing Ex. 39, (PG&E-9 workpapers), p. WP 3-167, emphasis added.

The documents link a deficient PG&E safety culture - with its "focus on financial performance" - to the pipeline explosion in San Bruno on Sept. 9, 2010, that killed eight people and destroyed 38 homes.

The "low priority" the company gave to pipeline safety during the three years leading up to the San Bruno blast was "well outside industry practice - even during times of corporate austerity programs," said the audit by Overland Consulting of Leawood, Kan.

Making money

But PG&E wasn't hurting for cash, according to the audit. From 1999 to 2010, the company collected $430 million more from its gas-transmission and -storage operations than the revenue authorized by the California Public Utilities Commission, which sets the rates the company can charge its customers.

"PG&E chose to use the surplus revenues for general corporate purposes" rather than improved gas safety, the Overland audit said.

The audit was unable to trace exactly how PG&E spent the diverted money. But in a separate report on the San Bruno explosion released Thursday, the utilities commission staff noted that in the three years leading up to the San Bruno explosion, the company spent $56 million annually on an incentive plan for executives and "non-employee directors," including stock awards, performance shares and deferred compensation.

"A cursory review reveals that a significant portion, in the millions, has been awarded to the CEO," the commission staff report said in a reference to former PG&E head Peter Darbee, who retired last year.

Cutting corners

By cutting back on pipeline-replacement projects and maintenance, laying off workers, using cheaper but less effective inspection techniques and trimming other pipeline costs, PG&E saved upward of 6 percent of the money designated for pipeline safety, maintenance and operations programs, the Overland audit said.

Meanwhile, on the revenue side, transmission pipeline operations were "very profitable" for PG&E since March 1998, the audit said.

Assemblyman Jerry Hill, D-San Mateo, whose district includes San Bruno, called the company's diversion of customers' money "criminal behavior."

"When you divert funds intended for maintenance and safety to profits, there is nothing clearer," Hill said. "It is criminal."

Hill noted that the San Mateo County district attorney, the state attorney general and the U.S. attorney's office are conducting a joint investigation of the San Bruno disaster. He said he would talk to them about incorporating the Overland audit in their probe.

However, it is unclear whether PG&E broke any criminal statutes governing its behavior at the time, unless there was fraud.

The utilities commission staff report said that under state law and agency regulations, PG&E could spend less than what it was authorized to spend "because the commission is generally precluded from asking for the money back if the company overestimated its revenue requirement."

The Legislature passed a law last year, sponsored by Hill and others, that requires a utility to account for any under-spending and explain where every dollar went.

'Truly unconscionable'

"It is truly unconscionable that PG&E was allowed by the CPUC to steal ratepayer monies that should have been spent on safety and, instead, was put in the pockets of PG&E shareholders," said Rep. Jackie Speier, D-Hillsborough, who represents the devastated San Bruno neighborhood. "All these monies identified in the audit should be returned to ratepayers, presumably as a credit against the work that PG&E should have done, but didn't."

PG&E officials declined to comment on specifics of the two reports.

"Our No. 1 priority is to make our system the safest in the nation," said PG&E President Chris Johns.

No new money

The utilities commission issued the documents as part of a process that could lead to millions of dollars in fines. In addition, the commission recommended changes in how PG&E spends money on gas-system maintenance and pipeline replacement.

Before PG&E "seeks additional ratepayer funds," the commission said, it should:

-- Allocate $95.4 million that the company under-spent on capital expenditures since 1997 - including pipeline replacement - for those purposes.

-- Use the $430 million in additional revenue it collected since 1999 "to fund future transmission and storage operations."

-- Use $39.3 million that it collected but failed to spend for pipeline-transmission operations and maintenance since 1997 for those purposes.

Those recommendations put the commission and PG&E on a collision course.

In August, PG&E outlined a plan to modernize its gas-transmission lines in response to the San Bruno disaster. Included was money to replace 185 miles of pipe segments in PG&E's 5,700-mile gas-transmission system and to upgrade 200 miles of other segments unable to accommodate a modern inspection tool known as a "smart pig."

The company pegged the price at $2.2 billion and said 90 percent of that would be paid by gas customers through rate increases, with the rest covered by company investors.

Meeting new rules?

On Wednesday, PG&E issued a statement promising that it won't dun customers for any expense required to upgrade its gas system to meet existing federal and state standards.

"That said, let's be just as clear about what PG&E is proposing," the company added. "The vast majority of the pipeline safety work going forward is not about correcting issues from the past. It's about meeting entirely new standards being established by the California Public Utilities Commission."

PG&E estimated that the average residential customer will pay $1.93 per month more through 2014 to finance the work.

A Chronicle investigation published in March revealed that in 2000, PG&E sharply curtailed a program started in the mid-1980s to replace hundreds of miles of aging gas-transmission pipe. Records obtained by The Chronicle showed the decision was made by PG&E and approved by the utilities commission's safety chief.

The Overland audit noted that PG&E's replacement of transmission pipelines for safety purposes all but ceased in 2000."

Obviously, since this article is now more than a year and a half old, other facts may come to light to offer other viewpoints. But, for purposes of this GRC, it is PG&E's burden to show that the increase in insurance rates was not due to San Bruno; and/ or that PG&E's corporate behavior was not responsible for the increase in insurance premiums.

PG&E's showing fails to address either issue. In the absence of any proof to the contrary, DRA's Audit recommends that the Commission reduce the 2011 FERC Account 925 by $11.1million.[164]

2.3.1.3 MWC IF -- Electric Emergency Recovery

As part of its Audit, DRA reviewed PG&E's Major Work Category (MCW) IF, Electric Emergency Recovery. DRA found that PG&E did not reduce its Electric Emergency Recovery for expenses requested for recovery in Catastrophic Event Memorandum Account (CEMA) Application A.11-09-014. PG&E said it was waiting for a final decision on the case to make any adjustment. The Commission issued its decision in June 2016.[165]

An adjustment is appropriate for expenses for which PG&E will receive recovery outside the GRC process. The Commission adopted the all-party settlement agreement reached in A.11-09-014. That settlement includes a CEMA related expense recovery of $17.844 million.[166] For purposes of simplicity, and to avoid a convoluted estimation process, DRA recommends the entire expense recovery amount be applied to 2011 given that 2011 represents a majority of the costs in MWC IF. Considering this evidence, DRA recommends that the Commission reduce MWC IF by $17.844 million for 2011.[167]

2.3.1.4 FERC Account 923 – Outside Services Employed

In DRA's testimony in the TY 2012 GRC of Southern California Edison Company (SCE), DRA recommended that the Commission deny ratepayer recovery of the costs for tax consultants. DRA based its recommendation on the "static, formulaic" way in which taxes are determined for ratemaking purposes.[168] The Commission decision in that SCE GRC includes the following:

> DRA argues most tax consulting services are non-recurring and primarily benefit shareholders because tax expense for ratemaking is static and consulting expertise is more relevant to the complicated aspects of post-GRC taxation reflected in the

[164] Ex. 91 (DRA-23), p. 11.

[165] D.13-06-007, 2013 Cal. PUC LEXIS 327.

[166] D.13-07-007, 2013 Cal PUC LEXIS 327 *11.

[167] Ex. 91 (DRA-23), p. 11.

[168] Ex. 91 (DRA-23), p. 12.

> fluctuating effective rates found at the utility and holding company level. In addition, states DRA, work arising from audits or avoided penalties and interest relate to tax returns, not the tax expense forecast for ratemaking. If an audit results in a lower tax rate, then SCE can offset costs rather than forecast what may be non-recurring costs. Finally, DRA asserts that SCE's in-house tax staff should be able to handle routine tax matters such as historic deductions and forecasting for ratemaking.
>
> …
>
> The Tax Department's functions (tax modeling, legal research, following changes in tax law, return filing, audit defense, etc.) are essential to the company's compliance with existing tax laws. However, SCE did not adequately explain the trend of substantial increases in Outside Services (28% in 2009) when many activities are routine and its own tax professionals, both lawyers and accountants, have a duty to keep current with applicable laws and ratepayers fund continuing education.
>
> Although Account 923 historic costs have trended upward since 2006, we are persuaded that tax-related outside services are included which primarily benefit shareholders of SCE and EIX by lowering effective rates below the rates used for forecasting purposes. Thus, SCE's forecast is excessive and should be reduced to exclude "as-needed" non-recurring and effective tax rate consulting costs.[169]

To find out if the charges of PG&E's tax consultants were similar to those of SCE, DRA asked PG&E for documentation, including invoices, that all of PG&E's recorded tax consulting expenses for the years 2007 to 2011 benefited ratepayers.[170]

Based on the information PG&E provided, DRA assumed for purposes of this GRC that PG&E's 2011 tax consulting costs benefitted ratepayers. However, other information PG&E provided DRA's Financial Examiner shows benefits to PG&E's shareholders, not PG&E's ratepayers. If the Commission intends to treat the tax consulting cost issue in this PG&E GRC the way it treated tax consulting costs in SCE's last GRC, then DRA's Financial Examiner recommends that the Commission remove the amounts of $0.867 million for 2010, $1.026 million for 2009, $2.011 M for 2008, and $2.278 million for 2007.[171]

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[169] D.12-11-051, mimeo, p. 480-481.

[170] Ex. 91 (DRA 23), p. 13.

[171] Ex. 91 (DRA-23), p. 14.

2.3.1.5 Board of Directors Costs

DRA's Financial Examiners reviewed PG&E's Board of Directors Minutes from 2009 to 2011. During the course of this review, DRA noted several pages of redacted information. In order to perform a full review that allows a complete assessment of whether any information will yield an adjustment, DRA asked that the redacted portions be provided. PG&E invoked the attorney client privilege.[172] DRA does not challenge PG&E's claim of attorney client privilege, but asserts that PG&E failed to meet its burden of proof.

In the Commission's decision in the SCE TY 2009 GRC, the Commission removed costs where Edison invoked the attorney client privilege. This was not a judgment on Edison's claim of attorney client privilege. Instead, as the Commission noted:

> DRA reviewed internal audits conducted from 2003 through August 2007 by SCE's Audit Services Department (ASD). In the course of this review, SCE asserted attorney-client privilege and on that basis refused to allow DRA to review 36 audits. DRA does not challenge SCE's assertion of attorney-client privilege. However, DRA could not determine the reasonableness of these audits for ratemaking purposes. For this reason, DRA concludes that SCE's showing is deficient and recommends disallowance of $1.996 million (25%) of 2006 recorded audit costs. In 2006, SCE completed 160 audits and DRA requested to review 12 reports designated as privileged. SCE later determined that only 11 privileged audit reports existed for 2006.
>
> SCE asserts it has provided DRA with access to over 90% of the audit reports. SCE argues it has "satisfied its burden of proof by making all of its non-privileged audit reports, representing more than 90% of its audits, available for review by DRA."
>
> Since DRA does not challenge SCE's assertion of attorney-client privilege, the Commission need not address the reasonableness of the assertion. Thus, the issue is whether SCE has met its burden of proof. Since SCE chose to assert its claim of attorney-client privilege, it must meet its burden of proof in some other way. SCE argues that it met its burden of proof by giving DRA access to over 90% of the audits.
>
> If, out of all the audits, 90% were randomly picked and reviewed, and if the review found that the randomly picked audits were reasonable, one could reasonably infer that the remaining 10% of

[172] Ex. 91 (DRA-23), p. 14.

> the audits were reasonable. However, since the audits SCE chose to withhold from review were not randomly picked, the results of the review of the non-privileged audits cannot reasonably be applied to the withheld audits. Thus, SCE's provision of over 90% of the audits to DRA does not mean that the costs of the remaining privileged audits are reasonable. Therefore, SCE has not demonstrated that its privileged audits are reasonable for ratemaking purposes. For this reason, the costs of the privileged audits will be disallowed for 2006.
>
> DRA proposes a reduction of 25% of the 2006 audit costs. However, 159 audits were conducted in 2006, of which 11 (6.9%) were privileged. Therefore, a reasonable disallowance for 2006 would be 6.9% of such costs.[173]

The same reasoning should be applied here. PG&E is unquestionably entitled to claim attorney client privilege for portions of the Minutes of its Board of Directors. But there is no reason to assume that the redacted information would necessarily reference costs that can reasonably be charged to ratepayers. Therefore, DRA recommends that the Commission remove 2011 Board of Director costs of $1.566 million, 2010 costs of $1.322 million, and 2009 costs of $0.990 million.

2.3.1.6 Internal Audit Report Cost Removal

DRA's Financial Examiners reviewed PG&E's Internal Audit Reports. DRA was denied review of three of these reports based on the claim by PG&E of attorney client privilege. DRA does not challenge PG&E's claim of attorney client privilege, but asserts PG&E failed to meet its burden of proof. For the same reasons as noted above in connection with Board of Directors Meeting Minutes, DRA recommends that the Commission remove $78,000 in 2011 internal audit report costs for the reports that were not provided.

2.3.2 Continuation of Reporting Requirements Adopted in the 2011 GRC

DRA recommends that all reporting requirements adopted in the 2011 GRC be continued.

2.3.3 Other Issues

DRA has no other issues to address at this time.

[173] D.09-03-025, mimeo, pp. 316-318; 2009 Cal. PUC LEXIS 165.

3 GAS DISTRIBUTION

3.1 Policy and Introduction

DRA recommends a 2014 gas distribution expense forecast of $275.0 million, a $42.5 million or 18% increase over PG&E's 2011 recorded expenses of $232.5 million.[174] DRA's proposed DIMP balancing account allows PG&E the opportunity to recover up to $13.6 million in additional expenses.[175] PG&E has requested $465 million,[176] a 100% increase over its 2011 recorded expenses. According to PG&E, the primary drivers for the increase from 2011 to 2014 are:

1. Corrective maintenance, principally leak repair costs ($65 million increase);
2. Field services and dispatch increases due to increased emergency response goals ($37 million increase);
3. Distribution integrity management ($23 million increase);
4. Technology expenses ($19 million increase).[177]

DRA recommends a 2014 gas capital expense forecast of $482.4 million, a $174.5 million or 56.7% increase over PG&E's 2011 recorded capital expenditures of $307.9 million.[178] PG&E has requested $831.3 million, a 170% increase over its 2011 recorded capital expenditures of $307.9 million.[179] DRA's proposed advice letter process for gas capital safety expenditures in MWC 14 and 50 allows PG&E the opportunity to recover up to $171.1 million in additional capital expenditures.[180]

In Section 2.2.3 and subsections 2.2.3.1 and 2.2.3.2 above, DRA discussed balancing safety with just and reasonable rates, which, while applicable to all of PG&E's operations, is primarily focused on gas distribution. PG&E's application is devoid of any recognition that its

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[174] Ex. 321 (DRA-9-E), p. 3; Ex. 77 (DRA-9), p. 3; Ex. 53 (PG&E-18 Vol. 1), p. 1-7, Figure 1-1.

[175] Ex. 53 (PG&E-18 Vol. 1), p. 1-7, Figure 1-1.

[176] Ex. 77 (DRA-9), p. 3.

[177] Ex. 77 (DRA-9), p. 3, *citing* Ex. 14 (PG&E-3), p. 1-39.

[178] Ex. 314 (DRA-10-E), p. 1; Ex. 53 (PG&E-18 Vol. 1), p. 1-8, Figure 1-2.

[179] Ex. 53 (PG&E-18 Vol. 1), p. 1-8, Figure 1-2; Tr. Vol. 13, 1139:25-1140:1 (Stavropoulos).

[180] Ex. 53 (PG&E-18 Vol. 1), p. 1-8, Figure 1-2. Tr. Vol. 13, 1138:8-13 (Stavropoulos).

requested increases are extraordinarily large, a doubling of expenses and almost a tripling of capital expenditures in only three years, and those 2011 recorded expenses were for the first year after San Bruno. Moreover, despite PG&E's behavior in administering its gas transmission and distribution systems, as detailed in the Overland Report and the investigation into the gas transmission system, I.12-01-007, PG&E requests traditional ratemaking treatment for almost all of its expenses and all of its capital expenditures allowing it full discretion to spend costs as it see fits, including on non-gas operations. The one exception is gas leak detection, for which PG&E requests [a 71% increase over 2011 spending[181] and an uncapped, two-way balancing account allowing an even higher increase.

The Commission must still approve rates that are "just and reasonable" even with increased emphasis on safety. In the absence of the requested risk assessments, the numerous areas where PG&E's estimates of spending for 2012 and 2013 to date were too high, and the lack of specific details even now for spending next year, the Commission must be cautious in evaluating PG&E's requested cost increase. This is particularly true for capital spending in MWCs 14 and 50, for which PG&E has proposed a total of $469.2 million in 2014, which would represent an almost 50% increase over all capital spending for all fourteen MWCs for 2011.[182]

3.2 System Operations and Distribution Control

3.2.1 Expense

PG&E proposed $20.0 million in expenses in this area, $13.9 million for MWC FG and $6.1 million for MWC GG. DRA recommends $14.0 million, $8.3 million for MWC FG and $5.7 million for MWC GG.[183] DRA's recommendation is $3.3 million above PG&E's 2012 recorded expenses.[184]

PG&E proposes to hire 25 Full Time Employees (FTEs) for its Distribution Control Center. PG&E explicitly planned the Distribution Control Center to function similarly to its existing transmission Gas Control Center.[185] PG&E initially represented in a data response dated

[181] Ex. 14 (PG&E-3), p. 6-21.

[182] *See* Ex. 78 (DRA-10), p. 3, Table 10-1.

[183] Ex. 321 (DRA-9-E), p. 6, Table 9-3

[184] Ex. 321 (DRA-9-E), p. 6.

[185] Ex. 77 (DRA-9), p. 10, *citing* Ex. 14 (PG&E-3), p. 2-7.

October 23, 2012, that the Gas Transmission Center, which operates 24 hours, requires four to six people depending on the workload:

For the day shift in the Gas Transmission Center, there are two operators and one senior coordinator and for the night shift, there is one operator and one senior coordinator.[186]

DRA thus testified that "PG&E needs 5 FTEs for each 24 hour shift (two 12-hour shifts), to operate the Gas Transmission Center."[187] PG&E further noted in this data response that there are three consoles to operate the gas transmission system, and six consoles to operate the gas distribution system.[188] PG&E also stated that in this data response that in the gas distribution control center, "the total number of employees can increase from seven to nine,"[189] and DRA testified that there are "a total of 9 FTEs on average for each 24-hour shift."[190] Based on this information, DRA initially recommended 11 FTEs for 2014, based on 9 FTEs for the distribution control center – approximately two times the 5 FTEs for the transmission center – one relief operator, and one relief coordinator.[191]

However, on July 16, 2013, only hours prior to the scheduled cross-examination of PG&E witness Melvin Christopher, PG&E modified its data response of October 22, 2012, to say the following:

> For the day shift in the Gas Transmission Center, there are three operators one senior coordinator, and two transmission coordinators, and for the night shift, there are two operators, one senior coordinator, and one transmission coordinator.[192]

Thus, PG&E actually needed 10 FTEs for each 24-hour shift, six during the day and four at night,[193] to operate its Gas Transmission Center, rather than the 5 FTEs DRA initially

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[186] Ex. 98 (DRA-9-WP), PG&E Response to DRA-022 Question 6, p.1 ; Ex. 77 (DRA-9), p. 10.

[187] Ex. 77 (DRA-9), p. 10.

[188] Ex. 98 (DRA-9-WP), PG&E Response to DRA-022 Question 6, p. 1.

[189] Ex. 98 (DRA-9-WP), PG&E Response to DRA-022 Question 6, p. 2.

[190] Ex. 77 (DRA-9), p. 11.

[191] Ex. 77 (DRA-9), p. 12.

[192] Tr. Vol. 14, 1248:8-23 (Christopher); *see* Ex. 98 (DRA-9-WP), PG&E Response to DRA-022 Question 6, p.1.

[193] Tr. Vol. 14, 1248:21-23 (Christopher).

assumed. DRA thus revised its recommendation from 11 FTEs to 21 FTEs,[194] to reflect the additional 5 FTEs used to operate the Gas Transmission Center on a 24-hour basis[195] on three consoles, extrapolated to an additional 10 FTEs to operate the Gas Distribution Center on a 24-hour basis on six consoles, twice as many consoles as in the Transmission Center. DRA also recommends a credit of $500,000 based on savings in the Transmission Center created by the Distribution Center.[196] On rebuttal, PG&E concedes this was approximately the cost of the work, but claims that it is accounted for because PG&E in this GRC did not forecast such transmission costs, as it had in past GRCs.[197] But PG&E provides no explanation as to why such transmission costs were included in past distribution GRCs, nor denies that there will be savings to transmission. Without any proof that such costs were properly included in the past GRCs, the Commission should PG&E's explanation that it has already accounted for these savings.

DRA recommends that PG&E's request for 5 FTEs for PG&E's new Clearance Personnel function be denied. PG&E's application failed to provide any detailed explanation, supporting analysis or conclusions on how it determined the 5 FTEs.[198] DRA noted that reviewing, approving and coordinating planned clearances, and coordinating notifications for work affecting distribution facilities, are activities that PG&E should be doing (and has been doing) without the new Gas Distribution Control Center.[199]

PG&E's rebuttal testimony misrepresented DRA's primary argument, only addressing DRA's supporting point that PG&E failed to support its claim that one clearance coordinator was needed for each of its four Maintenance and Construction by reiterating that "[t]o staff this function, four clearance coordinators are required, one per region"[200] without any further analysis. PG&E claims centralizing the clearance function "is an emerging approach in the gas

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[194] Ex. 321 (DRA-9-E), p. 12.

[195] *See* Tr Vol. 26, 3806:15-26.

[196] Ex. 77 (DRA-9), p. 12 and fn. 22, *citing* Ex. 98 (DRA-9-WP), PG&E response to DRA-22, question and Ex. 15 (PG&E-3 WP 02-06), p. WP-2-17, line 16.

[197] Ex. 53 (PG&E-18 Vol. 1), p. 2-20.

[198] Ex. 77 (DRA-9), p. 13 and fns. 26-28, *citing* Ex. 98 (DRA-9-WP), PG&E Response to DRA-22. question 7.

[199] Ex. 77 (DRA-9), p. 13.

[200] Ex. 53 (PG&E-18 Vol. 1), p. 2-16.

distribution industry"[201] but such a statement admits that the function has been decentralized and funded in the past elsewhere than the Gas Control center.

DRA recommends that PG&E's request for 4 FTEs for PG&E's Gas Control and System Operations Support function be denied. PG&E again failed to provide a detailed explanation of the number of FTEs, merely listing four positions and their proposed functions without support.[202] Again on rebuttal, PG&E continues to just list the four positions and their proposed functions.[203]

DRA recommends that PG&E's request for 3 FTEs for Department and Project Management be denied, as when DRA requested support for PG&E's request, PG&E again failed to provide a detailed explanation of the number of FTEs.[204] On rebuttal, PG&E remarkably claims the need for these positions is "self-evident."[205] This attitude is prevalent throughout PG&E's filing, and underscores how little support PG&E provides and believes is needed to justify its request, and the lack of any risk assessment underlying PG&E's application. DRA disagrees that a mere description of a function and a proposed list of employees meets PG&E's burden in this proceeding.

DRA recommends that PG&E's request for 9 FTEs for Gas Control Technology Support Personnel be reduced by two-thirds to 3 FTEs, based on PG&E's failure to provide sufficient support for how they determined that 9 was the reasonable number of personnel, and PG&E's hiring of only 1.3 FTEs in 2002 when they forecast they would hire 4 FTEs.[206] On rebuttal, PG&E claims it "produced a workpaper that provides further data,"[207] but line 20 of that workpaper listing the 9 FTEs references a "Note 2" that on line 43 merely states, "[i]n support of these new technologies, the Gas Technology Support personnel headcount *is expected to*

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[201] Ex. 53 (PG&E-18 Vol. 1), p. 2-16.

[202] Ex. 77 (DRA-9) p. 14 and fns. 29-31, *citing* Ex. 98 (DRA-9-WP), PG&E Response to DRA-22, question 7.

[203] Ex. 53 (PG&E-18 Vol. 1), p. 2-17.

[204] Ex. 77 (DRA-9) pp. 14-15 and fn. 32, *citing* Ex. 98 (DRA-9-WP), PG&E Response to DRA-22, question 7.

[205] Ex. 53 (PG&E-18 Vol. 1), p. 2-18.

[206] Ex. 77 (DRA-9) pp. 15-16 and fns. 33-38, *citing* Ex. 98 (DRA-9-WP), PG&E Response to DRA-22, question 6, and Ex. 15 (PG&E-3 WP 02-06), p.WP 2-28.

[207] Ex. 53 (PG&E-18 Vol 1), p. 2-17, *citing* Ex. 15 (PG&E-3 WP 02-06), p.WP 2-28.

increase by 9 employees."[208] This statement is woefully insufficient for PG&E to carry its burden of proof.

DRA recommended that PG&E's proposed $1.7 million of spending for maintenance due to Remote Terminal Units, flow meters and pressure recorders be reduced to $825,000, and PG&E "concedes to the removal of $875,000."[209]

3.2.2 Capital Expenditures

In connection with its new Gas Distribution Control Center, PG&E proposes to spend $62.2 million to cover the capital costs regarding the installation of devices to remotely monitor and control the gas distribution network.[210] Such remote terminal units transmit data on a real-time or recorded basis.[211] PG&E noted that "the installation of these devices on existing underground facilities presents significant permitting and system operation issues, which is the primary reason that the control center build-out will take several years."[212] PG&E's forecast of gas monitor control units in 2012-2014 shows a rapid ramp-up in spending on four different types of RMUs.[213] For 2014, PG&E forecasted $62.2 million in capital costs in MWC-4A, $24.9 million in 2013, and $4.4 million in 2012.[214] PG&E's 2012 spending was only $2.4 million.[215] Generally, the amounts of devices that PG&E forecasted have no support other than PG&E's recommendation. Based on delays in installations to date, excessive forecasts for 2012 and 2013, and the uncertain status of resolving the issues regarding installation, DRA recommended that the Commission adopt the 2013 forecast of $24.9 million as the 2014 amount.

PG&E forecasted the installation of 12 Electric Pressure Recorders that monitor pressure at regulations stations in 2012, 203 in 2013 and 378 in 2014, but failed to install any devices in

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[208] Ex. 15 (PG&E-3 WP 02-06), p.WP 2-28, lines 20, 43 (emphasis added). The cross-references on Line 13 to WP 2-42 and 2-18 line 29 yield no further support either.

[209] Ex. 53 (PG&E-18 Vol 1), p. 2-20.

[210] Ex. 78 (DRA-10), p. 8; *see also* Ex. 14 (PG&E-3), p. 2-21; Tr. Vol 14, 1213:21-1214:10.

[211] Ex. 14 (PG&E-3), p. 2-21; Tr. Vol 14, 1214:11-20.

[212] Ex. 14 (PG&E-3), p. 2-21; Tr. Vol 14, 1214:21-1215:1.

[213] Ex. 78 (DRA-10), p. 11, Table 10-5, *citing* Ex. 15 (PG&E WP Vol. 2-6), pp. WP 2-40 to 2-41.

[214] Ex. 78 (DRA-10), pp. 7 – 8 and Table 10-3.

[215] Ex. 78 (DRA-10), p. 8.

2012.[216] PG&E's response as to how it chose 378 as the forecast for 2014 noted "there were 2130 locations identified for monitoring of pressure with RTU devices"[217] and that "the installation of these units was spread over years based on resource allocations."[218] Although PG&E initially estimated it would install 203 locations in 2013 as well as the 12 not performed in 2012,[219] and did not say otherwise in rebuttal testimony, under cross-examination PG&E witness Christopher admitted that the plans had been changed substantially:

> And as a result of that assessment, that quantitative assessment and a result of further review with our DIMP team, we made a very important decision not to pursue 203 units here, rather to pursue 30 of these units in 2013 and to use a different technology and install 86 of a different type of technology which provides more data in real time.[220]

Mr. Christopher elsewhere admitted that he was "unaware" of how many devices of the 203 forecasted for 2013 were installed in 2013 to date.[221] Based on the admitted changes in the scope of this program to a "different type of technology," PG&E cannot maintain that its forecast of 378 installations in 2014 is reasonable. PG&E has no support for its claim that this will increase costs over the initial forecast,[222] as it is unclear at all what devices let alone how many PG&E is forecasting to install in 2014 for this function, and PG&E needs to identify sites and prepare site-specific designs.

PG&E forecasted to install 130 portable Electronic Pressure Recorders at Hydraulically Independent System (HIS) low points, Critical non-core customers and some non-HIS systems in 2012, 500 in 2013 and 500 in 2014, but only installed two devices in 2012.[223] PG&E plans to

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[216] Ex. 78 (DRA-10), p. 11, Table 10-5, *citing* Ex. 15 (PG&E-3-WP Vol 2- 6), WP 2-40 to WP 2-41; Ex. 99 (DRA-10-WP), pp. 145 – 148, PG&E Response to DRA-81, question 4; Tr. Vol. 13, 1223:8-13.

[217] Ex. 99 (DRA-10-WP), pp. 145-147, PG&E Response to DRA-81, question 4(f) & 4(g)

[218] *Id.*

[219] Ex. 99 (DRA-10-WP), pp.145-147, PG&E Response to DRA-81, question 4(d).

[220] Tr. Vol. 13, 1230:14-22 (Christopher).

[221] Tr. Vol. 13, 1229:20-27 (Christopher).

[222] Tr Vol. 13, Tr. 1231:8-14.

[223] Ex. 78 (DRA-10), pp. 11-12 and Table 10-5, *citing* Ex. 15 (PG&E-3-WP Vol 2- 6), WP 2-40 to WP 2-41; Ex. 99 (DRA-10-WP), pp. 149 – 151, PG&E Response to DRA-81, question 5; Tr. Vol. 13, 1218:21-1219:10 (Christopher).

schedule the 2012 deferred installations for 2013.[224] PG&E determined the 500 number based on identifying 2130 total locations for such pressure devices, based on a series of estimates regarding locations per HIS, number of critical non-core customers needing monitoring, number of HIS supplying 500 more customers, estimates of non-HIS systems, and then dividing the 2130 by four years "based on resource availability."[225] However, on cross-examination Mr. Christopher claimed PG&E could do "20 to 30 per week" and they had the resources in the rest of the year to do as much as "750, 800 this year"[226] even though to date in 2013 they have still only done 53 and have only 160 signed consent forms with customers.[227] DRA's recommendation that PG&E's 2013 forecast be used for 2014 does not affect funding for this type of RTU, because PG&E forecasted 500 for both 2013 and 2014, but DRA's concerns that PG&E's 2014 forecasts are not adequately supported remains for this function.

PG&E had forecasted to install five gas control monitoring and control devices of pressure and flow at regulation stations, control of regulator set points and control of five valves in 2012, 67 in 2013, and 127 in 2014, but PG&E did not install any in 2012.[228] These devices require the use of Supervisory Control and Data Acquisition (SCADA) technology.[229] PG&E determined the five, 67 and 127 figures by estimating a total of 510 locations and devices at these locations, and stating that the "installation of these units was spread over several years based on resource availability, resulting in 67 scheduled for 2013 and 5 units delayed in 2012, all of these units scheduled for 2013"[230] and "resulting in 127 scheduled for 2014."[231] PG&E delayed the 5 units scheduled for 2012 due to its conclusion that "the technology may not be

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[224] Ex. 78 (DRA-10), p. 12, *citing* Ex. 99 (DRA-10-WP), pp. 149 – 151, PG&E Response to DRA-81, question 5; Tr. Vol. 13, 1219:10-12 (Christopher).

[225] Ex. 99 (DRA-10-WP), pp. 149 – 151, PG&E Response to DRA-81, question 5; Tr. Vol. 13, 1219:15-24 (Christopher).

[226] Tr. Vol. 13, 1221:2 – 1222:2 (Christopher). *Cf.* Tr. Vol. 13, 1223:14-16 (Christopher) ("we will install probably 600 by the end of the year.")

[227] Tr. Vol. 13, 1223:12-20 (Christopher).

[228] Ex. 78 (DRA-10), pp. 11-12 and Table 10-5, *citing* Ex. 15 (PG&E-3-WP Vol 2- 6), WP 2-40 to WP 2-41; Ex. 99 (DRA-10-WP), pp. 152 – 154, PG&E Response to DRA-81, question 6; Tr. Vol. 13, 1218:21-1219:10 (Christopher).

[229] Tr. Vol. 13, 1224:3-23 (Christopher).

[230] Ex. 99 (DRA-10-WP), pp. 152-154, PG&E Response to DRA-81, question 6.

[231] *Id.*

appropriate for low pressure stations."[232] Under cross-examination, when asked about the status of resolving this technological issue, Mr. Christopher stated that

> So we are now moving forward with installations but we are not installing that technology, the regulator. And we will be able to come back at a later time and put in the proper regulator. But we're beginning construction work on these devices now. We have the designs completed and we are continuing to look for the best solution for the low pressure regulator.[233]

PG&E has installed only two of these devices to date in 2013, and claims it has four more that are "construction-ready," 16 in the final approval stage, and 30 in "engineering design."[234] While PG&E does claim that it has determined the locations for 2014 deployment, consistent with its representation that it would do so in the first quarter of 2013,[235] PG&E had stated in its response to DRA-81, question 6(h) that the "schedule for the 2014 deployment will be developed after the locations are identified per question 4.h above."[236] DRA-81, question 4(h) asked about the locations of the Electronic Pressure Recorders at regulator stations described above for which PG&E has changed the technology, such that it cannot reasonably forecast 378 of those types of devices to be installed in 2014; therefore, PG&E cannot schedule the 2014 deployment of devices requiring SCADA in coordination with those other devices. Given the unfinished state of the technology, the tardiness of the schedule to date, and need to coordinate schedules with the Electronic Pressure Recorders at regulator stations, PG&E's forecast of 127 devices requiring SCADA technology is unreasonable.

PG&E additionally noted that in order to install its RTUs it usually needs to obtain several permits from town, city or county, and may need to: hold public hearings; deal with other jurisdictions such as public transit agencies, port authorities, state and national park services; revise permits due to changed schedules; receive environmental permits from agencies such as the Department of Fish and Wildlife or Air Quality Board; and, most importantly, gain customer

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[232] Ex. 99 (DRA-10-WP), pp. 152-154, PG&E Response to DRA-81, question 6; Tr. Vol 13, 1224:25-1225:8 (Christopher).

[233] Tr. Vol. 13, 1226:8-16 (Christopher).

[234] Tr. Vol. 13, 1226:17-28 (Christopher).

[235] Tr. Vol. 13, 1227:4-13 (Christopher); *see* Ex. 99 (DRA-10-WP), pp. 152-154, PG&E Response to DRA-81, question 6.

[236] Ex. 99 (DRA-10-WP), pp. 152-154, PG&E Response to DRA-81, question 6(h).

permission for some installations.[237] On cross-examination Mr. Christopher claimed that the customer permission issue has largely been overcome as PG&E is "essentially 95 percent successful when we go to a customer's home to get authorization to install an ERA device,"[238] although Mr. Christopher noted he did not know how many devices had been installed in 2013 and provided no hard data to support this assertion. Given the delays and technology changes noted above, the need to obtain so many permits as well as customer permission, and the clearly arbitrary time periods over which PG&E proposes to spread the work due to "resource constraints" that magically vanish when PG&E needs to accelerate a schedule to make up for delays, DRA reiterates its recommendation that the Commission adopt the 2013 estimated capital spending as the 2014 forecast.

3.3 Gas Distribution Mapping and Records

PG&E requests $16.2 million in expenses for work activities associated with the company's initiative to collect, transport, scan and archive over 15,000 linear feet of company-wide Gas Distribution as-builts into an enterprise records management system and for an increase in the number of mappers needed to maintain maps and records in 2014.[239] DRA recommends $3.6 million, an increase of $1.5 million or 70% over 2012 recorded costs of $2.1 million.[240] "As-Built records are records associated with a job installation or modification of an asset. And these are the red line drawings associated with what was actually installed in the field. It includes drawings, material specifications, permits, purchase orders, a lot of relevant information, pressure test information about the as installed condition and state of the asset."[241] PG&E estimated a total of 30,000 linear feet of records for Electric and Gas as-builts combined, based on what it claims are results of an in-house survey (originally claimed to be a third-party survey, and without the actual questions of the survey provided despite being requested[242]) that

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[237] Ex. 99 (DRA-10-WP), pp. 155-158, PG&E Response to DRA-81, question 8.

[238] Tr. Vol. 13, 1222:3-1223:4 (Christopher).

[239] Ex. 77 (DRA-9), p. 22, *citing* Ex. 15 (PG&E-3 WP 2-6), p. WP 3-5.

[240] Ex. 77 (DRA-9), p. 24.

[241] Tr. Vol. 14, 1261:26 -1262:7 (Singh). *See also* Ex. 54 (PG&E-18 Vol. 2) p. A-11 & Ex. 98 (DRA-9-WP), PG&E Response to DRA 39 Question 1.

[242] *See* Tr. Vol. 14, 1263:28-1264:19 (Singh). During cross-examination, PG&E witness Singh revealed

listed a total of 24,344 feet for 32 of 35 of PG&E's regional offices.[243] To estimate the remaining 5656 feet for the remaining three offices:

> First, is an assumption that was made about the linear footage of the records in the three offices, plus the additional records generated for gas and electric over the course of the last three years for each of the 35 offices.[244]

When asked where this information is provided, PG&E witness Singh stated:

> That information has not been provided in the response or the testimony, and that was based on subject matter expertise and assessments based on the number of jobs that have been completed and our experience with the recently completed MAOP validation effort, which was the gathering of the As-Built records, collection, scanning, indexing for our transmission pipeline system.[245]

PG&E then converted this estimate of 30,000 linear feet of records combined for electric and gas into an estimate of 15,000 linear feet for gas alone,[246] but when asked how PG&E determined this 50/50 split between electric and gas, PG&E conceded that "[t]here's no prescriptive information that's been provided in the testimony or the response."[247] As of the time of filing of their application, PG&E had no current count of gas distribution as-builts that had been mapped electronically.[248]

DRA's cost recommendations are based on 10,000 linear feet of records for gas, in the absence of convincing evidence that PG&E's estimate of 15,000 feet is reasonable. DRA also recommends a five-year period to complete this task, rather than the three-and-a-half year period requested by PG&E, because unlike transmission where the MAOP issues associated with San

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that the survey was dated July 2010. Tr. Vol. 14, 1266:3-4 (Singh).

[243] Ex. 54 (PG&E-18 Vol. 2) pp. A-11 to A-13 & Ex. 98 (DRA-9-WP), PG&E Response to DRA 39 Question 1; Tr. Vol. 14, 1263:5-27 & 1264:20 – 1265:19 (Singh).

[244] Tr. Vol. 14, 1226:9-20 (Singh).

[245] Tr. Vol. 14, 1226:21 – 1227:4 (Singh).

[246] Tr. Vol. 14, 1267:5-11 (Singh).

[247] Tr. Vol. 14, 1267:20-1268:8 (Singh).

[248] Ex. 77 (DRA-9), p. 28 & fn. 78, *citing* Ex. 98 (DRA-9-WP), PG&E response to DRA-39, question 6.

Bruno are paramount and as-built records validate transmission MAOP,[249] there is not such a compelling need to validate MAOP for the distribution system. DRA summarized its cost elements that comprise DRA's proposed $3.3 million in Table 9-10 for MWC GF[250] and PG&E's proposed $14 million in Table 9-9. The other main difference between DRA and PG&E's proposals in these tables are the amount of scanned images per as-built record. PG&E's assumptions are also only "based on a sampling"[251] of its records, the contents of which have not been provided elsewhere in testimony, and also a calculation of an average 2000 documents per linear foot "based on historical data"[252] that is also not provided. DRA rejects the request of $1.3 million of contingency expenses as unnecessary.[253]

DRA also recommends a $1.7 million reduction to PG&E's forecast of $2.1 million in headcount and associated expenses to perform gas distribution mapping base work and to eliminate a purported backlog.[254] The reduction is due to the use of an incorrect 2011 year base amount of $970,000, which PG&E claims to have corrected in an errata to its workpapers dated June 28, 2013.[255] PG&E's correction appears to be a shuffling of the 2011 recorded expenses for MWC GF from electric distribution to gas distribution without a reconciliation to the electric distribution expenses. In the original PG&E workpapers there are zero expenses for gas distribution recorded for 2011.[256] The $970,000 total expense recorded for MWC GF in 2011 was allocated to electric distribution. In the errata dated June 28, 2013, PG&E transferred the total expense to gas distribution.[257] PG&E's corrected allocation of the 2011 recorded mapping expense to gas distribution must be reconciled with a correction to the electric distribution

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[249] Tr. Vol. 14, 1271: 17-21 (Singh); Ex. 77 (DRA-9), p. 26.

[250] Ex. 77 (DRA-9) & Ex. 321 (DRA-9-E), Table 9-10, p. 30.

[251] Ex. 15 (PG&E-3 WP 02-06), p. WP 3-7, line 6. Without any details about the sampling, PG&E cannot confirm that 5% of documents are oversized, and 90% of the remaining 95% are double-sided.

[252] Ex. 15 (PG&E-3 WP 02-06), p. WP 3-7, line 5.

[253] Ex. 77 (DRA-9), p. 30.

[254] Ex. 77 (DRA-9), p. 31.

[255] Ex. 53 (PG&E-18), p. 3-9 and fns. 24-25, *citing* Ex. 15 (PG&E-3 WP 02-06), p. WP 3-4 and June 28, 2013 errata.

[256] Ex. 15 (PG&E-3 WP 02-06), p. WP 3-3.

[257] Ex. 50 (PG&E Errata), p. 15-40.

expense of the same amount. DRA checked PG&E's electric distribution expense testimony[258] and the subsequent two errata PG&E submitted on March 19, 2013,[259] and June 28, 2013, and found no changes to the 2011 recorded expense for electric distribution mapping to reflect the reconciliation of the $970,000. As such, the Commission should reject PG&E's claim that the 2011 expense was corrected. PG&E has not justified the inclusion of the 2011 expense in the 2014 forecast. DRA also rejects a 14.81% increase to the base level of costs, as the increased 26 mappers should be sufficient.[260]

3.4 Gas Distribution Integrity Management Program

PG&E forecasts $47.3 million in costs in 2014 for its Gas DIMP, a Federally mandated initiative.[261] DRA recommends $12.1 million,[262] based on PG&E's lack of support for many elements of its DIMP proposal, but proposes that the Commission adopt a two-way balancing account for DIMP costs capped at the average 2011-2012 spending level of $25.6 million in recognition of the importance of DIMP spending.[263]

DRA recommends that the Commission deny the entirety of PG&E's requested $2 million for Leak Survey Enhancement due to recovery in other accounts, and in rebuttal testimony PG&E conceded that there should be a reduction of $1.5 million to its forecast in MWC JS, with the remaining $0.5 million included as DIMP as program management costs.[264] DRA does not object to the inclusion of $0.5 million in DIMP.

PG&E forecasts $14.5 million in 2014 expenses associated with its project to prevent cross-bores in sewers, up from $2.3 million in 2011.[265] DRA forecasts $2.0 million. PG&E's forecast is based on an estimated scope of 500,000 services performed over a ten-year period,

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[258] Ex. 17 (PG&E-4).

[259] Ex. 49 (PG&E Errata).

[260] Ex. 77 (DRA-9), p. 33.

[261] Ex. 77 (DRA-9), p. 34, Table 9-12; Ex. 14 (PG&E-3), p. 4-37.

[262] Ex. 77 (DRA-9), p. 34, Table 9-12.

[263] Ex. 77 (DRA-9), p. 33. PG&E spent $24.7 million in 2011 and $26.6 million in 2012 on DIMP costs. *Id.*, p. 35, Table 9-13. PG&E estimated $30.3 million in 2012 DIMP spending. *Id.*, p. 34.

[264] Ex. 53 (PG&E-18), p. 4-8.

[265] Ex. 77 (DRA-9), p. 38 and fns. 114-115, *citing* Ex. 14 (PG&E-3), p. 4-19 & 4-18.

ramping up from 10,000 in 2012 to 25,000 in 2014 (down from the estimate in the application of 30,000).[266] The ten-year scope of the project is an estimate and still not final.[267] PG&E inspected 5284 laterals in 2011; 11,208 in 2012; and "nearly 5000" for slightly more than the first half of 2013.[268]

DRA further proposed that ratepayers not pay for inclusion of Gas Pipeline Replacement Program (GPRP) and Copper Service Replacement Program (CSRP) mains and services installed after 2007 because PG&E was aware of the problem of cross-bores then but did not perform video inspections for cross-bores during installation.[269] DRA recommends a much smaller scope to the cross-bore program based on DRA's exclusion of mains and services installed after 2007, and forecasts a four-year program of 6000 inspections in 2014.[270] Based on a $250 unit cost per inspection, and a repair rate of 1.6% at $5000 per repair, DRA recommends $2 million, comparable to PG&E's 2012 recorded expenses.[271]

In the category of Program Management, PG&E requests $13.6 million for 2014, including $4.4 million for DIMP management, $1.4 million for contractor support to develop its risk algorithm, and $7.3 million to implement a new Plastic Tee Cap program.[272] In 2011, PG&E spent $1.8 million on DIMP management and $0.6 million on contractor support.[273] DRA recommends a 2014 forecast of $2.3 million for DIMP management, the 2012 recorded cost level for this program, because most of the DIMP activities are already in place, there are fewer DIMP activities proposed for 2014 than for 2011 or 2012, and DRA recommends reductions to the cross-bore, emergent work, and tee cap programs and hence management costs should be lower than forecasted as well.[274] For contractor support, PG&E forecasts $1.4 million,

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[266] Ex. 77 (DRA-9), p. 42; Tr. Vol. 14, 1335:17- 1337:11 (Cowsert Chapman), *citing* Ex. 54 (PG&E-18 Vol. 2) pp. A-41 to A-43, PG&E response to DRA-49 question 5.

[267] Tr. Vol. 14, 1337:12-26 (Cowsert Chapman)

[268] Tr. Vol 14, 1338:27-1339:14 (Cowsert Chapman).

[269] Ex. 77 (DRA-9), pp. 44-45; Tr. Vol. 14, 1340:4 – 1341:8 (Cowsert Chapman).

[270] Ex. 77 (DRA-9), pp. 45-47.

[271] Ex. 77 (DRA-9), p. 49.

[272] Ex. 77 (DRA-9), p. 49.

[273] Ex. 77 (DRA-9), pp. 49, 50.

[274] Ex. 77 (DRA-9), p. 52 and fns. 162 & 163, *citing* Ex. 14 (PG&E-3), p. 4-14, Table 4-1.

although in 2012 it only spent $0.4 million out of a forecasted $3.4 million, and is using the same contractors in 2014 as it has before.[275] As for the new Tee Cap Repair/Replacement program for which PG&E forecasts $7.3 million, DRA recommends no funding, noting that PG&E was aware of tee cap issues well before the 2011 leak cluster analysis, has been repairing and tracking tee caps from 2007-12 in a different category, MWC FI, albeit without separating out specific expenses for tee caps.[276] PG&E has also not completed a pilot study of the issue. PG&E does not have a basis for specifically estimating 1000 tee caps to be repaired.[277] PG&E argues that tee caps are so dangerous that there is no time to wait for the pilot program,[278] but given that they have been repairing tee caps already and have no specific reason to all of a sudden include such costs in DIMP, the Commission should not adopt any DIMP costs now for tee cap repair.

DRA also recommends that the Commission deny PG&E funding for what it terms as Emergent Work of $10 million, more than 20% of its total request. PG&E concedes it has "not identified specific projects" for this work, but claims this request is reasonable because the purpose of DIMP is to identify new threats and new mitigation measures for new and old threats.[279] Given PG&E's large requested increase in DIMP funds, from $26.6 million in actual costs in 2012 to $47.3 million in 2014, for which its support has been skimpy, the Commission must deny a request for $10 million not intended for any specific projects. As PG&E's proposed ratemaking treatment for DIMP would not require PG&E to spend DIMP money as allocated in a Commission decision, to grant money for unspecified programs is an invitation for reallocation to other purposes. Indeed, this proposal underscores the need for a two-way balancing account for DIMP costs, as PG&E concedes it cannot specify in advance what costs are necessary to fulfill its DIMP functions.

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[275] Ex. 77 (DRA-9), p. 51.

[276] Ex. 77 (DRA-9), p. 53.

[277] *Id.*

[278] Ex. 53 (PG&E-18), p. 4-26.

[279] Ex. 53 (PG&E-18), p. 4-26.

3.4.1.1 Two-Way Balancing Account[280]

DRA proposes that a two-way balancing account with a cap at PG&E's average spending for its two years of 2011-2012 average DIMP spending of $25.6 million. As DRA witness Phan testified, the two-way balancing account:

> recognizes that DIMP is an important part of PG&E's effort to ensure system safety and reliability and provides funding for additional work above the recommended level. The cap encourages PG&E to be efficient in its spending and protects ratepayers from excessive rates. This will also address the fact that PG&E's risk algorithm is still in development. PG&E did not rely on any risk analysis or ranking using DIMP protocol/risk algorithm to develop its 2014 DIMP forecast. Instead, PG&E uses the company's leak history to plan projects for 2014 because the risk algorithm cannot be used at this time. Once PG&E uses the risk algorithm to identify DIMP projects, new projects could be identified and the ones identified for the 2014 GRC could be abandoned.[281]

Currently, PG&E has a one-way balancing account for DIMP costs, adopted as part of a settlement of the prior GRC. A capped, two-way balancing account does have some similarities to a one-way balancing account in that costs above the cap in a two-way account or the adopted amount in a one-way account limit recovery of utility costs, and costs above that cap are not directly recoverable, but must be funded through other means.

The Independent Review Panel (IRP) argued that "[o]ne-way balancing accounts create a perverse incentive for the utility to spend exactly as the stakeholders have negotiated – spending no less or no more than is authorized for a given activity."[282] The IRP report reflects little understanding of the purpose and objective for a one-way balancing account relative to the GRC process and structure. DRA denies that for DIMP costs, this is a "perverse" incentive. Costs allocated to meet this important, Federally-mandated program should not be allocated for other purposes at PG&E's discretion. DRA's review noted the insufficiency of PG&E's support for its requested costs for specific items, particularly for Emergent Work, but PG&E should be given the opportunity to recover a reasonable level of costs for actual DIMP work once it determines

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[280] In the draft outline, PG&E titled this section "One-Way Balancing Account," which is incorrect. DRA failed to catch this and renames it to correctly reflect DRA's proposal. *See* Ex. 77 (DRA-9), p. 59.

[281] Ex. 77 (DRA-9), p. 59.

[282] Independent Panel Review, p. 107, found at Ex. 53 (PG&E-18), p. 11B-115.

what to do. DRA would oppose an uncapped, two-way balancing account because it would not provide PG&E an incentive to reduce its costs. Even if PG&E spends more than the cap, it has the opportunity to reallocate resources from its other activities to cover such costs, and will have the opportunity in the next rate case to file for a higher level of costs.[283]

3.5 Pipe, Meter and Other Preventative Maintenance

3.5.1 Expense

PG&E requests $84.4 million in expenses for preventative maintenance in 2014, a $24.5 million increase over 2011 actual spending of $59.9 million.[284] DRA recommends $69.4 million, based on a lower forecast for Locate and Mark activities associated with Underground Service Alert (USA) tags and adjustments to PG&E's proposals for activities in MWC FH.

DRA recommends adjustments for three aspects of PG&E's Locate and Mark activities. For the MAT_NA sub-category covering USA membership and associated support costs, PG&E estimated $1.1 million without any discussion in opening testimony other than a reference to one line in a table,[285] and bare mention in the workpapers. PG&E only spent $0.3 million in 2011.[286] On rebuttal, PG&E referenced three lines in its workpaper that they claim justify the increase of $0.8 million,[287] but the "detailed description/assumptions" in these lines don't discuss how or why USA North and South membership costs change over time so dramatically, nor the background for "miscellaneous DF expenses." PG&E also claims that they spent $2.4 million in 2012 on these activities, but provides no breakdown of such spending nor how such costs continue into 2014.[288] The Commission should adopt DRA's proposal of $0.8 million, which is the 2009-2011 three-year average of spending and $0.5 million above 2011 spending.[289]

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[283] *See* Independent Panel Review, p. 105, found at Ex. 53 (PG&E-18), p. 11B-113.

[284] Ex. 77 (DRA-9), p. 60.

[285] Ex. 14 (PG&E-3), p. 5-12, Table 5-3 line 1.

[286] *Id.*

[287] Ex. 53 (PG&E-18), p. 5-5, *citing* Ex. 15 (PG&E-3 WP 02-06), p. WP 5-26, lines 4, 9, and 14.

[288] Ex. 53 (PG&E-18), p. 5-5.

[289] Ex. 321 (DRA-9-E), p. 63.

For Locate and Mark-DFA activities, DRA recommends $32.6 million rather than PG&E's proposal of $36.8 million.[290] PG&E estimated 12% growth in USA tickets from 2012 to 2013 and 2013 to 2014 based on the judgment of its expert without any further calculations.[291] On rebuttal, PG&E claimed that these figures were derived from Moody's forecasts of residential and non-residential growth rates for 2012 – 2014, to which "PG&E applied judgment" to come up with its year-to-year growth rates, although PG&E does not explain how, for example, the different rates in Moody's forecast for 2013 and 2014 both yield 12% growth rates in tickets.[292] PG&E's unstated methodology is not reasonable. DRA recommends use of the 6% actual growth rate for 2012 to forecast increases in 2013 and 2014. DRA also recommends the continuation of use of a 60% work rate from 2010, as PG&E's claim of a higher growth rate for 2012 in rebuttal testimony is based on year-end 2012 numbers which they did not provide on discovery and for which they have no referenced support.[293]

DRA also recommends that PG&E's estimate of $1.1 million for standby and spot check work associated with Mark and Locate activities be reduced to $0.5 million, because PG&E's application contained no supporting analysis or documentation for the proposed new spot checks that are essentially similar to standby work.[294] On rebuttal, PG&E claims it did provide documentation in its response to DRA-69 question 15 discussing additional spot checks in its new "repeat offender" program, but that data response admitted that "PG&E applied professional judgment" to estimate elements comprising the costs of this new program.[295]

For preventative maintenance activities under MWC FH, PG&E forecasts $22.6 million and DRA recommends $19.2 million.[296] The differences regard PG&E's request for a new dedicated painting crew, Atmospheric Corrosion Monitor and Correction, and Special

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[290] Ex. 77 (DRA-9), p. 62.

[291] Ex. 77 (DRA-9), pp. 63-64 and fns. 203 & 204 *citing* Ex. 98 (DRA-9-WP), PG&E Data Responses to DRA-69 questions 14 & 11.

[292] Ex. 53 (PG&E-18), p. 5-7.

[293] Ex. 53 (PG&E-18), p. 5-8 and fn. 20. PG&E has provided no support for its 607,133 number of total tickets for 2012 and that it worked 395,805 of these tickets.

[294] Ex. 77 (DRA-9), p. 66 and fns. 209 & 211, *citing* Ex. 98 (DRA-9-WP), PG&E Data Responses to DRA-69 questions 20 & 15.

[295] Ex. 53 (PG&E-18), p. 5-9, *citing* Ex. 98 (DRA-9-WP), PG&E Data Responses to DRA-69 question 15.

[296] Ex. 77 (DRA-9) & Ex. 321 (DRA-9-E), p. 68 and Table 9-23.

Projects.[297] PG&E recommends $4.7 million for MAT_NA, the category that includes painting costs, a $3.5 million increase over 2011 costs,[298] of which $3.1 million is for the new, dedicated painting crew.[299] In 2011, PG&E only spent $0.1 million on painting, and 743 total labor hours, yet estimates $3.1 million of spending in 2014 for based only on its claim that it needs "5 crews x 3 men per crew x 40 working weeks per year x 40 hours per week x 130 per hour."[300] In 2012, PG&E spent less than $0.2 million.[301] On rebuttal, PG&E concedes that "painting of above-ground gas distribution assets is, for the most part, currently combined with other preventative maintenance activities,"[302] and reiterates claims that it needs dedicated resources because historically "painting has received insufficient emphasis,"[303] without explaining why this has been the case or how past funding was not reasonable. Even Cycla notes it could be more cost-effective not to have dedicated paint crews.[304] PG&E also did not provide any further support for the $3.1 million. DRA recommends adoption of $1.3 million, PG&E's proposed amount with escalation excluding the dedicated paint crew.[305]

DRA recommends $1.5 million for Atmospheric Corrosion, compared with PG&E's forecast of $4.7 million. PG&E's stated reason of meeting a three-year frequency is insufficient because this requirement has been in place since 2003 and PG&E has not previously needed additional resources beyond the $1.5 million it spent in 2011 for this account.[306] PG&E also claims it may need additional inspectors for corrosion inspections due to the installation of Smart Meters, as such inspections were performed by meter readers or leak surveyors at minimal

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[297] Ex. 77 (DRA-9), p. 68.

[298] Ex. 77 (DRA-9), p. 69.

[299] Ex. 53 (PG&E-18), p. 5-11.

[300] Ex. 77 (DRA-9), p. 70 and fns. 222 & 224, *citing* Ex. 98 (DRA-9-WP), PG&E Data Responses to DRA-77 question 7.

[301] Ex. 77 (DRA-9), p. 71.

[302] Ex. 53 (PG&E-18), p. 5-11.

[303] Ex. 53 (PG&E-18), p. 5-10.

[304] Ex. 167 (Cycla), Attachment 6, pp. 17-18; Ex. 53 (PG&E-18), p. 5-12 and fn. 28.

[305] Ex. 77 (DRA-9), p. 71.

[306] *See* Ex. 77 (DRA-9), p. 73.

incremental cost.[307] On rebuttal, PG&E newly claimed that PG&E had actually performed work in other accounts so that the $1.5 million figure it provided was not accurate and an understatement, because AC inspections transitioned away from meter readers.[308] To the extent there are purported additional costs caused by the installation of Smart Meters, the savings associated with the installation of Smart Meters, which PG&E claimed supported such installation, should cover such costs. Ratepayers should not have to pay such post-hoc increased costs that were not previously disclosed when Smart Meters were proposed. The Commission should disregard PG&E's comment on rebuttal that the $1.5 million in actual 2011 costs in this account did not count costs associated with the move away from meter reading. The incremental costs associated with Picarro are also unsupported, because if Picarro is utilized in addition to foot surveyors rather than as a substitute, PG&E will not have to perform the work separately.[309]

With respect to Special Operations costs associated with raising the height of low elevation vents, DRA proposes a five-year schedule rather than the three-year schedule set forth by PG&E.[310] DRA noted that PG&E's Gas Engineering and Operations team proposed a five-year program.[311] PG&E has not explained why this new program is so important that it must be performed in three rather than five years, especially when its own Gas Engineering and Operations team proposed as a corrective action to "[d]evelop a 5 year program."[312] The Commission should adopt DRA's recommendation of $1.7 million.

3.5.2 Capital Expenditures

DRA forecasts a capital expenditure of $5,000, the actual spending from 2012, rather than PG&E's forecast of $246,000, based on declining actual spending from 2011 – 2012.[313]

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[307] Ex. 77 (DRA-9), p. 75.

[308] Ex. 53 (PG&E-18), p. 5-17.

[309] *See* Ex. 53 (PG&E-18), p. 5-19.

[310] Ex. 77 (DRA-9), p. 78: Ex. 53 (PG&E-18), p. 5-13.

[311] Ex. 77 (DRA-9), p. 78 fn. 253, *citing* Ex. 98 (DRA-9-WP), PG&E Data Responses to DRA-77 question 6(a) attachment 2.

[312] PG&E Data Responses to DRA-77 question 6(a) attachment 2.

[313] Ex. 78 (DRA-10), pp. 16-18.

3.6 Leak Survey and Repair

PG&E has focused a lot of attention on improving its leak survey and repair program, and the use of new equipment will significantly increase the amount of leaks it finds on its system. However, PG&E has not yet completed a risk assessment for leaks,[314] and acknowledges the conclusion of Cycla that "excavation damage … is the largest contribution to PG&E distribution risk,"[315] despite the overarching emphasis on capital spending on pipe replacement and expenses for leak survey. While in the wake of San Bruno an increased emphasis on finding leaks is certainly recommended even for the distribution system, the lack of a risk assessment combined with PG&E's much larger attention towards leaks than preventing dig-ins has led to extraordinarily large recommended increases. Moreover, as increasingly sensitive equipment detects more and more "non-hazardous" Grade 3 leaks, which need to be periodically rechecked again under regulations and which PG&E proposes to fix rather than recheck for cost savings, a large amount of costs will be dedicated to finding and repairing leaks that are currently non-hazardous, an unreasonable use of resources. PG&E does not have a current problem of Grade 3 leaks becoming hazardous.[316]

3.6.1 Expense

PG&E forecasts $33.8 million for leak surveys in MWC DE in 2014, a 71% increase, and $102 million for leak repairs in MWC FI, a 174% increase.[317] The cost increase for leak survey is due to the proposed switch from a five-year to three-year cycle of inspection.[318] The cost increase for the leak repair and corrective maintenance is due to utilizing new leak detection technology and the increased sensitivity of such technology, changing from a five-year to three-year cycle, and repairing above-ground Grade 3 leaks within 15 months.[319] DRA recommends

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[314] Ex. 167 (Cycla), p. 48. ("While PG&E has yet to develop a quantitative risk assessment tool, it would seem that this evaluation could be done, using leaks identified and repaired as a proxy for risk, with available tools PG&E has developed to estimate changes in the number of leaks requiring repair.")

[315] Ex. 53 (PG&E-18), p. 5-8, *citing* Ex. 167 (Cycla), Attachment 6, p. 14.

[316] *See* Tr. Vol. 14, 1417:13-17 (Redding).

[317] Ex. 77 (DRA-9), pp. 80, 81.

[318] Ex. 77 (DRA-9), p. 81.

[319] *Id.*

$17.5 million for MWC DE, and $35.6 million for MWC FI.[320] PG&E has also recommended an uncapped, two-way balancing account for the costs of these two MWCs as well as the costs for meter set leak repair costs (MWC HY) and the cost of atmospheric corrosion (MWC FH).[321] DRA opposes an uncapped, two-way balancing account as discussed below in Section 3.6.2.

PG&E currently inspects 94% of its system on a five-year rather than a three-year cycle.[322] Moreover, despite maintaining that over half of respondent utilities to a questionnaire reported leak surveying their entire system on a three-year basis comprising industry "best practices," the support for this statement is an industry group letter to PG&E that said that "over 50% responded that the leak survey their entire natural gas system" for "[u]nprotected pipe at least once every three years" and for "[p]lastic and protected pipe at least **once every five years**."[323] PG&E has reported no "unprotected" pipe.[324] PG&E inspects copper services, cast iron mains, and unprotected steel mains on a three-year cycle already.[325] PG&E's current five-year leak cycle for protected pipe is in line with industry best practices.[326] Just because moving to a shorter leak cycle could find more leaks is no justification for a three-year cycle, and while PG&E failed to perform a risk assessment regarding leaks, it did provide a cost-benefit analysis that showed no cost savings associated with moving from a five-year to three-year leak cycle.[327] Moreover, despite implying otherwise, PG&E's system has seemingly been safer in recent years, as the system average leak rate per mile decreased from 0.29 in 2009 to 0.16 in 2011.[328] The leak rate for services has also declined from 4.71% in 2009 to 2.85% in 2012.[329]

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[320] Ex. 321 (DRA-9-E), p. 81, Table 9-27.

[321] Ex. 77 (DRA-9), p. 80.

[322] Ex. 77 (DRA-9), p. 84 and fn. 270, *citing* Ex. 14 (PG&E-3), p. 6-9.

[323] Ex. 77 (DRA-9), pp. 85-86 and fns. 272-274, *citing* Ex. 15 (PG&E-3 WP02-06), p. WP 6-29; Ex. 14 (PG&E-3), p. 6-15; Ex. 98 (DRA-9-WP), PG&E data response to DRA-DEF 10(c) question 1, Attachment 1.

[324] Ex. 77 (DRA-9), p. 86 and fn. 275, *citing* Ex. 15 (PG&E-3 WP02-06), p. WP 5-72.

[325] Ex. 77 (DRA-9), p. 84.

[326] *See* Ex. 77 (DRA-9), p. 86.

[327] Ex. 77 (DRA-9), p. 85. Ex. 15 (PG&E-3 WP02-06), pp. WP 6-25 to 6-29 (no cost savings p. WP 6-28).

[328] Ex. 77 (DRA-9), p. 105, *citing* Ex. 98, PG&E Response to DRA-31, question 10.

[329] Ex. 77 (DRA-9), p. 105, *citing* Ex. 15 (PG&E-3 WP 02-06), p. WP 6-94; Tr. Vol. 26, 3818:18-3821:17

DRA recommends "PG&E retain the current 5-year leak survey cycle and perform a total of 841,012 surveys at PG&E's proposed unit cost of $15.25 per survey for 2014. The number of survey units is the average of the number of actual surveys performed in 2011, and the planned surveys for 2012 and 2013."[330] PG&E should perform half the survey using traditional foot surveys, and half with the new Picarro surveyor, as PG&E indicated in discussions with DRA that PG&E might have issues ramping up so quickly to process the increased leaks Picarro is expected to find.[331] DRA forecasts the leak survey cost of $7.6 million for 2014, based on PG&E surveying 420,506 services at the PG&E proposed unit cost of $15.25 per survey using the traditional methods, and 420,506 services at the PG&E proposed unit cost of $2.67 per survey using the Picarro Surveyor.[332] With respect to leak clusters, DRA recommends using the same survey rate that PG&E utilized in 2012 and 2013 for 2014, as PG&E has offered no risk assessment justifying an increased rate.[333] With respect to the Picarro leak rate, DRA does concede that its proposed 3.25% rate is only an estimate and not reflective of the rates submitted in Picarro's rebuttal testimony, and reserves the right to review the proposals of other parties in Opening Brief and respond if appropriate. There are issues with extrapolating leak rate data from the Sacramento and Diablo divisions, the first and fifth worst divisions in PG&E's service territory, to the entire system.[334]

With respect to re-checks of non-hazardous leaks, DRA opposes PG&E's proposal of rechecking such leaks once a year, rather than every fifteen months as consistent with ANSI guidelines.[335] PG&E claims it has to recheck every twelve months "to give a 3 month cushion"[336] but does not include such a cushion in its other leak cycles, let alone a cushion that amounts to a 20% reduction. PG&E does not, for example, suggest that it survey its gas system

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(correcting 1.5% leak rate figure shown in Ex. 77, p. 105 to 2.85%).

[330] Ex. 77 (DRA-9), p. 91.

[331] Ex. 77 (DRA-9), p. 92; *see* Tr. Vol. 26, 3861:20-3862:5 (Phan).

[332] Ex. 77 (DRA-9), p. 93.

[333] *See* Ex. 77 (DRA-9), pp. 97, 99.

[334] *See* Ex. 77 (DRA-9), pp. 103-104.

[335] Ex. 77 (DRA-9), p. 109.

[336] Ex. 53 (PG&E-18), p. 6-38.

every 48 months rather than every 60 months in a five-year cycle. Moreover, these are Grade 3 leaks and do not require such an aggressive approach. PG&E has offered no risk assessment comparing a 12-month to a 15-month cycle. PG&E's request to re-check such leaks even faster than the ANSI guidelines must be rejected, and DRA's $1.3 million reduction reasonably allows PG&E to meet the guidelines. DRA's estimate of $5.1 million is an increase over the 2011 recorded amount of $4.7 million.[337]

PG&E requests $2.6 million in expense for "Other work activities," which are the incremental costs of using Picarro.[338] PG&E did not adequately quantify how it calculated 8.5 FTEs for its operations,[339] and its rebuttal testimony merely describes the tasks of these employees without sufficiently detailing why the numbers are reasonable.[340]

For leak repair expense, MWC FI, PG&E requests $102.1 million in 2014, $64.8 million higher than the 2011 recorded expense amount of $37.3 million, a whopping 174% increase.[341] DRA recommends $35.6 million for 2014, based on DRA's recommendations that PG&E remain on the current five-year leak survey cycle and utilize lower leak rates.[342] PG&E proposes to increase spending for below-ground Service Leak Repairs from $0.1 million to $40.7 million, and for main leak repairs from $11.7 million to $38.7 million.[343] DRA recommends $12.0 million and $11.3 million respectively for these two categories, and $3.5 million for above-ground Service Leak Repairs as opposed to PG&E's forecast of $14.0 million.[344] PG&E forecasts performing more than 43,827 leak repairs in these categories in 2014, after only performing 13,481 repairs in these categories in 2011, and in much different proportions.[345] After only recording 26 repairs of service leak below ground in 2011, PG&E forecasts 13,496 such repairs in 2014. PG&E's assumption that they will both find so many more leaks and

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[337] Ex. 77 (DRA-9), pp. 108, 109.

[338] Ex. 53 (PG&E-18), p. 6-38.

[339] Ex. 77 (DRA-9), p. 112.

[340] *See* Ex. 53 (PG&E-18), pp. 6-39 to 6-40.

[341] Ex. 77 (DRA-9), p. 112.

[342] Ex. 77 (DRA-9), p. 114.

[343] Ex. 77 (DRA-9), pp. 112-113.

[344] Ex. 77 (DRA-9), p. 114, Table 9-35.

[345] Ex. 77 (DRA-9), p. 116-117 and Table 9-36.

schedule so many more repairs than they have in recent years is simply not reasonable. The amount of repairs PG&E reported to PHMSA in recent years shows a declining, rather than increasing, trend.[346] PG&E's rebuttal mechanically adjusts DRA's recommendations to increase leak rates,[347] but never addresses DRA's point that PG&E will not in fact be able to repair all the high level of increased leaks it asserts it will find. DRA reiterates that use of a five-year cycle rather than a three-year cycle for PG&E's system, a 15-month rather than 12-month cycle for rechecks, and lower leak rates than suggested by PG&E and Picarro, results in a much more achievable and reasonable level of work for PG&E than PG&E's excessively aggressive forecasts. DRA's proposed 2014 leak repair by type and cost as detailed in Table 9-40 should be adopted.[348]

For Gas overbuilds, PG&E requests $2.2 million in 2014 to relocate an unspecified number of units, up from $1.3 million in 2011 to relocate 107 units.[349] DRA recommends adoption of $1.3 million. After DRA noted that PG&E's only support for an increase was its statement of its increased focus on the issue and expectation of an increase,[350] PG&E on rebuttal cited its initial testimony regarding new attention to mobile home parks.[351] However, the workpapers referenced in the initial testimony specifically noted that in 2014 there is "no mobile home build repair" and costs are only based on standard escalation,[352] contradicting the claim that mobile home parks contribute to the 2014 forecast. DRA also noted that overbuilds has previously been recorded with other costs, [353] and although on rebuttal PG&E claimed that its

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[346] Ex. 77 (DRA-9), pp. 117-118 & Table 9-37.

[347] Ex. 53 (PG&E-18), p. 6-41.

[348] Ex. 77 (DRA-9), p. 121, Table 9-40. *See generally* Ex. 77 (DRA-9) & Ex. 93C (DRA-9-Confidential), pp. 118-126.

[349] Ex. 77 (DRA-9), p. 128; Ex. 14 (PG&E-3), p. 6-37, Table 6-2, line 9; Tr. Vol. 14, 1422:14-24 (Redding).

[350] Ex. 77 (DRA-9), p. 128.

[351] Ex. 53 (PG&E-18), *citing* Ex. 14 (PG&E-3), p. 6-36.

[352] Ex. 14 (PG&E-3), p. 6-36, *citing* Ex. 15 (PG&E-3 WP 02-06) pp. WP6-20 to WP 6-24; *Cf.* WP 6-22 line 21, WP 6-24 line 33; Tr. Vol. 14, 1422:27 – 1425:2 (Redding).

[353] Ex. 77 (DRA-9), p. 129 & fn. 389, *citing* Ex. 14 (PG&E-3), p. 6-36 ("this work [gas overbuild expense] was formerly forecast under MWC EWM and now resides with gas expense.") *See* Tr. Vol. 14, 1425:8 – 27 (Bromson).

"testimony did not say this,"[354] on cross-examination PG&E witness Redding confirmed that "it [overbuilds] was under a different Major Work Category."[355] PG&E testimony indeed said that "costs associated with overbuilds … had previously been recorded with other costs."[356] DRA reiterates that the presence of such embedded costs renders PG&E's requested increase unreasonable.

3.6.2 Two-way Balancing Account

PG&E has recommended an uncapped, two-way balancing account for the costs of leak survey (MWC DE) and repair (MWC FI), meter set leak repair costs (MWC HY) and the cost of atmospheric corrosion (MWC FH).[357] Given the tremendously large requested increases in leak survey and repair in this proceeding, PG&E's argument that it needs an uncapped, two-way balancing account in case Picarro finds even more leaks than PG&E forecasts should be rejected. An uncapped, two-way balancing account provides no incentive for PG&E to control its costs, and provides incentives to find and repair even non-hazardous leaks. Because leak surveys and repairs are not new despite the adoption of some new technology, and because DRA's estimates of costs are more in line with actual recent costs, the Commission should adopt a reasonable estimate of costs for this account under traditional ratemaking principles.

DRA does appreciate, however, that PG&E argues that "it does not want customers to pay for the cost of repairing leaks that it does not actually find."[358] If the Commission believes a balancing account is necessary for gas leak and repair costs it must either establish a one-way balancing account, or a two-way balancing account with a cap. In either circumstance, PG&E would receive compensation of actual gas leak costs up to a limit, so that PG&E would not have the incentive to run up costs in this category.

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[354] Ex. 53 (PG&E-18), p. 6-47.

[355] Tr. Vol. 14, 1425:28 – 1426:15.

[356] Ex. 14 (PG&E-3), p. 6-36.

[357] Ex. 77 (DRA-9), p. 80.

[358] Ex. 14 (PG&E-3), p. 6-38.

3.7 Gas Field Services and Response

3.7.1 Expense

PG&E recommends $113.7 million in expenses in this category, a 48% increase over recorded 2011 expenses of $76.9 million.[359] DRA forecasts $102.1 million.[360] For MWC DD, covering field workers responding to gas odor calls, appliance pilot relights and safety checks, and similar work, PG&E recommends $106 million, and DRA recommends the 2012 recorded expense of $96.4 million.[361] The primary reason for the increase is PG&E's forecast of 80 additional Gas Service Representatives (GSRs) to meet a January 1, 2015 goal to respond to all gas odor calls within 30 minutes 75% of the time, and within 60 minutes 99% of the time.[362] This goal is similar to what PG&E proposed in the 2011 GRC.[363] The goal for Test Year 2014, however, is the same as it has been since 2012, a year in which PG&E met or exceeded the goals it will have in 2014.[364] The number of jobs PG&E has completed has fluctuated between 180,000 and 200,000 for the past few years,[365] and the estimate for 2014 of 197,259 jobs is within this range.[366] When asked why January 1, 2015 was chosen as the date to increase the standards – and require increased staffing levels in the Test Year 2014 to meet those goals – PG&E witness Yamaguchi only mentioned the need to make sure they had sufficient time for training to ramp up, but not specifically why that date rather than another one was chosen.[367] PG&E admits there is no external requirement driving the choice of January 1, 2015.[368] The reason PG&E requests 80 additional GSRs in 2014 is not to meet the goals in 2014, which are

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[359] Ex. 77 (DRA-9), p. 129.

[360] Ex. 77 (DRA-9), p. 130, Table 9-41.

[361] Ex. 77 (DRA-9), pp. 130, 131.

[362] Ex. 77 (DRA-9), pp. 130-131; Ex. 14 (PG&E-3), p. 7-19, Table 7-7; Tr. Vol. 15, 1474:10-26 (Yamaguchi)

[363] Tr. Vol. 15, 1474:27-1475:24 (Yamaguchi).

[364] *See* Ex. 14 (PG&E-3), p. 7-19, Table 7-7; Ex. 77 (DRA-9), p. 132; Ex. 53 (PG&E-18), p. 7-7; Tr. Vol. 15 1478:8-27, 1479:12-1480:2 (Yamaguchi).

[365] Tr. Vol. 15, 1476:24 – 1478:5 (Yamaguchi); Ex. 98 (DRA-9-WP), PG&E response to DRA-79, question 1.

[366] Tr. Vol. 15, 1476:12-23 (Yamaguchi).

[367] Tr. Vol. 15, 1480:27-1481:10 (Yamaguchi).

[368] Tr. Vol. 15, 1486:1-6 (Yamaguchi).

identical to those now which they are already meeting, but to prepare for January 1, 2015.[369] PG&E is not proposing to hire any GSRs in 2013[370] to meet this goal despite the need for training, nor any hires in 2015 to meet the goal later in 2015, but all 80 GSRs in the Test Year. PG&E's proposed increase is not necessary for 2014 and is not reasonable.

For expenses associated with atmospheric corrosion remediation in MWC HY, PG&E requests $7.8 million for 2014. In 2012, PG&E forecasted $12 million, and only spent $9.4 million. PG&E forecasted a 40% decrease in the level from 2012 to 2014, as 2012 levels were inflated to due to backlogs, and DRA recommends this decrease be applied to the actual spending of 2012 to determine a 2014 estimate of $5.4 million.[371] On rebuttal, PG&E noted that its estimate for 2014 of new leaks is adjusted for a three-year leak survey cycle,[372] so DRA's reduction is similar to the impact of keeping the current five-year leak survey cycle as DRA as recommended.

3.7.2 Capital Expenditures

PG&E is forecasting $14.9 million in capital expenditures to capture the labor costs to replace regulators that are capitalized in plant in service in MWC 74.[373] DRA recommends $3.5 million, based on the use of lower unit costs. DRA bases its residential unit cost estimate on the 2012 recorded unit cost, and commercial unit cost estimate as twice the cost of residential.[374] PG&E's own proposals are based on blended 2011 unit costs between commercial and residential, and PG&E failed to replace any of the 2924 commercial regulators it forecasted in 2012.[375]

3.8 Gas Distribution Capital and Investment Planning

For Gas Distribution Capital and Investment Planning capital expenditure forecasts covering MWCs 05, 14, 31, 47, 50, 52 and 2K, PG&E forecasts $299.2 million for 2012,

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[369] Tr. Vol. 15, 1483:24-1485:6 (Yamaguchi).

[370] Ex. 14 (PG&E-3), p. 7-19, Table 7-7.

[371] Ex. 77 (DRA-9), pp. 134-136.

[372] Ex. 53 (PG&E-18), p. 7-10.

[373] Ex. 78 (DRA-10), p. 19.

[374] *Id.*, pp. 23, 24.

[375] *Id.*, p. 22.

$360.3 million for 2013, and $531.6 million for 2014. DRA forecasts $256.4 million for 2012, $289.8 million for 2013, and $307.8 million for 2014. [376]

3.8.1 MWC 05

For Tools and Equipment, DRA recommends use of the five-year, 2007-2011 spending average of $1.4 million, as opposed to PG&E's forecast of $2.6 million.[377] PG&E's forecast is based partially on historical spending.[378] DRA reviews Fleet spending in Shared Services and Information Technology Costs below, Section 7.

3.8.2 MWC 14 -- Gas Distribution Pipeline Replacement Program

PG&E's Gas Distribution Pipeline Replacement Program (GPRP) replaces aging gas distribution pipe throughout its system, with a focus on cast iron, pre-1940 steel, copper, and plastic Aldyl-A pipe. PG&E proposes, starting in 2014, to replace 180 miles of distribution main per year,[379] up from its historical rate of 27 miles.[380] Of these miles, 20 miles are for post-1940 steel and recorded in MWC 50, and the remaining 160 miles are comprised of 100 miles of plastic pipes and 60 miles of cast iron and pre-1940 steel pipe.[381] PG&E forecasts capital costs of $172.2 million in 2012, $203.9 million in 2013, and $331.2 million in 2014. DRA forecasts capital costs of $167.9 million in 2012 (the actual level of 2012 costs), $198.3 million in 2013, and $215.7 million in 2014.[382] Recorded costs in MWC 14 from 2007-2012 ranged from $77 million in 2007, around $100 million in 2008-2010, $127 million in 2011, and $167.9 million in 2012.[383]

DRA's forecast for 2014 includes a forecast of 50 miles of pre-1940 steel and cast iron pipes rather than 60 miles. PG&E replaced 12 miles of such pipes in 2012 and forecasts 15 miles

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[376] *Id.*, p. 26, Table 10-16.

[377] *Id.*, p. 27.

[378] *Id.*

[379] *Id.*, p. 31.

[380] *Id.*, p. 33 and fn. 97, *citing* Ex. 16 (PG&E-3 WP 07-12), p. WP 8-5; Ex. 99 (DRA-10-WP), pp. 211-212, PG&E Response to DRA-173, question 4.

[381] Ex. 78 (DRA-10), p. 32 and fn. 87, *citing* Ex. 14 (PG&E-3), pp. 8-8 to 8-9.

[382] Ex. 78 (DRA-10), p. 39, Table 10-23 & fn. 106, *citing* Ex. 14 (PG&E-3), p. 8-26.

[383] Ex. 78 (DRA-10), p. 29, Table 10-19, *citing* Ex. 16 (PG&E-3 WP 07-12), p. WP 8-1.

in 2013.[384] PG&E still does not know what particular pipes it will replace, and only has a preliminary list of pipes by location, type of material, vintage, length of pipe, and reason for replacement.[385] On rebuttal, PG&E claims that it is "contrary to the concept of forecast ratemaking" for PG&E to "identify all capital projects with specificity."[386] PG&E claims it forecast a reasonable and prudent amount of pipe to replace and has a methodology to identify specific segments,[387] but PG&E's responses belies its claim it has any such methodology. For Aldyl-A plastic pipes, PG&E forecasts 100 miles of replacement although it only replaced 24 miles in 2012.[388] PG&E criticizes DRA's choice of 50 miles, but does not itself explain how it determined that 100 miles was appropriate, or that a fourfold increase in two years was achievable.[389] PG&E criticizes DRA's use of an escalated Aldyl-A unit cost for 2012, because the recorded units include the entire units of a project that become operational in a year, more than the actual units recorded during the year,[390] which itself suggests that PG&E's estimates of Aldyl-A units are inflated. Given the difficulties associated with PG&E's forecasts, the rapid and large increase in proposed miles to be replaced, and the lack of planning to date, DRA has proposed an alternate ratemaking methodology to traditional forecast ratemaking so that PG&E's actual spending up to its large requested increase are potentially recoverable, but DRA's recommended forecast should be adopted as a reasonable base level of expenses.[391]

3.8.3 MWC 31

For natural gas vehicles, PG&E forecasts $2.9 million of capital costs for 2014, and DRA recommends $1.4 million, equal to the recorded capital expenditures in 2012.[392] PG&E forecasted $2.8 million in 2012, although actual spending has declined each year from 2008 to

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[384] Ex 78 (DRA-10), pp. 35-36, *citing* Ex. 99 (DRA-10-WP), pp. 205-210, PG&E response to DRA-173 question 2.

[385] Ex. 78 (DRA-10), p. 36 and fn. 100, *citing* PG&E response to DRA-173 question 5.

[386] Ex. 53 (PG&E-18), p. 8-9.

[387] *Id.*

[388] Ex. 78 (DRA-10), p. 37.

[389] Ex. 53 (PG&E-18), p. 8-11.

[390] Ex. 53 (PG&E-18), p. 8-7.

[391] *See infra* Section 3.8.8.

[392] Ex. 78 (DRA-10), p. 40, 41.

2012, with only $1.4 million recorded in 2011 and 2012.[393] On rebuttal, PG&E claims these 2011 and 2012 costs are low because PG&E had chosen to reduce NGV infrastructure in past years, and also that "PG&E resources, originally planned for work related to CNG/LNG facilities were redeployed to pipeline safety improvement projects"[394] but that "this situation has since been remedied."[395] Neither of these post-hoc, unsupported statements support the reasonableness of PG&E's forecast, and raise questions whether PG&E would continue to redeploy such resources in the future. The actual spending levels are reasonable and should be adopted.

3.8.4 MWC 47

DRA takes no issue with PG&E's 2014 forecast of $15.1 million.[396]

3.8.5 MWC 50

MWC 50 includes "capital installation or replacement of gas facilities to improve system reliability, replace aging facilities and maintain compliance with pipeline safety regulations. These replacements include facilities that have reached the end of their useful life, facilities that have a relatively high likelihood of failure and facilities that have failed. Similar to MWC 14, PG&E's forecast includes continuing the existing MWC 50 replacement programs, but also increasing the rate of overall pipeline replacement."[397] PG&E has proposed $128.1 million in capital costs in 2014, an increase of $58.8 million over recorded 2012 costs of $69.3 million.[398] DRA proposes adoption of PG&E's 2013 forecast of $72.4 million for 2014.[399] PG&E proposes an increase of $19.8 million for main replacements from 2013 to 2014 to cover the new proposed replacement of 20 miles of post-1940 steel pipe.[400] As PG&E only replaced less than one mile of such pipe in 2011 and PG&E proposes to increase its rate more than twentyfold, and has similar

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[393] Ex. 78 (DRA-10), p.41, Table 10-24, *citing* Ex. 16 (PG&E-3-WP 07-12), p. WP 8-4.

[394] Ex. 53 (PG&E-18), p. 8-15.

[395] Ex. 53 (PG&E-18), p. 8-15.

[396] Ex. 78 (DRA-10), p. 43.

[397] Ex. 78 (DRA-10), p. 43, *citing* Ex. 14 (PG&E-3), p. 8-26.

[398] Ex. 78 (DRA-10), pp. 48, 50 & Table 10-30, *citing* Ex. 14 (PG&E-3), p. 8-26.

[399] Ex. 78 (DRA-10), p. 48.

[400] Ex. 78 (DRA-10), p. 44, Table 10-29, *citing* Ex. 14 (PG&E-3), p. 8-22.

issues as with ramping up its pipe replacement in MWC 14, the 2013 forecast, higher than the 2012 actual spending, is a reasonable forecast.[401] DRA's argument is not that PG&E will have difficulty completing the 20 miles of post-1940 pipe "clearly based on the assumption" that PG&E will complete the remaining 160 miles proposed in MWC 14, as PG&E somewhat nonsensically claims on rebuttal.[402] PG&E has not established a reasonable basis for concluding that PG&E will in fact replace the amounts of pipe it claims it will in 2014.[403]

PG&E has also failed to demonstrate the reasonableness of its request to install 3,165 new emergency valves over a three year period starting 2014, at a cost of $27.8 million. PG&E assumes that increasing the number of emergency valves and reducing the size of its emergency zones will improve its system safety in a cost effective matter even though they are in compliance with Federal standards,[404] and PG&E did not perform any study of cost-effectiveness or risk assessment of its proposal. PG&E also cannot identify the locations of the valves to be installed,[405] and again asserts that "[t]his expectation is not a requirement of forecast ratemaking."[406] It is not reasonable to forecast ratepayer reimbursement for such costly capital additions without specifying such basic information as the locations and factors used to choose such locations. Again, DRA has proposed an advice letter process that deviates from forecast ratemaking in order to account for the uncertainties of PG&E's forecast.

DRA also opposes the $2.1 million increase from 2013 to 2014 for costs of service replacement associated with a move to a three-year survey, because DRA recommends maintenance of a five-year survey.[407]

DRA recommends that the Commission mandate PG&E to submit annual reports to SED and DRA on the progress of PG&E's GPRP per D. 86-12-095.[408]

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[401] Ex. 78 (DRA-10), p. 48 and fn. 131, *citing* Ex. 14 (PG&E-3), p. 8-17.

[402] Ex. 53 (PG&E-18), p. 8-17.

[403] On rebuttal, PG&E claims to have identified post-1940 steel pipe to be replaced in all divisions except Sacramento, but provides no supporting evidence for this assertion. Ex. 53 (PG&E-18), p. 8-18.

[404] Ex. 78 (DRA-10), pp. 48-49.

[405] Ex. 78 (DRA-10), p. 49.

[406] Ex. 53 (PG&E-18), p. 8-19.

[407] Ex. 78 (DRA-10), p. 44, Table 10-29, *citing* Ex. 14 (PG&E-3), p. 8-22; p. 50.

[408] Ex. 78 (DRA-10), p. 50.

3.8.6 MWC 52

DRA takes no issue with PG&E's 2014 forecast of $0.6 million.[409]

3.8.7 MWC 2K

PG&E is forecasting a large increase in capital costs associated with High Pressure Regulator Replacement due to its new program to replace so-called "Farm Taps," small diameter regulator sets served off of a transmission pipeline.[410] Such costs, however, are properly transmission rather than distribution expenses, as they represent costs of customer access charges that have historically been treated as transmission in the Gas Accord in MWC 91, meter costs.[411] PG&E's own Leak Survey Trend Report in 2011 stated that such Farm Taps were "facilities considered transmission,"[412] and on rebuttal, PG&E appears to backtrack slightly and say that these facilities would not meet the PHMSA transmission definition.[413] PG&E also claims it could not identify how it has classified these facilities, many of which date to the 1920's and 1930's.[414] Yet some of the HPRs had vintage years listed as 2007 and 2008, and PG&E's recorded capital expenditures did not show any recorded capital expenditures for these years.[415] DRA recommends using recorded capital expenditures of $1.22 million as the forecasts for each year of 2012 to 2014 for MWC 2K.[416]

3.8.8 Advice Letter Process

DRA recommends a separate ratemaking mechanism that allows PG&E authority to request recovery of 2014 recorded capital expenditures in excess of DRA's 2014 forecast of $215.7 million but not to exceed PG&E's 2014 forecast of $331 million for MWC 14, and to request recovery of 2014 recorded capital expenditures in excess of DRA's 2014 forecast of

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[409] Ex. 78 (DRA-10), pp. 51-52 & Table 10-32.

[410] Ex. 78 (DRA-10), p. 52.

[411] *See* Tr. Vol. 15, 1527:4-17 (Bromson, Krannich).

[412] Ex. 78 (DRA-10), p. 53 and fn. 139, *citing* Ex. 15 (PG&E-3 WP 02-06), p. WP p. 6-115.

[413] Ex. 53 (PG&E-18), p. 8-24.

[414] Ex. 78 (DRA-10), p. 54 and fn. 142, *citing* Ex. 99 (DRA-10-WP), p. 140, PG&E Response to DRA-66, question 2; Tr. Vol. 15, 1523:18-1524:26 (Krannich).

[415] Ex. 78 (DRA-10), p. 55.

[416] Ex. 78 (DRA-10), p. 55

$72.439 million but not to exceed PG&E's 2014 forecast of $128.055 million for MWC 50.[417] DRA recommends that the cost to replace gas distribution pipes above DRA's 2014 forecast be included in rates only if the gas distribution pipes are actually replaced and capital expenditures are made. The exceptionally large increases requested in MWCs 14 and 50, for an unprecedented increase in the rate of pipe replacement, without basic information of the facilities to be installed for which funding is requested, require a departure from traditional forecast ratemaking. This advice letter process simply allows PG&E to recover, in early 2015, any capital expenditures in MWC 14 and 50 for pipe replacement above the level adopted by the Commission (per DRA's recommendations, hopefully) and up to the amount PG&E's have included in their application. In other words, PG&E has opportunity to recover everything they have requested, as long as they spend it. If it is so important to rapidly increase the amount of distribution pipe to be replaced, the Commission should assure that such capital costs are actually spent on new distribution pipe.

3.9 New Business and Work at the Request of Others

3.9.1 Expense

DRA takes no issue with PG&E's proposed 2014 expenses of $6.0 million in MWC LK.[418]

3.9.2 Capital Expenditures

DRA recommends $116.0 million in capital expenditures in MWCs 29 and 51 for New Business and Work at the Request of Others (NB WRO), $12 million less than PG&E's forecast of $128.0 million.[419] PG&E forecasted increase in MWC 29 from $36.7 million in costs in 2012 to $54 million in 2013 and $83 million in 2014 based on a 62.5% residential new customer growth rate from 2013 to 2014. [420] DRA disputes that current economic conditions suggest such

[417] Ex. 78 (DRA-10), pp. 39, 51.

[418] Ex. 77 (DRA-9), pp. 136-137.

[419] Ex. 78 (DRA-10), p. 56 & Table 10-35, *citing* Ex. 14 (PG&E-3), p. 9-27.

[420] Ex. 78 (DRA-10), p. 59.

a growth rate, and instead forecasts a 2014 level of $71 million, which would maintain the growth rate from 2012 recorded to the 2013 forecast for the 2013-2014 increase as well.[421]

3.10 Technical Training and Research and Development

PG&E forecasts $12.7 million for technical training activities in 2014 in MWC AB, an $8.8 million increase over PG&E's recorded spending in 2012 of $3.9 million.[422] DRA recommends adoption of PG&E's 2012 recorded amount of $3.9 million for 2014. PG&E noted that there was $12.4 million of training money embedded in other accounts in 2012,[423] which confirms a main criticism of its internal benchmark study, that "LOBs developed training to meet LOB needs without knowing what may already have been developed elsewhere and which other organizations might also need or benefit from the new materials."[424] Moreover, the study also noted that the curriculum development has "to address gaps left by 10+ years of being unable to create and maintain curriculum due to underfunding."[425] PG&E's embedded funding for training throughout its organization can be used for this purpose, in addition to the 2012 recorded level in this account. Moreover, ratepayers should not be asked to bear additional costs for such training after PG&E's woeful record of underfunding such training in the past.

For MWC GZ, which is used for identification of new or improved efforts to enhance operation, safety and efficiency within PG&E's gas operations, DRA recommends $1.5 million compared to PG&E's forecast of $2.5 million.[426] DRA proposes a 50-50 split between distribution and transmission costs, rather than PG&E's proposed 82-18 split, as PG&E lacks historical data regarding allocation of such costs between distribution and transmission from 2007-2012.[427] While PG&E criticizes DRA's proposed 50-50 as "unsubstantiated,"[428] the

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[421] *Id.*

[422] Ex. 77 (DRA-9), p. 138, Table 9-46, *citing* Ex. 14 (PG&E-3), p. 10-17, & Table 9-47, *citing* Ex. 98 (DRA-9-WP), PG&E Response to DRA-DEF10A question 1 Attachment 1, PG&E Response to DRA-108 question 4, Supp. 01, Attachment 1 (Exhibit 3, chapter 10, MWC AB, Support, $3,879,738)

[423] Ex. 77 (DRA-9), p. 140.

[424] Ex. 93C (DRA-9-Confidential), p. 139. In a September 5, 2013 e-mail, PG&E counsel Erich Lichtblau permitted DRA to discuss publicly this quote from the internal benchmark study.

[425] *Id.*

[426] Ex. 77 (DRA-9), p. 143.

[427] *Id.*

methodology PG&E used to calculate its 82-18 split was based on its own unsupported assignment of 33 different projects in of a portfolio either 100% to distribution, 100% to transmission, or a 50-50 split, and an equal weighing of the 33 projects of the portfolio even though the costs of those elements likely vary substantially.[429] Moreover, in the wake of San Bruno, it makes sense that recent efforts to improve operations would be likely on the transmission system. DRA bases its forecast of membership fees on actual fees incurred from 2010 -2012 in order to capture fluctuations.[430] Finally, of the 4 FTEs PG&E requests for 2014, DRA opposes 2 FTEs for Research and Development, as the actual R&D will be conducted by partners, and PG&E has not justified the need for 2 FTEs to "define, manage and support" those activities.[431] Instead, DRA recommends 2 FTEs to manage the third party contracts and Research and Development.

3.11 Gas Operations Technology Costs

3.11.1 Expense

PG&E forecasts $19.2 million for costs in 2014 in MWC GZ, while DRA recommends $10.9 million.[432] Recorded costs in 2011 were $0.5 million, and $6.8 million in 2012.[433] PG&E's delayed Pathfinder project has already been extended from 2014 to 2015, and DRA's request that the costs be normalized over the three-year rate case cycle is appropriate given the past delays and rate shock of this proceeding.[434] Costs for PG&E's Estimator Toolset Enhancements should also be normalized over the three-year period due the decline in forecast for 2015 and 2016.[435] DRA recommends a $0.1 million reduction to gas operations[436] and a

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[428] Ex. 53 (PG&E-18), p. 10-8.

[429] Ex. 54 (PG&E-18 V2 Appendix), p. A-213, PG&E Response to DRA-121 question 9,Attachment 1; Ex. 53 (PG&E-18), p. 10-8 and fn. 31.

[430] Ex. 77 (DRA-9), p. 144.

[431] *See* Ex. 53 (PG&E-18), pp. 10-10 to 10-11.

[432] Ex. 321 (DRA-9-E), p. 146, Table 9-51, *citing* Ex. 14 (PG&E-3), p. 11-42.

[433] Ex. 77 (DRA-9), p. 146, Table 9-52, *citing* Ex. 98 (DRA-9-WP), PG&E Response to DRA-DEF10A question 1 Attachment 1, PG&E Response to DRA-108 question 4, Supp. 01, Attachment 1

[434] Ex. 77 (DRA-9), p. 148.

[435] *Id.*, p. 149.

[436] Ex. 321 (DRA-9-E), p. 149.

$0.9 million reduction in mobile expenses[437] based on reduced capital expenditure recommendations as set forth below in Section 3.11.2.

3.11.2 Capital Expenditures

PG&E forecasts $43.7 million in capital expenditures in 2014 for Information Technology (IT) projects for gas operations. DRA proposes $13.9 million.[438]

PG&E has proposed a new Pathfinder Project to convert existing legacy and paper-based systems to the SAP and Geographic Information System (GIS).[439] In the previous GRC, PG&E forecasted capital spending for 2011 of $14.3 million for its base GIS project started in 2008, the Automated Mapping and Facilities Management (AM/FM) project.[440] But PG&E stopped the project in December 2010,[441] subsequent to reaching a settlement agreement for the 2011 GRC, and transitioned it into the Pathfinder Project, arguing that the AM/FM project was not sufficiently expansive. PG&E recorded $5.7 million in capital spending in 2011, well less than its forecast of $14.3 million.[442] PG&E forecasted $14.4 million in 2012 for Pathfinder, and only recorded $3.1 million.[443] Given this consistent pattern of underspending forecasts on this project, DRA recommends that the 2012 recorded level of spending be adopted as the 2014 forecast. PG&E has not demonstrated that it will commit the forecasted resources to Pathfinder in 2014, and as noted above in Section 3.11.1, the program can be spread over a longer time period.

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[437] Ex. 77 (DRA-9), p. 150.

[438] Ex. 314 (DRA-10-E), p. 61, Table 10-41, *citing* Ex. 14 (PG&E-3), p. 11-43; Ex. 78 (DRA-10), p. 64, Table 10-43, *citing* Ex. 16 (PG&E-3 WP Vol 7-12), pp. WP 11-31, WP 11-35, WP 11-40, WP 11-45, WP 11-49, WP 11-52, WP 11-55, WP 11-59, WP 11-64, WP 11-69, WP 11-73, WP 11-78, WP 11-82, WP 11-86, WP11-90, WP 11-93, WP 11-101, &WP 11-104.

[439] Ex. 78 (DRA-10), p. 65.

[440] *Id.*

[441] Ex. 78 (DRA-10), p. 66 and fn. 177, *citing* Ex. 14 (PG&E-3), p. 3-10.

[442] Ex. 78 (DRA-10), p. 67 and Table 10-45, *citing* Ex. 99 (DRA-10-WP), pp. 175-179, PG&E response to DRA-112, question 2.

[443] Ex. 78 (DRA-10), p. 67 and fn. 183, *citing* Ex. . 99 (DRA-10-WP), pp. 175-179, PG&E response to DRA-112, question 2.

PG&E forecasts $3.4 million in 2014 for the Estimator Toolset Enhancement Projects. DRA recommends $2.8 million, a 14% reduction, consistent with DRA's global recommendation to reduce PG&E's forecasts of IT projects calculated by the "Concept Estimate Tool" by 14%.[444]

PG&E's response to DRA's recommendation references its arguments against DRA's proposed 14% reduction.[445] DRA's recommendations of $0.9 million for public safety initiatives, $1.4 million for New Regulatory Reporting Requirements, $2.0 million for the Gas Control Center Radio System, $0.7 million for the Field Automation System Upgrade Project, and $2.2 million for Testing and Conforming Applications to Vendor Upgrades are similarly based on this 14% reduction.[446] DRA recommends denial of PG&E's request for $8 million for backup radios for all of its Gas Service Representatives as not necessary. PG&E's GSRs, dispatchers, and supervisors have several options available for communication which include desk top computers, laptops, landline telephones, email, Mobile-Connect laptops in vehicles, in addition to mobile telephones for voice and text communications. PG&E has not performed any analysis regarding the quality of cellular coverage and the problems the cellular coverage has affected PG&E.[447] PG&E's Radio Network Refresh Project, scheduled to be completed this year and for which PG&E already recorded $56 million in capital expenditures from 2009-2012, already provides radio communications to its departments and field crews in the Gas and Electric Transmission and Distribution..[448] PG&E's request should be denied.

PG&E is forecasting $1.5 million in capital expenditures in 2014 for Mobile for Long-Cycle Work, and DRA recommends $1.0 million.[449] PG&E proposed a three-year program starting in 2014 that would escalate and cost $6.3 million total.[450] Of those costs about $1.8 million are for the installation of mobile facilities and software in 196 trucks, and the remaining

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[444] *See* Section 7.8, *infra*.

[445] Ex. 53 (PG&E-18), p. 11-19 and fn. 48, *citing* Ex. 60 (PG&E-22), pp. 8-38 to 8-42.

[446] *See* Ex. 78 (DRA-10), pp. 71, 72, 75-76, 83-84.

[447] Ex. 78 (DRA-10), pp. 73-74.

[448] Ex. 78 (DRA-10), p. 73 and fn. 197, *citing* Ex. 99 (DRA-10-WP), pp. 184-189, PG&E's response to DRA-116, question 1.

[449] Ex. 78 (DRA-10), p. 78, Table 10-54, *citing* Ex. 14 (PG&E-3), p. 11-33.

[450] Ex. 78 (DRA-10), p. 78; Tr. Vol. 16, 1621:22-1622:7 (Whelan); Ex. 14 (PG&E-3), p. 11-33, Table 11-15.

$4.6 million in capital costs is for software modifications to SAP, FAS, GIS, and Ventyx Systems.[451] DRA's proposal included $1.0 million for such software modifications.[452] On rebuttal testimony, PG&E states it provided a detailed discussion of these costs to DRA and references PG&E's response to Data Request DRA-188-010c, but PG&E did not include this response in Ex. 54 as represented.[453] PG&E's request for such extensive software modification costs is excessive and unsupported.

PG&E is forecasting $3.0 million in capital expenditures in 2014 for Mobile for Short-Cycle Work, and DRA recommends $0.6 million.[454] PG&E proposed a five-year program from 2012-2016 of a total cost of $12.5 million.[455] Of those costs about $1.3 million are for the installation of mobile facilities and software in 196 trucks, and the remaining $11.2 million in capital costs is for software modifications to SAP, FAS, GIS, and Ventyx Systems.[456] DRA's proposal included $1.0 million for such software modifications.[457] On rebuttal testimony, PG&E merely referenced a summary table in its opening testimony regarding these costs,[458] and the workpapers referenced in that table do not break down the $11.2 million in capital costs for software modifications.[459] PG&E's request for such extensive software modification costs is excessive and unsupported.

PG&E proposes $1.8 million in 2014 capital expenditures for mobile devices in multi-person work crews,[460] devices for employees in addition to having one device per job site per vehicle "for when the crew is split into a smaller group or when a crew member has been

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[451] Tr. Vol. 16, 1622:22-1624:22 (Whelan).

[452] Ex. 78 (DRA-10), p. 78.

[453] Ex. 53 (PG&E-18), p. 11-24 and fn. 54. *See* Ex. 54 (PG&E-18 V2) p. ii (Data Request Index).

[454] Ex. 78 (DRA-10), p. 80, Table 10-55, *citing* Ex. 14 (PG&E-3), p. 11-35.

[455] Ex. 78 (DRA-10) and fn. 214, *citing* Ex. 14 (PG&E-3), p. 11-35.

[456] Tr. Vol. 16, 1625:7-1626:10, 1627:24-1628:7 (Whelan).

[457] Ex. 78 (DRA-10), pp. 79-80.

[458] Ex. 53 (PG&E-18), p. 11-25 and fn. 70, *citing* Ex. 14 (PG&E-3), p, 11-35, Table 11-16.

[459] Ex. 14 (PG&E-3), p, 11-35, Table 11-16, *citing* Ex. 16 (PG&E-3 WP 07-12), p. WP 11-19, Line 20; *see* pp. WP 11-80 to 11-82.

[460] Ex. 78 (DRA-10), p. 81.

temporarily rotated into a supervisor role."[461] DRA recommends no funding in 2014 for this project, as with the expensive roll-out of the mobile devices as above, the need for additional devices is premature. PG&E should wait until the long-cycle and short-cycle mobile devices are installed before proposing additional devices.

PG&E proposes $1.9 million in 2014 capital expenditures in order to improve the purported fit for need of current mobile devices in the field.[462] DRA recommends no funding, as PG&E has not established that improving current devices in the field should receive such a priority while the current devices are adequate. PG&E also states in rebuttal testimony that it will repurpose the current devices, [463] both conceding that current devices still are useful and have value, but PG&E does not provide for any offsets for the savings of repurposing such devices. Under these circumstances, PG&E's request for new funding in the test year should be denied.

3.12 Gas Operations Building Projects, AGA Fees and PAS 55 Certification

3.12.1 Expense

PG&E requests $7.4 million in expense in support of the Gas Operations Building Projects, American Gas Association (AGA) Dues and Publicly Available Standard (PAS) certification. DRA recommends $2.5 million for MWC AB. The forecast consists of $2.1 million for the leasing cost of the Gas Operations Headquarters Building, zero for the Gas Training Center, $300,000 for expenses associated with Major Projects, zero for expenses related to Minor Projects, and $0.2 million for a three-year normalized expense amount for PAS 55 Certification Support.[464]

DRA recommends zero expenses for Gas Training Center Building based on the recommendation below in Section 3.12.2 on capital that no funding be provided for this project. PG&E proposes $1.0 million in major projects, mostly for relocation of employees and demolition of existing furniture. DRA recommends $0.3 million for major projects because

[461] Ex. 53 (PG&E-18), p. 11-26.

[462] Ex. 78 (DRA-10), p. 82; Ex. 53 (PG&E-18), p. 11-29.

[463] Ex. 53 (PG&E-18), p. 11-29.

[464] Ex. 77 (DRA-9), p. 150, 155-156.

these are one-time expenses that could be normalized over the rate case period. DRA recommends zero for minor project costs, because none of these projects, which include very routine tasks, are new activities, but rather typical maintenance activities.[465] PG&E could not provide annual expenses in past years for such items because they did not track such costs separately and embedded such costs in other MWCs.[466]

3.12.2 Capital Expenditures

PG&E forecasts $61.5 million in capital expenditures for 2014,[467] and DRA recommends $15.9 million.[468] The majority of this difference is due to DRA's recommendation to deny $40.9 million for a new gas training center building.[469] PG&E's existing gas distribution training facilities have been sufficient for effective training for over 20 years, and for tasks that cannot be accomplished at such locations, PG&E can dispatch employees to on-site locations or third-party training.[470] PG&E believes its existing facilities are deficient in such areas as Transmission Training – not Distribution Training – although PG&E allocates only 19.35% of the overall costs of the facility to transmission.[471] Exercises with emergency responders do not require a central facility and can be held throughout PG&E's service territory.[472] If indeed the Commission does approve this facility, a larger allocation of costs to transmission is warranted because of the explicitly greater benefits to transmission safety than distribution safety.

PG&E initially proposed $3.1 million in capital costs in 2014 associated with its new consolidated headquarters building in San Ramon, and then updated that request to $2.5 million in an errata based on allocating 19.35% of the total to transmission, and 80.65% to

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[465] Ex. 77 (DRA-9), p. 154 and fn. 458, *citing* Ex. 98 (DRA-9-WP), PG&E response to DRA-156, question 4.

[466] Ex. 77 (DRA-9), pp. 154-155 and fns. 458 & 459, *citing* Ex. 98 (DRA-9-WP), PG&E response to DRA-156, question 4.

[467] Ex. 78 (DRA-10), p. 85, *citing* Ex. 14 (PG&E-3), p. 12-15.

[468] Tr. Vol. 28, 3710:20-28 (Chia); *see* Ex. 78 (DRA-10), p. 85 & Ex. 314 (DRA-10-E), p. 86.

[469] Ex. 78 (DRA-10), p. 89.

[470] Ex. 78 (DRA-10), p. 90.

[471] *See* Ex. 78 (DRA-10), pp. 91-92 and fn. 247, *citing* Ex. 99 (DRA-10-WP), pp. 162-171, PG&E response to DRA-104, question 1.

[472] Ex. 78 (DRA-10), p. 92.

distribution.[473] DRA recommends this updated request. DRA similarly recommends $6.2 million for the Antioch Service Center,[474] and $3.7 million for the San Carlos Service Center Building Addition[475] based on updated PG&E totals allocating some costs to transmission.

For minor projects, PG&E forecasts $2.2 million broken down into routine items such as chairs, tables, workstations, painting allowances, and repair allowances.[476] PG&E recorded $0.5 million in capital expenses in 2011, but none for minor projects, and all for major projects.[477] PG&E otherwise has no recorded 2007 to 2012 data for this category broken down between minor and major projects. DRA recommends using a 50% proxy as an approximation of the split between minor and major projects, of the actual 2011 total costs of $0.5 million.[478]

4 ELECTRIC DISTRIBUTION

4.1 Policy and Introduction

Throughout this GRC Application, and particularly in its requests for Electric Distribution Operations, PG&E is seeking funding for projects for which it was granted funding in previous GRCs. PG&E's explanation is that, "[a]s with any business, unexpected needs arise, and it is necessary to reprioritize and shift funds and resources to perform work that was not included in the prior forecast."[479] This does not explain, however, where the money went, nor does it justify repeatedly asking ratepayers to fund the same project.

This is particularly troubling in connection with PG&E's capital requests.

Capital expenditures are cumulative in nature. Expenditures made during one year are added to expenditures that were made in previous years. Therefore, DRA must analyze all of the proposed capital expenditures occurring from the end of the last recorded year (2011) provided

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[473] Ex. 78 (DRA-10), p. 87 and fn. 232, *citing* Ex. 49 (PG&E-Errata), p. 14-267.

[474] Ex. 78 (DRA-10), p. 94 and fn. 254, *citing* Ex. 49 (PG&E-Errata), p. 14-264.

[475] Ex. 78 (DRA-10), pp. 96-97 and fn. 265, *citing* Ex. 99 (DRA-10-WP), p. 195, PG&E response to DRA-136, question 7, and Table 10-71, *citing* Ex. 49 (PG&E-Errata), p. 14-267.

[476] *See* Ex. 53 (PG&E-18), p. 12-29 and fn. 125, *citing* Ex. 54 (PG&E-18 Vol 2), pp. A-216 to A-217, PG&E response to DRA-156 question 4 and attachment 1.

[477] Ex. 78 (DRA-10), p. 98 and fn. 268, *citing* Ex. 14 (PG&E 3), p. 12-14.

[478] Ex. 78 (DRA-10), pp. 98-99, Ex. 314 (DRA-10-E), p. 99.

[479] Ex. 55 (PG&E-19), p. 1-12

by PG&E in its Application up through the end of the test year (2014). Proposed capital expenditures or additions for the attrition years (2015 and 2016) are also addressed by DRA, but are discussed in Section 12, Post Test-Year Ratemaking, below. Ideally, DRA tries to obtain an additional recorded year of plant data (in this case 2012) in order to eliminate one year of estimating uncertainty. Fortunately, for this GRC, DRA was able to obtain recorded 2012 capital expenditure data from PG&E.

Capital expenditures are especially important because utility management has discretion to defer them to later years. While DRA understands that deferrals happen occasionally, in many cases, PG&E's deferral of capital expenditures are ongoing.

PG&E states that from 2007 to 2012, it spent more on capital than the imputed GRC amount for the Electric Operations line of business.[480] PG&E does not state whether the overspending occurred every year of that period, or whether it is adding together the recorded expenditures for all of the years, and comparing that total to the sum of what was authorized. Whichever methodology PG&E used is of little consequence. PG&E has, in several instances, repeatedly deferred capital expenditures that had previously been authorized.

While utility managers are allowed to transfer/spend company funds as they see fit, that does not equate to an automatic acceptance by the regulatory agency of every managerial decision that is made. As recent Commission decisions have ruled, utilities are usually not allowed a second opportunity to recover expenses that were previously authorized but subsequently deferred. The same should hold true for deferred capital expenditures. It is inappropriate for a utility to continually defer authorized capital expenditures away from capital projects deemed necessary by the utility, and then seek recovery of the same projects in a later proceeding.

When necessary authorized expenditures are deferred, PG&E appears to be circumventing the fundamental principle of test year ratemaking stated above (i.e., that utilities run the risk of spending more than what they were authorized if unexpected and/or higher than expected expenses or capital additions occur). Taken to an extreme, it is hypothetically possible for a utility to never earn less than what it was authorized; if expenses or capital costs are higher than forecasted, it could theoretically simply defer sufficient expenditures, no matter how

[480] Ex. 17 (PG&E-4), p. 1-23, lines 3-4.

essential they may be, to offset the higher expenses/additions. This type of ratemaking philosophy skews the GRC process in the utility's favor (i.e., a utility is free to retain unspent revenues when actual costs are less than authorized, but never spends more than authorized because it is able to defer expense/plant expenditures that exceed what was forecasted). This practice should not be condoned by the Commission.

PG&E has, in several instances, repeatedly deferred capital expenditures that had previously been authorized. In the 2011 GRC, PG&E was forthcoming in stating:

> In an effort to remain within the capital and expense expenditure levels imputed from the 2007 GRC Settlement Agreement, PG&E adjusted work where possible by focusing on work in higher priority categories.[481]

The fact that PG&E claims that it actually spent more than was authorized does not diminish the fact that it engaged in a practice that was designed to ameliorate its higher than expected capital expenditures. As stated previously, expenditures that are higher than authorized are simply the naturally occurring result of test year ratemaking, and the utility will ultimately earn a return on those investments in subsequent rate cases.

Historically, Commission decisions have ruled that utilities should not be permitted to recover expenses that have previously been authorized but were deferred. Recent Commission decisions are starting to take the same position regarding deferred capital expenditures, echoing DRA's concerns expressed above. In the decision for SCE's Test Year 2003 GRC, the Commission discussed the need to consider SCE's deferral of pole inspections and stated that:

> This is necessary to ensure that ratepayers are not required to pay a second time for activities explicitly authorized by the Commission in the past …[482]

Later, in the same decision, the Commission stated:

> Based on the foregoing, we will reduce SCE's capital forecast for pole replacements by $3.447 million (68,934 intrusive inspections

[481] Ex. 75 (DRA-7), p. 12, footnote 12 citing PG&E 2011 GRC (A.09-12-020), Exhibit PG&E-3, pp. 1-35, lines 10 through 13.

[482] D.04-07-022, p. 106.

> that were funded by ratepayers but not performed by SCE times $50 per missed inspection).[483]

In the Test Year 2007 PG&E GRC decision, the Commission stated:

> More recently, the Commission disallowed $1.4 million in annual expenses and $3.4 million in capital costs that SCE requested for deferred pole maintenance, stating that "ratepayers should not be required to pay twice for the same authorized expense."[484]

Later, in the same decision, the Commission stated:

> The Commission has repeatedly held that it is unjust and unreasonable to make ratepayers pay a second time for activities explicitly authorized by the Commission in the past. Here, there is no dispute that PG&E received funding for lead paint and PCB abatement in its prior GRC proceeding, and that PG&E seeks funding for these activities a second time in the current proceeding. … In order to find that the Settlement Agreement is consistent with the law, which includes adherence to long-established Commission precedent, we must be satisfied that all of PG&E's lead paint and PCB abatement costs are excluded from the O&M expenses adopted by the Settlement.[485]

In D.09-03-025, SCE's Test Year 2009 GRC, the Commission states the following:

> In this proceeding, SCE seeks additional funds for activities explicitly authorized by the Commission in the past. SCE seeks funds to redress maintenance postponed due to unanticipated load and customer growth in 2006-2007. To address this unforeseen customer and load growth, SCE diverted millions of dollars in capital replacements away from its Infrastructure Replacement project … In the past, we have found circumstances, such as the unanticipated scope of Year 2000 (Y2K) projects, to justify deferral of certain maintenance work. The circumstances surrounding Y2K and the related Y2K projects were one-time events and, as such, unique. In contrast, we do not find customer and load growth, even when unanticipated, to create unique circumstances. Load growth and customer growth are routine aspects of any rate case. If the adopted forecast overestimates expenses we do not ask a utility to return funds to ratepayers. Similarly, if an adopted forecast underestimates expenses, we do

[483] D.04-07-022, p. 110.

[484] D.07-03-044, p. 93.

[485] D.07-03-044, pp. 94 and 95.

> not go back and give the utility funds to complete projects that should have been addressed in the prior GRC cycle. In short, errors in forecasting occur and we do not go back and fix these errors. Consistent with our policy regarding deferred maintenance, in certain instances in this decision, we adopt reductions to SCE's forecast for operation & maintenance and capital expenditures to reflect our finding that unanticipated load and customer growth does not justify SCE's decision to, among other things, defer maintenance.[486]

Lastly, in the most recent SCE GRC decision for Test Year 2012, the Commission makes the following statement regarding SCE's repeated attempts to obtain authorization for capital projects that had been previously deferred:

> SCE was authorized $3.9 million in its 2006 GRC to fund a new administration building, but said it diverted these funds to meet unforeseen load growth during that time period. In 2009, SCE's request for $4.92 million for the administration building project was denied because of the previously approved funding. SCE points out that, on the merits of the project, TURN admits that the current offices are not sufficient to house even what TURN deems electric-only employees.
>
> When the Commission rejected the predecessor project in 2009, it was because it viewed deferred funds for unexpected load growth and customer growth as routine, within SCE's discretion, and not subject to re-funding in the next GRC. The facts are essentially the same, despite SCE's repackaging of the project. Moreover, approximately $2.3 million was added to the Main Building project as a result of the rejection of the Administration building in the 2009 GRC. Thus, the overall request by SCE for its re-configured Administration construction is almost $7.8 million.
> We agree with TURN that these costs appear to be excessive and growing as a result of SCE's management making discretionary choices to not use authorized funds for the identified projects and to keep coming back to ratepayers for more. Accordingly, the Commission finds it reasonable to exclude the entire capital request.[487]

[486] D.09-03-025, pp. 3 through 5.

[487] D.12-11-051, mimeo., pp. 89 and 90.

It is important to keep in mind the fundamental policy by which all California utilities must abide, namely, the obligation to serve. This obligation can only be met if necessary capital projects are undertaken. Conversely, that obligation cannot be met when necessary capital projects are deferred. Whether those projects were previously authorized in prior decisions, or whether they occurred unexpectedly is immaterial – they all must be done. Equally important is the fact that PG&E's customers should not be required to pay for the same project twice.

Not surprisingly, PG&E attempts to refute DRA's deferral recommendations. In Rebuttal, PG&E appears to base its criticism of DRA on the following three areas:

- PG&E develops its best GRC forecast based on information available to it at the time the GRC is developed, which sometimes means that forecasts are made nearly two years prior to the beginning of the 3-year GRC cycle.
- Because unexpected needs arise, it is necessary to reprioritize and shift funds and resources to perform work that was not included in prior GRC forecasts.
- PG&E's ratepayers are not really paying twice for capital expenditures that were previously authorized by the Commission but were deferred.[488]

In Rebuttal, PG&E discusses how it is inevitable that forecasts for multiple types of work, made several years before the projects are actually undertaken, will not be perfect.[489] Apparently, this discussion is meant to suggest that PG&E is engaging in nothing more than "fine tuning" its capital expenditures to eliminate projects that were ultimately deemed to be unnecessary.

DRA does not dispute PG&E's statement, but believes that it misses the entire point of DRA criticism of PG&E's deferral policy. The deferral examples discussed by DRA are not instances of PG&E making isolated capital changes to meet unexpected changes to its forecast. Rather, as shown in detail by DRA, PG&E has engaged in in a systematic pattern of continual deferrals that stretch over several rate case cycles. More importantly, PG&E's own statements clearly show that it is not simply switching authorized expenditures from an area that does not require them to an area that does; these are cases of PG&E not spending authorized expenditures for needed projects so as to fund other projects deemed to be a higher priority. As stated

[488] Ex. 55 (PG&E-19), p. 1-11.

[489] Ex. 55 (PG&E-19), p. 1-11

previously, this is nothing more than an attempt to circumvent the GRC process by keeping unspent revenues when actual costs are less than authorized, but never spending more than authorized because it defers capital projects when expenditures might exceed what was authorized.

In its Rebuttal, PG&E also says that its management has a duty to prioritize its spending as circumstances change to ensure that customer needs are responsibly addressed.[490] PG&E further alleges that it must be able to shift funds to address emerging issues such as cyber security.[491] Lastly, PG&E suggests that it is necessary to reprioritize and shift funds when it ultimately is determined that projects originally included in the GRC forecast are not ready to move forward.[492]

PG&E mischaracterizes DRA's testimony. First, DRA does agree with PG&E that it has a duty to ensure that customer needs are responsibly addressed. However, DRA does not believe that deferring needed capital projects is any way to adequately address customer needs. A utility should not "prioritize" (i.e. pick and choose) it's necessary projects; it should do all projects that are required. By definition, the very act of deferring needed projects means that some things that should be undertaken are not. That is clearly not the way to provide safe and reliable service. If PG&E elects to defer a needed project that has been authorized by the Commission, ratepayers should not be required to fund the project a second time if PG&E seeks to include it in a subsequent proceeding.

Second, nothing in DRA's testimony suggests that PG&E should ignore emerging issues. To the contrary, DRA is recommending that PG&E undertake all of the necessary programs authorized in previous GRCs along with any additional unexpected projects (such as emerging issues like cyber security) that are required to maintain reliable service.

Third, DRA agrees that it makes little sense to begin a capital project if the project is not ready to move forward. On the other hand, DRA does not agree that PG&E (or any utility) should defer needed capital projects simply because they would exceed their original budget forecasts. Moreover, several ongoing deferral examples DRA noted, such as pole replacements

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[490] Ex. 55 (PG&E-19), p. 1-12, lines 4 through 7.

[491] Ex. 55 (PG&E-19), p. 1-12, lines 7 through 9.

[492] Ex. 55 (PG&E-19), p. 1-12, lines 9 through 11.

and underground cable replacements do not suffer from either unexpected slowdowns or unexpected cost increases. As DRA noted in its testimony, PG&E readily admits that the ongoing deferrals of authorized pole replacements and underground cable replacements were simply due to the reallocation of funds to higher priority work.[493]

Finally in Rebuttal, PG&E argues that PG&E's ratepayers are not really paying twice for capital expenditures that were previously authorized by the Commission; ratepayers actually paid for other important work that arose since the preparation of the prior forecast.[494] DRA agrees that the deferred projects have not been included in rate base, so in that sense, ratepayers have not previously paid for these projects. However, when the Commission determined the authorized revenue requirements for PG&E in prior GRCs, those determinations were based on capital projects that had been found reasonable, including those projects that were ultimately deferred. There is no way of knowing whether the Commission would have found reasonable (and authorized funding for) the projects that were substituted for those that were deferred. Therefore, in a ratemaking sense, PG&E's customers have indeed already paid for those deferred projects.

In its Rebuttal, the California Coalition of Utility Employees (CUE) raises a similar issue. CUE asserts that it is incorrect to say that, absent a balancing account, any specific work is "funded" in a GRC.[495] As discussed in the previous paragraph, DRA would point out that the determination of a revenue requirement inherently assumes that certain levels of capital additions will occur, and that those capital levels were found to be reasonable and were authorized only after extensive litigation of specific projects occurred during the GRC process.

In summary, nothing in PG&E's or CUE's Rebuttal causes DRA to change its position that:

- Recent Commission decisions have prohibited utilities from seeking funding a second time for projects that were previously approved but were deferred.
- Ratepayers should not have to pay for capital projects twice.

[493] Ex. 75 (DRA-7), pp. 12-13.

[494] Ex. 55 (PG&E-19), p. 1-12.

[495] Ex. 148 (CUE-3), p. 3.

- A utility's obligation to serve requires that it undertake all authorized projects that are needed, in addition to any unanticipated projects that are needed.

The areas where DRA disputes PG&E's Electric Distribution Operations forecasts and the reasons for the disputes are discussed below.

4.2 Electric Operations Technology

4.2.1 Expense

The Expenses for PG&E's Electric Operations Technology fall under Major Work Category (MWC) JV.[496] There are twelve different projects for the expenses under MWC JV.[497] These are:

1. Emergency Response Technology;
2. Data Historian for Electric Distribution;
3. Outage Reporting and Analysis System;
4. Electric Distribution Geographic Information System/Asset Management (ED GIS/AM);
5. Asset Risk Management Tool for Public Safety;
6. Graphic Work Design (GWD) Tools;
7. Capital Asset and Expense Planning System (CAEPS) Enhancements;
8. SAP Work Management Enhancements (plant maintenance module);
9. Project Management and Reporting Toolset Enhancement;
10. Customer Connections Online (CCO) Tools;
11. Workforce Mobilization by Field Crew or Work Type; and
12. Work Scheduling and Dispatch System Consolidation.

PG&E's TY 2014 forecast for these projects is $12.075 million.[498] DRA recommends the Commission adopt a forecast of $4.675 million.[499] DRA opposes any ratepayer funding for four

[496] DRA's recommendations for MWC JV correlate with the similar project funding found in Exhibit 76 (DRA-8). This will be further discussed under the capital expenses

[497] Ex. 18 (PG&E-4 workpapers), p. WP 2-13.

[498] Ex. 18 (PG&E-4 workpapers), p. WP 1-8.

[499] Ex. 73 (DRA-5), pp. 7-13.

of the projects, recommends reduced funding for seven of the projects and developed its own estimate for one.[500]

PG&E developed most of its TY 2014 forecasts for MWC JV using an application referred to as the "Concept Estimating Tool."[501] PG&E's forecast for MWC JV is 454.40% over the 2011 expenses. In PG&E's TY 2011 GRC, it forecasted expenses of $4.3 million[502] for MWC JV, of which PG&E actually spent only $2.2 million.[503] PG&E's $12.075 million forecast is excessive and not justified by traditional ratemaking principles or on any other basis.

As the Commission has stated, "forecasting methodologies are an integral part of developing the many different cost forecasts."[504] Often, in GRCs, the dispute among parties is whether to use historical averages, most recent recorded data or a combination thereof.[505] Here, PG&E has unilaterally decided that "past expenditures are not relevant" to what PG&E is forecasting for Major Work Category JV.[506] PG&E acknowledges that "it did not have significant expenditures in the years leading up to 2011" for this Major Work Category, and now says that its proposal to increase ratepayer funding by 454% is because it"…needs to implement several key technology improvements to continue to provide safe, reliable and affordable service in the future."[507]

It is troubling that PG&E itself considers so many of its systems simultaneously out-of-date, inefficient, or unable to support current requirements, and that PG&E is only now choosing to update them. System and software updates are routine maintenance activities that ratepayers continually fund and PG&E should have embedded costs for these IT projects. DRA does not oppose additional funding for projects which will bring efficiency to PG&E and value to ratepayers, especially projects that focus on ratepayer cost savings, reliability, and safety.

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[500] Ex. 73 (DRA-5), pp. 7-13.

[501] Ex. 73 (DRA-5), p. 6.

[502] Ex. 17 (PG&E-4), p. 2-6, lines 5-8.

[503] Ex. 17 (PG&E-4), p. 2-6, lines 5-8.

[504] D.13-05-010, mimeo, p. 14; 2013 Cal. PUC LEXIS 227 at *20.

[505] *See, e.g.*, D. 13-05-010, mimeo, pp. 19-20.

[506] 17 RT 1860: 1-8, PG&E/Dasso.

[507] Ex. 55 (PG&E-19), p. 2-6.

PG&E, however, has provided minimal cost benefit analyses to justify its proposed MWC JV projects, instead offering only an estimated timeframe for when that analysis would be done.[508]

PG&E breaks down MWC JV into 12 subsets each of which may seem to have a low revenue requirement, but collectively, total nearly $12.1 million. DRA's recommendations are set forth below.

4.2.1.1 Emergency Response Technology

PG&E is requesting $0.267 million for Emergency Response Technology. PG&E says the project will upgrade IT infrastructure and telecommunications in Electric Distribution Storm Rooms (DSRs) to allow better coordination between PG&E's emergency response facilities during unplanned outages.[509] DRA's corresponding test year estimate is $0.230 million.[510] DRA does not oppose the project, but has concerns about PG&E's Concept Estimating Tool, as described in more detail in Section 7 of this Opening Brief. Consistent with DRA's recommendations there, DRA reduced forecasted expenses for the Emergency Response Technology project by 14%.[511]

4.2.1.2 Data Historian for Electric Distribution

PG&E is requesting $0.206 million for its Data Historian project.[512] PG&E says that the Data Historian software provides central data archiving and analysis for time series data from PG&E's Supervisory Control and Data Acquisition (SCADA) system. This project will replace PG&E's "legacy data historian software application" with a commercially available and industry-standard data historian application. As discussed in connection with PG&E's proposed Capital expenditures, DRA recommends that the Commission reject PG&E's request for funding of the Data Historian project. Therefore, DRA recommends that the Commission also reject the associated project expenses.[513]

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[508] Ex. 55 (PG&E-17), p. 2-9.

[509] Ex. 18 (PG&E-4 workpapers), p. WP 2-23.

[510] Ex. 73 (DRA-5), p. 7-8.

[511] Ex. 73 (DRA-5) p. 16.

[512] Ex. 18 (PG&E-4 workpapers), p. WP 2-13.

[513] Ex. 73 (DRA-5), p. 8 citing Ex. 76 (DRA-8).

4.2.1.3 Outage Reporting and Analysis System

PG&E is requesting $0.362 million for Outage Reporting & Analysis System Replacement.[514] The project will replace legacy tools and manual processes used to record outage data and monitor reliability metrics with an automated system that can more efficiently perform these processes. The new project will also integrate newly available SmartMeter and SCADA data. DRA's corresponding test year estimate is $0.311 million. DRA does not oppose the project, but has concerns about PG&E's Concept Estimating Tool, as described in more detail in Section 7 of this Opening Brief. Consistent with DRA's recommendations there, DRA reduced forecasted expenses for this project by 14%.[515]

4.2.1.4 Electric Distribution Geographic Information System/Asset Management (ED GIS/AM)

PG&E is requesting $1.830 million for the Electric Distribution Geographic Information System/Asset Management (ED GIS/AM) project.[516] PG&E says the project will convert PG&E's electric distribution asset data into a single, integrated GIS system, as opposed to the isolated legacy systems, which PG&E currently uses to record its asset data. The ED/GIS project is a continuation of the Automated Mapping and Facilities Management (AM/FM) project. According to PG&E, the AM/FM project "completed upgrades to legacy systems and map alignment work before the project was completed in favor of the new integrated GIS/SAP approach envisioned for this project."[517]

Since PG&E says it suspended the AM/FM project in 2011, DRA asked PG&E why it continues to spend money on a project that was brought to a close. PG&E's response was that it:

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[514] Ex. 18 (PG&E-4 workpapers), p. WP 2-33.

[515] Ex. 73 (DRA-5) p. 16.

[516] Ex. 18 (PG&E-4 workpapers), p. WP, 2-13.

[517] Ex. 18 (PG&E-4 workpapers), p. WP 2-51.

> …suspended work on the AM/FM project in 2011 to assess the effectiveness of the project. The assessment determined that a more robust system was needed and original AM/FM project was closed in September 2011. The AM/FM project was re-launched as separate GIS/AM projects for Electric Distribution, Gas Distribution, Electric Transmission and Gas Transmission. The forecast amounts referenced in footnote 25 (Exhibit (PG&E-4), page 2-26) were included in PG&E's 2011 GRC forecast and used to cover the cost of the initial phase of the AM/FM (or Base GIS) project through 2011 and will be allocated to the new ED GIS/AM project and the gas distribution GIS project also known as Pathfinder.[518]

DRA opposes additional funding for the ED/GIS project, which previously received ratepayer funding under a different project name. The reallocation of embedded ratepayer funds from the AM/FM project to the ED GIS/AM project should be sufficient to cover subsequent phases of the project.[519]

4.2.1.5 Asset Risk Management Tool for Public Safety

PG&E is requesting $0.349 million for its Asset Risk Management Tool for Public Safety.[520] PG&E says the tool will allow PG&E to systematically identify high-risk locations within its service area, interpret results, and plan mitigation activities.[521] DRA's corresponding test year estimate is $0.300 million. Due to its concerns about PG&E's Concept Estimating Tool, DRA reduced forecasted expenses for the project by 14% as recommended in Section 7, below in this Opening Brief.

4.2.1.6 Graphic Work Design (GWD) Tools

PG&E is requesting $0.801 million for the Graphic Work Designs (GWD) project.[522] The project will replace PG&E's current construction design and estimating toolset with new graphics-based construction visualization and estimation software.[523] DRA's corresponding test year estimate is $0.689 million. Due to its concerns about PG&E's Concept Estimating Tool,

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[518] Ex. 73 (DRA-5), p. 9, citing DRA-067-EJ1 Q/A 9f.

[519] Ex. 73 (DRA-5), p. 10.

[520] Ex. 18 (PG&E-4 workpapers), p. WP 2-58.

[521] Ex. 18 (PG&E-4 workpapers), p. WP 2-57.

[522] Ex. 18 (PG&E-4), p. WP 2-64.

[523] Ex. 18 (PG&E-4 workpaper), p. WP 2-62.

DRA reduced forecasted expenses for the project by 14% as recommended in Section 7, below in this Opening Brief.

4.2.1.7 Capital Asset and Expense Planning System (CAEPS) Enhancements

PG&E is requesting $0.141 million for the second phase of the Capital Asset and Expense Planning (CAEPS) Enhancements.[524] The tool will facilitate planning, budgeting, staffing, and monitoring work by using historic costs per unit of work. DRA's corresponding test year estimate is $0.121 million. Due to its concerns about PG&E's Concept Estimating Tool, DRA reduced forecasted expenses for the project by 14% as recommended in Section 7, below in this Opening Brief.

4.2.1.8 SAP Work Management Enhancements (Plant Maintenance Module) (a)

PG&E is requesting $0.751 million for SAP Work Management Enhancements.[525] PG&E says the funding will help bring different departments onto the SAP platform, which facilitates work order management processes.[526] DRA's corresponding test year estimate is $0.645 million. Due to its concerns about PG&E's Concept Estimating Tool, DRA reduced forecasted expenses for the project by 14% as recommended in Section 7, below in this Opening Brief.

4.2.1.9 Project Management and Reporting Toolset Enhancements

PG&E is requesting $0.500 million for Project Management and Reporting Toolset Enhancements.[527] The project will provide more sophisticated project portfolio management tools to better manage and organize projects across the company. DRA's corresponding test year estimate is $0.430 million.[528] Due to its concerns about PG&E's Concept Estimating Tool, DRA

[524] Ex. 18 (PG&E-4 workpapers), p. WP 2-68.

[525] Ex. 18 (PG&E-4 workpapers), p. WP 2-13.

[526] Ex. 18 (PG&E-4 workpapers), p. WP 2-70.

[527] Ex. 18 (PG&E-4 workpapers), p. WP 2-15.

[528] Ex. 73 (DRA-5), p. 11.

reduced forecasted expenses for the project by 14% as recommended in Section 7, below in this Opening Brief.

4.2.1.10 Customer Connections Online (CCO) Tools

PG&E is requesting $3.897 million for CCO Tools. PG&E says the project will revamp existing, older customer-facing systems to provide new Customer Connections Online (CCO) tools that better allow customers to create and track service requests.[529] DRA's corresponding TY estimate is $1.949 million.

CCO Tools is PG&E's most expensive expense request in Electric Operations Technology. The individual project costs for CCO Tools are higher than every annual recorded expense from 2007-2011 for the entire MWC JV.

PG&E failed to provide sufficient cost-benefit analyses to support the high project costs. When DRA asked PG&E to provide any cost-benefit analyses used in determining the TY2014 forecast, PG&E directed DRA back to Exhibit (PG&E-4) WP 2-84,[530] which provides a vague description of future cost-savings and benefits, none of which PG&E quantified. The customer savings and benefits do not justify the extremely high cost of the project to ratepayers.

PG&E forecasted $0.500 million for 2012 project expenses, but only spent $0.221 million, which is less than half of its 2012 forecast.[531] DRA's TY2014 estimate is $1.949 million, which is half of PG&E's TY2014 forecast of $3.897 and should be sufficient to cover the costs of this project.

4.2.1.11 Workforce Mobilization by Field Crew or Work Type

PG&E is requesting $1.858 million for its Workforce Mobilization by Field Crew or Work Type Project.[532] The money is being requested for expenses on the following projects: $0.614 million for Mobile for Division (Locally Headquartered) Crews, $0.150 million for Application Upgrade for Pole Test & Treat Crews, $115,200 for Mobile for General Construction (T-300) Crews, $0.430 million for Distribution Substation Crews, $0.110 million for Additional Crew Members, and $0.440 million for Automation of Clearance and Switching

[529] Ex. 18 (PG&E-4 workpapers), p. WP 2-81.

[530] Ex. 73 (DRA-5), p. 12 citing DRA-067-EJ1 question 15e.

[531] Ex. 73 (DRA-5), p. 12.

[532] Ex. 18 (PG&E-4), p. WP 2-15.

Processes. As discussed below in the section on Capital expenditures, DRA recommends that the Commission reject PG&E's request for funding of Workforce Mobilization projects. Therefore, DRA recommends that the Commission also reject the associated project expenses

4.2.1.12 Work Scheduling and Dispatch System Consolidation

PG&E is requesting $1.113 million for its Workforce Mobilization by Field Crew or Work Type Project.[533] PG&E says the project will develop a more integrated scheduling system to better manage work crews, their schedules, and their required work; the tool is intended to replace PG&E's current manual tracking processes.[534] As discussed below in the section on Capital expenditures, DRA recommends that the Commission reject PG&E's request for funding of the Work Scheduling and Dispatch System Consolidation project. Therefore, DRA recommends that the Commission also reject the associated project expenses.

4.2.2 Capital Expenditures

The correlating Major Work Category for capital projects for MWC JV is MWC 2F. MWC 2F is comprised of twenty-eight programs identified above. As can be seen in the tables above, PG&E's costs have been increasing at an incredible rate. PG&E started with $13.6 million in capital expenditures in 2010, and now requests $72.2 million in TY 2014, an increase of 430% in only five years.[535] DRA discusses each program MWC 2F in the following sections.

4.2.2.1 Workforce Mobilization projects

PG&E is proposing nine separate Workforce Mobilization projects for the years 2010 through 2016, which total more than $77.5 million in capital expenditures, and $3.6 million in expenses.[536] PG&E says these projects are for its ongoing approach to deploy mobile technologies to the Electric Distribution workforce and specifically focus on the 2013-2016 workforce mobilization deployment activities by crew type PG&E claims that mobile initiatives

[533] Ex. 18 (PG&E-4), p. WP 2-15.

[534] Ex. 18 (PG&E-4), p. WP 2-94.

[535] Ex. 76 (DRA-8), p. 55.

[536] Ex. 18 (PG&E-4), pp. WP 2-88 & WP 2-89.

put the technologies in the hands of the workforce to deliver safe and reliable services to PG&E's customers in a streamlined and coordinated manner.[537]

PG&E has capitalized $20 million on its workforce mobilization project to date and will not see any savings until 2013 where it claims it will receive $2.8 million in savings, $5.2 million in savings in 2014, and $7.2 million in savings in 2015 and beyond.[538] The capital cost revenue requirement from the $77.5 million in capital expenditures from 2010 through 2016 generates annual costs of $11.6 million a year, which exceeds PG&E's claimed annual savings by $4.4 million a year.

DRA recommends that the Commission reject PG&E's workforce mobilization program as an inefficient use of ratepayers' funds. PG&E needs to analyze its projects to determine that only cost effective projects are requested and if necessary wait until it can make a project cost effective. In future GRCs, PG&E should demonstrate that ratepayer benefits exceed the additional cost of these projects.[539]

4.2.2.2 The Electric Distribution-Geographic Information System (ED-GIS (Electric))

PG&E forecasts expenses of $22.2 million in 2012, $32.2 million in 2013, and $27.8 in 2014. PG&E claims that its ED-GIS project will enhance and convert PG&E's electric distribution asset data into a centralized GIS that is integrated with a remodeled SAP asset database.[540] PG&E claims that the main objective for pursuing the ED-GIS project is to improve safety, compliance, and data integrity by ensuring the accuracy and accessibility of critical asset records.

Again, cost was not a factor that PG&E uses to justify this project. In fact, this project is cost-ineffective and negatively impacts ratepayers.

In Rulemaking 11-02-019, a similar program to the ED-GIS project was reviewed. PG&E requested funding for its Pipeline Records Integration Program. PG&E stated that the

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[537] Ex. 18 (PG&E-4), p. WP 2-86, Project Description section.

[538] Ex. 18 (PG&E-4), p. WP 2-86, Project Description section.

[539] Ex. 76 (DRA-8), p. 56.

[540] Ex. 18 (PG&E-4), p. WP 2-51, Project Description section.

new system would consolidate existing record management systems into a central, integrated system that will enable PG&E to:

> Capture, track, update, and manage specifications and maintenance data as well as all location and connectivity in two core systems;
>
> Improve traceability and verification of asset data by providing links to source document;
>
> Improve integrity and risk analysis, as well as better schedule inspection and maintenance;
>
> Provide the field work force with mobile tools that allow remote access to existing asset information, and to update electronically new maintenance and inspection information; and,
>
> Offer a data management platform capable of addressing any new recordkeeping obligations in the future.[541]

The Commission disallowed recovery of the Pipeline Records Integration Program stating that:

> "As set forth below, we find that PG&E has not justified including the cost of its gas system records search and organization projects in revenue requirement. PG&E became responsible for its natural gas transmission system the day it installed facilities and equipment for the system. That responsibility includes creating and maintaining records of the location and engineering details of system components. Over the years, PG&E has sought and obtained ratepayer funding for its record-keeping functions. PG&E has imprudently managed its gas system records such that extensive remedial work is now needed to correct past deficiencies. Having created the need for this remedial work by it imprudent historic document management practices, PG&E has not shown by a preponderance of the evidence that the cost of the current document search and organization project can be included in revenue requirement and that the resulting rates will be just and reasonable.[542]
>
> DRA opposes PG&E's request for supplemental ratepayer funding for additional record keeping. As with its gas system, PG&E has been responsible for its Electric Distribution facilities and equipment since the day they were installed. This responsibility includes creating and maintaining records of the location and engineering details of system components. DRA recommends against any funding for PG&E's ED-GIS project, including any funding for capital assets spent in 2012.[543]

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[541] D.12-12-030, pp. 19 & 20.

[542] D.12-12-030, p. 87

[543] Ex. 76 (DRA-8), p. 57.

4.2.2.3 Data Historian for Electric Distribution

PG&E says it plans to spend $24.2 million on its Data Historian for Electric Distribution program between 2014 through 2016.[544]

PG&E says it uses data historian software applications to provide central data archiving and analysis for time series data from PG&E's Supervisory Control and Data Acquisition (SCADA) system. PG&E's proposed Data Historian project will replace the current PG&E historian with a commercially available and industry standard data historian application. According to PG&E, this application would provide PG&E with event analysis, engineering, and planning functions with allegedly more granular data resulting in more powerful analytical tools to meet current and future needs.[545]

PG&E failed to demonstrate that the benefits to ratepayers exceed the cost of this new data historian for electric distribution program. Without a demonstration of ratepayer benefits that exceed the costs of this program, the only impact to ratepayers from this project is additional costs. DRA recommends the Commission reject PG&E's Data Historian for Electric Distribution program until PG&E demonstrates that ratepayer benefits exceed the additional cost of this program.[546]

4.2.2.4 Work Scheduling and Dispatch System Consolidation Project

PG&E say it plans to spend $9.3 million on its Work Scheduling and Dispatch System Consolidation project in 2013.[547] DRA recommends no ratepayer funding for this project.

PG&E currently uses a combination of scheduling tools including FAS, other scheduling systems, Excel spreadsheets and various manual tracking methods to track work, access availability of work crews, schedule required work and dispatch it to the crews based on availability and fit of the crew to the required work. PG&E says wants to move away from manually intensive and non-integrated tools and develop a scheduling system that can look

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[544] Ex. 76 (DRA-8), p. 58.

[545] Ex. 18 (PG&E-4), p. WP 2-27, Project Description section

[546] Ex. 76 (DRA-8), p. 58.

[547] Ex. 76 (DRA-8), p. 59.

across all field crews, make real-time availability and resourcing decisions, and supply field crews with the electronic records needed to perform the work.[548]

PG&E failed to demonstrate that the benefits to ratepayers exceed the cost of this new data Work Scheduling and Dispatch System Consolidation project. Without a demonstration of ratepayer benefits that exceed the costs of this program, the only impact to ratepayers from this project is additional costs.

DRA recommends the Commission reject PG&E's Work Scheduling and Dispatch System Consolidation program until PG&E demonstrates that ratepayer benefits exceed the additional cost of this program.[549]

4.2.2.5 Outage Reporting & Analysis System Replacement

PG&E requests $3.493 million in 2013 and 4.878 million in 2014 for Outage Reporting and Analysis System Replacement project.[550] DRA does not oppose the project, but has concerns about the Concept Estimating Tool PG&E used to make its forecast. Due to those concerns, DRA recommends PG&E's forecasts be reduced by 14%.[551]

PG&E is dependent on legacy tools and manual processes to record outage data and monitor and report reliability metrics. PG&E intends to replace the existing tools and processes with a more automated solution that performs better and allows better outage analysis. These projects will incorporate newly available SmartMeter and SCADA data and improve integration with other PG&E systems. The new solution will allegedly reduce the complexities that PG&E represents it faces outage reports generating reports. PG&E wants the Commission to approve ratepayer funding to move from legacy systems/databases, and leverage reporting functionality from the new Distribution Management System.[552]

PG&E says that without actual customer-level outage data, engineers will use network connectivity models and customer assignments to derive reliability outage data. On the assurance that PG&E's proposed project will allow PG&E to make more accurate reliability

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[548] Ex. 18 (PG&E-4), p. WP 2-94, Project Description section

[549] Ex. 76 (DRA-8), p. 59.

[550] Ex. 18 (PG&E 4 workpapers), p. WP, 2-33.

[551] Ex. 76 (DRA-8,), p. 60.

[552] Ex. 18 (PG&E-4), p. WP 2-31, Project Description section.

metric reports to the Commission, DRA does not oppose it, but adjusted PG&E's estimate by 14% due to its concerns with the accuracy of PG&E's Concept Estimating Tool. DRA recommends that the Commission allow outage reporting and analysis system replacement costs of $2.8 million in 2013 and $3.9 million in 2014.[553]

4.2.2.6 Customer Connections Online

PG&E requests $3.897 million in 2014 for its Customer Connections Online Project.[554] PG&E says this project will improve the tools used by customers to create and track service requests. PG&E noted that deficiencies with the New Business Process (i.e. installing new gas and electric services, modifying existing service points, communications, and predictability of work timing) were key sources of dissatisfaction for customers.[555]

Consistent with DRA's recommendation in the Expense section above, DRA recommends the Commission allow ratepayer funding of 50% of the capital costs for Customer Connection Online tools.[556]

4.2.2.7 Estimator Tools Enhanced with Graphic Work Design

PG&E proposes capital expenditures of $3.0 million in 2013, and $3.0 million in 2014 to replace its current construction design and estimating toolset with more modern, integrated and graphics-based construction visualization and estimation software. PG&E states that these modern tools can significantly improve design and construction consistency and efficiency across construction projects, in addition to integrating with the new Electric Distribution Geographic Information System/Asset Management (ED GIS/AM) solution.[557]

PG&E feels that the work design tools currently in use need to be improved and that this initiative is expected to yield significant benefits beginning in 2016 following widespread tool deployment and stabilization.[558]

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[553] Ex. 76 (DRA-8), p. 60.

[554] Ex. 18 (PG&E-4 workpapers), p. WP 2-83.

[555] Ex. 18 (PG&E-4), p. WP 2-81, Project Description section.

[556] Ex. 76 (DRA-8), p. 60.

[557] Ex. 18 (PG&E-4), p. WP 2-62, Project Description section.

[558] Ex. 18 (PG&E-4), p. WP 2-62, Justification section and p. WP 2-65, Cost and Non-Cost Benefits section.

While DRA is recommending against PG&E's Electric Distribution Geographic Information System/Asset Management because PG&E should already maintain documentation with information about the location of all of its assets, DRA agrees that modern design tools will improve PG&E's ability to design estimate projects and will save PG&E's ratepayers money in the long run. Due to its concerns about the accuracy of PG&E's Concept Estimating tool, DRA recommends the Commission decrease PG&E's estimate by 14%. This results in a forecast for Estimator Tools Enhanced with Graphic Work Design costs of $2.6 million in 2013 and $2.6 million in 2014.[559]

4.2.2.8 Emergency Outage Response Technology

PG&E requests $2.404 million in 2014 for Emergency Outage Response Technology.[560] DRA does not oppose the project, but due to its concerns with the Concept Estimating Tool PG&E used for its forecast, recommends that forecast be reduced 14%.

After DRA's 14% adjustment for costs generated using PG&E's concept estimator tool, DRA recommends capital expenditures of $2.1 million in 2014 and that PG&E be allowed to implement its new Emergency Outage Response Technology project.[561]

4.2.2.9 Vegetation Control Application Replacement

PG&E requests $2.231 million in 2013 for a Vegetation Control Application replacement. DRA does not oppose the project, but due to its concerns with the Concept Estimating Tool PG&E used for its forecast, recommends that forecast be reduced 14%. With that adjustment, DRA recommends that PG&E be authorized 2013 costs of $1.9 million for its Vegetation Control replacement program.[562]

4.2.2.10 1.2.2.10 Asset Risk Management Tool for Public Safety

PG&E requests $1.466 million in 2014 for Asset Risk Management Tool.[563] DRA does not oppose the project, but due to its concerns with the Concept Estimating Tool PG&E used for

[559] Ex. 76 (DRA-8), p. 61.

[560] Ex. 18 (PG&E4 workpapers), p. 2-25.

[561] Ex. 76 (DRA-8), p. 62.

[562] Ex. 76 (DRA-8), p. 63.

[563] Ex. 18 (PG&E-4 workpapers), p. WP 2-57.

its forecast, recommends that forecast be reduced 14%. With that adjustment, DRA recommends that PG&E be authorized 2014 costs of $1.3 million for its asset risk management tool for public safety.

4.2.2.11 SAP Work Management

PG&E requests $751,000 in 2014 for SAP Work Management.[564] DRA does not oppose the project, but due to its concerns with the Concept Estimating Tool PG&E used for its forecast, recommends that forecast be reduced 14%. With that adjustment, DRA recommends that PG&E be authorized 2013 costs of $688,000 and 2014 costs of $430,000 for its SAP work management programs.[565]

4.2.2.12 Build IT projects under $1 million

In 2013, PG&E is seeking $269,000 in Build IT projects under $1 million. PG&E is including two projects in this category. SAP work for $160,000,[566] and customer connection work for $109,000.[567] Both of these projects were discussed previously in this section. Customer connection work was removed in Exhibit 73 (DRA-5) and is removed in this exhibit to be consistent. SAP work was allowed after a 14% decrease consistent with DRA's testimony in Exh. DRA-18.

4.2.2.13 Distribution Management System

PG&E requested $2.4 million in 2012, $6.3 million in 2013 and $904,000 in 2014. DRA recommend $1.8 million in 2012, 44.6 million in 2013 and $647,800 in 2014.

The 13 existing control centers currently use approximately 1,500 linear feet of paper wall maps. To provide the operational flexibility and disaster recovery capabilities intended as part of DCC consolidation while continuing to operate off paper maps is not practical. Electronic wall mapping is a necessary component of the DCC project. Electronic wall mapping

[564] Ex. 18 (PG&E-4 workpapers), p. WP 2-57.

[565] Ex. 76 (DRA-8), p. 63.

[566] Exhibit 18, PG&E-4, p. WP 2-13, line 34

[567] Exhibit 18, PG&E-4, p. WP 2-15, line 48

gives the operators shared access to network information, enables wider geographical jurisdiction, improves process efficiency, and reduce manual processes.[568]

PG&E's electronic wall mapping application estimate was created using a combination of inputs: 1) PG&E's Concept Estimator tool; 2) a previous project estimate for the development of an electronic wall mapping system at PG&E; and 3) quotes for project components from the vendor.[569]

DRA has reviewed PG&E's cost estimates and made two adjustments. DRA removed 1) a 20% high project complexity contingency fee added by PG&E;[570] and, 2) DRA decreased the remaining costs by 14% to remove the excessive costs that are included in the costs calculated using PG&E's Concept Estimator tool that are identified in Section 7 of this Opening Brief.

PG&E included a 20% contingency fee when estimating the cost of its distribution management system. Contingency fees are useful for correcting inexperienced business, business that have a small number of projects a year, and business that cannot afford experienced professionals. PG&E is none of these. PG&E is one of the largest businesses in the United States, constructs several billion dollars in projects each year, and has a professional staff. PG&E recently constructed a similar project for its transmission management system. In addition, any variance from this project would get lost in the variance from the thousands of other projects. PG&E does not need to include a 20% contingency fee for any of its projects. Any variance is immaterial to PG&E's bottom line.

4.3 Applied Technology Services

4.3.1 Expense

PG&E forecasts $2.151 million in TY2014 expenses for ATS, which is an increase of $1.199 million or 116.61% over 2012 expenses of $0.952 million.[571] The corresponding DRA estimate for PG&E's ATS expenses is $1.066 million, which is $1.085 million less than PG&E's

[568] Ex. 18 (PG&E-4), p. WP 11-26.

[569] Ex. 18 (PG&E-4), p. WP 11-29.

[570] Ex. 18 (PG&E-4), p. WP 11-22, line 53.

[571] Ex. 18 (PG&E-4 workpapers), p. WP 3-1. 2012 data from DRA-108-CKT question 4.

TY2014 forecast. DRA's TY estimate is $0.114 million more than PG&E's 2012 recorded expenses of $0.952 million.

4.3.1.1 MWC AB

PG&E records expenses for the ATS program in Major Work Category (MWC) AB. Most expenses are charged to the organization or department within PG&E that requests the service from ATS. Expenses for the following programs are charged to ATS: Electric and Magnetic Field (EMF) program, Climate Change Program, ATS Document Library Scanning and Archiving, and the expense portion of the San Ramon Technology Center Facility Upgrades.[572] After reviewing PG&E's testimony, workpapers, and discovery responses, DRA agrees with PG&E's TY expense forecast for the EMF program and the Climate Change program. DRA disputes PG&E's forecast for ATS Document Scanning and Archiving and the San Ramon Upgrades.

4.3.1.2 ATS Document Library Scanning and Archiving

PG&E forecasts $1.000 million in TY2014 expenses for the ATS Document Library Scanning and Archiving project.[573] PG&E says the project will convert the entire ATS library of reports and records into electronic format.[574] PG&E developed its test year forecast by multiplying the estimated number of documents by the estimated unit cost associated with retrieving, scanning, and special handling of the documents. The forecast includes the cost of a project manager to oversee the project.[575]

While seemingly very simple, PG&E has failed to justify the costs for this sub-MWC JV project. PG&E's forecast for scanning expenses is $818,000, which constitutes the largest portion of the forecasted $1 million in project expenses. PG&E says it calculated its forecast for scanning costs by multiplying the estimated number of documents by the estimated image cost for scanning. Scanning costs varied based on the size of the document, with oversized images estimated to cost more. DRA asked PG&E to explain in detail how it developed its scanning costs and provide all supporting documentation and calculations.

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[572] Ex. 17 (PG&E-4) page 3-3.

[573] Ex. 18 (PG&E-4 workpapers), p. WP 3-9.

[574] Ex. 17 (PG&E-4), pp. 3-6.

[575] Ex. 18 (PG&E-4 workpapers), p. WP 3-9.

PG&E's responses reveal that the majority of the company's cost estimates are based on informal proposals and PG&E's subjective judgment. Significantly, PG&E failed to respond to DRA's request to provide documentation or evidence of any solid calculations, paper estimates, or analyses.

DRA considered ratepayer benefits when assessing the ATS Library Project. PG&E stated, "Although this project does not directly result in an ongoing reduction in the cost of maintaining ATS records, there are future benefits from an efficiency standpoint."[576] The efficiencies to which PG&E refers focus mostly on quicker and easier retrieval of ATS documents by PG&E employees,[577] and add little value to ratepayer savings, reliability, or safety. This project is largely discretionary.

DRA opposes funding for the ATS Library project on the basis that it more than doubles expenses in MWC AB from all prior years while providing no hard evidence to substantiate the high project costs.[578]

4.3.1.3 Expense Portion of San Ramon Technology Center Facility Upgrades

PG&E forecasts $85,000 for the expense portion of the project.[579] DRA recommends no additional funding for this project.[580]

The San Ramon Technology Facility (SRTC) upgrade is a new project that PG&E says focuses on modernizing the common areas of the facility.[581] PG&E does not need additional funding for the SRTC upgrades. Building upgrades and modernizations are ongoing processes. In PG&E's project summary for the SRTC Upgrade, PG&E noted: "PG&E has invested in new labs and testing facilities at this location and the common areas need to be upgraded to support the work performed in these labs."[582] It makes financial sense for ratepayers that PG&E is able

[576] Ex. 17 (PG&E-4), p. 3-13.

[577] Ex. 17(PG&E-4), pp. 3-13.

[578] Ex. 73 (DRA-5), pp. 16-21.

[579] Ex. 18 (PG&E-4 workpapers), p. WP 3-26.

[580] Ex. 73 (DRA-5), p. 22.

[581] Ex.17 (PG&E-4), pp. 3-8.

[582] Ex. 18 (PG&E-4 workpapers), p. WP 3-25.

to reallocate funding from previous investments and upgrades, such as the new labs and testing facilities mentioned by PG&E, to other locations such as the SRTC facility upgrades. Because there are embedded costs for facility upgrades, DRA recommends no additional funding for the project.

4.3.2 Capital Expenditures

The corresponding MWC for capital expenditures for Applied Technology is MWC 05. MWC 05 is comprised of three subprograms: (1) Tools & Equipment, Chapter 3; (2) Tools & Equipment, Chapter 20; and, (3) Material Overdraw.[583] DRA will discuss the remaining cost element of MWC 05 in the following sections.

4.3.2.1 Tools & Equipment

MWC 05 includes the cost of miscellaneous tools and equipment to support distribution and generation work. For PG&E's Applied Technology Service center, capital expenditures in MWC 05 are needed to ensure that employees performing field and laboratory tests have appropriate tools and test equipment. Regular expenditures are necessary to replace damaged, worn out, or obsolete tools and to ensure specialized tools are available to perform testing and other analytical functions.[584]

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 agrees with this three-year total amount. 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 3-year total from 2012-2014 equals PG&E's forecasted 3-year total. Therefore, DRA recommends capital expenditures of $721,300 for 2012, $554,300 for 2013, and $554,300 for 2014.

Tools and Equipment

MWC 05 includes the cost of miscellaneous tools used by operations, maintenance and construction employees to perform distribution-related work. These expenditures are needed to: (1) Ensure tools are available for basis operations, maintenance, and construction activities;

[583] Ex. 17 (PG&E-4), p. 13-16, lines 23-24.

[584] Ex. 17 (PG&E-4), p. 3-9, lines 1-11.

(2) Replace damaged, work out, or obsolete tools need to perform work; and, (3) Ensure specialized tools are available to install, test, remove or diagnose equipment.[585]

Because PG&E's request is consistent with recent tools and equipment activity, DRA does not take exception to PG&E's miscellaneous tools request for 2013 and 2014 capital expenditures in this general rate case. Therefore, DRA recommends capital expenditures of $3.4 million for 2012, $2.0 million for 2013, and $2.0 million for 2014.[586]

Material Overdrawn

PG&E uses MWC 05 to record credits associated with overdrawn materials. Material for capital projects are typically charged against the capital order for a specific project. Sometimes material is purchased for a project and goes unused. Normally, the overdrawn material is credited back to the capital order that was initially used to purchase the material. However, it sometimes occurs that the capital order is closed for further charging before the overdrawn material is credited back to the capital order. In these cases, the material is credited back to an order in MWC 05.[587]

Because PG&E's material overdrawn capital expenditure proposed is consistent with historical expenditures, DRA does not take exception with PG&E requested amount in this general rate case. Therefore, DRA recommends capital expenditures of ($6.5) million for 2012, ($5.1) million for 2013, and ($5.1) million for 2014.[588]

4.4 Electric Mapping and Records Management

PG&E's Electric Mapping and Records Management Program creates new maps, records updates, and maintains the electric system distribution maps. It also provides mapping information for planning new services, analyzing existing services, forecasting work and maintenance of PG&E's facilities.

PG&E forecasts $31.117 million for Electric Mapping and Records Management expenses for the 2014 Test Year. This is an increase of $27.753 million, or 825%, over 2011

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[585] Ex. 17 (PG&E-4), p. 20-5, lines 7-18.

[586] Ex. 75 (DRA-8), p. 35.

[587] Ex. 17 (PG&E-4), pp. 20-5 & 20-6, lines 21-3.

[588] Ex. 75 (DRA-8), p. 36.

recorded adjusted expenses of $3.364 million.[589] DRA recommends that the Commission adopt a forecast of $4.416 million for Electric Mapping and Records Management expenses for the Test Year.[590]

PG&E records expenses for its Electric Mapping and Records Management in MWC GE. PG&E's forecast includes additional funding, over 2011 recorded levels, of $10.0 million for Field Asset Inventory, $14.200 million for Converting Paper-Based Records to Electric Format, $1.0 million for Updating Electric Records to Standard Format, and $0.411 million for Records Quality Assurance Program.[591] PG&E's forecast includes contingency costs for Field Asset Inventory Project of $3.240 million, for Electric Distribution As-Built Records Scanning Project of $3.670 million, for Distribution Substation Records Scanning Project of $324,000, and for Distribution Maintenance Records Scanning Project of $0.409 million.

DRA forecasts $4.416 million using a five year average (2007-2011). DRA's forecast is $1.052 million more than PG&E's 2011 recorded adjusted expense level.[592] DRA recommends no ratepayer funding for any "contingency" costs. While it is not uncommon for contingency costs to be added to proposed capital projects, DRA can recall no instance of the Commission approving contingency costs for O &M projects.[593]

In Rebuttal, PG&E says that "…reliance exclusively on historical spending patterns, as suggested by DRA, should be rejected by the Commission."[594] In fact, DRA is not suggesting that the Commission rely exclusively on historical spending. Actually, DRA is concerned that PG&E has been asking for, and receiving, approximately twice as much for Mapping and Records Management as it has actually been spending for that purpose. In the TY 2011 GRC, PG&E said that its forecasted increase was "… primarily driven by project work that is needed to address issues related to the accuracy and standardization of data on the maps and in PG&E's

[589] Ex. 17 (PG&E-4), p. 4-13, Table 4-3.

[590] Ex. 74 (DRA-6), p. 7.

[591] Ex. 17 (PG&E-4) p. 4-8 to 4-12.

[592] Ex. 74 (DRA-6) p. 9.

[593] Ex. 74 (DRA-6), p. 11, footnote 23.

[594] Ex. 55 (PG&E-19), p. 4-5.

databases."[595] If that was work that needed to be done in the TY 2011 GRC, then PG&E should have done it, and the funding that is still embedded in rates is available to be used for other Mapping and Records Management work.

Here in the TY 2014 GRC, one of the most expensive projects PG&E proposes is a Field Asset Inventory. PG&E says the Field Asset Inventory project is to perform a detailed inventory of Electric Distribution System overhead and underground facilities to identify discrepancies between actual conditions and assets in the field. According to PG&E:

> … some records contained in its Centralized Electric Distribution System Analysis (CEDSA) database related to the manufacturer and date installed for certain pieces of equipment such as line switches or distribution transformers are missing or were given default values in the database. PG&E believes this information is missing because PG&E decided not to collect this information in the 1970s and 1980s when the CEDSA database and its predecessor databases were created. PG&E also believes that some of this information was not collected and reported by its crews at the time the equipment was installed so it could not be easily recorded in the database.[596]

Apparently, because there was no CPUC regulation requiring PG&E to keep records of the manufacturer and date of installation, and no business need for the information in the late 1970s, PG&E "… did not spend the time and effort to go back out and re-create that information…"[597] Now, however, "…as this equipment reaches the end of its expected life, additional information is necessary to support informed asset and risk management practices."

It is not clear to DRA how PG&E can know what equipment is reaching the end of its expected life if PG&E does not know who manufactured it, or when it was installed. As PG&E itself admits, in the absence of information about the manufacturer and date of installation, PG&E may not be able to make "…optimal replacement or maintenance decisions to minimize investments and maintain system safety and reliability."[598] When asked how PG&E could be sure that it has in fact, been making optimal decisions to "minimize investment and maintain

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[595] Ex. 195, p. 26-11.

[596] Ex. 74 (DRA-6), p. 13, citing DRA-PG&E-085-TLG, Q. 7b.

[597] 17 RT 1833, Dasso/PG&E.

[598] Ex. 55, p. 4-11.

system safety and reliability" the response was circular: "I base [that opinion] on the overall performance and reliability of our system."[599]

The most expensive Mapping and Records Management Program PG&E proposes in this GRC is to Convert Paper-Based Records to Electric Format for TY 2014 expenses of $14.2 million. With respect to this project, PG&E says that "…converting its paper records to electronic format and storing these records in an industry standard database will assure the records do not deteriorate over time, as paper records can do. This process will also make these records readily available electronically to PG&E employees or others who use them, minimizing travel to where the records are stored or mailing documents to the required locations."[600]

It can hardly be a new discovery to PG&E that "paper records can deteriorate." It should, similarly, be obvious that, to be of any use, PG&E's records must be "…maintained in a way that ensures timely, efficient, and accurate retrieval of needed information." PG&E has had a Mapping and Records Management Program for its electric distribution system for at least thirty years, funded by PG&E's ratepayers.[601] PG&E has received funding in past GRCs (2003, 2007, 2011) to ensure that its Electric and Gas mapping records were maintained in an accurate, complete and easily accessible manner. Yet, in every year from 2007 through 2011, PG&E spent less on Electric Distribution Mapping and Records Management than it had imputed, sometimes dramatically less. For example, PG&E's 2011 recorded adjusted expenses for Major Work Category GE were $3.364 million, or 111% lower than PG&E's imputed amount.[602]

PG&E's request for MWC GE- Mapping and Records Management is very similar to PG&E's proposal in its Pipeline Safety Enhancement Plan regarding its Pipeline Records Integration Program.[603] In the PSEP proceeding, PG&E requested incremental ratepayer funding for collecting, reviewing organizing and verifying critical records associated with its installed gas pipeline segments and for additional funding to upgrade and consolidate its multiple existing

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[599] 17 RT 1839, Dasso/PG&E.

[600] Ex. 55 (PG&E-19), p. 4-10.

[601] 17 RT 1815, 1820, Dasso/PG&E.

[602] Ex. 74 (DRA-6), p. 10.

[603] *See* D.12-12-030, mimeo, p. 18, Section 2.2; 2012 Cal.PUC LEXIS 600.

Information Technology systems (SAP and its Geographic Information System (GIS)). The Commission rejected PG&E's request for ratepayer funding for this program saying:

> As set forth below, we find that PG&E has not justified including the costs of its gas system records search and organization projects in revenue requirement. PG&E became responsible for its natural gas transmission system the day it installed facilities and equipment for the system. That responsibility includes creating and maintaining records of the location and engineering details of system components. Over the years, PG&E has sought and obtained ratepayer funding for its record-keeping functions. PG&E has imprudently managed its gas system records such that extensive remedial work is now needed to correct past deficiencies. Having created the need for this remedial work by its imprudent historic document management practices, PG&E has not shown by a preponderance of the evidence that the costs of the current document search and organization projects can be included in revenue requirement and that the resulting rates will be just and reasonable.[604]
>
> What the Commission stated regarding PG&E's natural gas transmission system, is also true here: PG&E became responsible for its electric distribution system the day it installed facilities and equipment for the system. PG&E's "… responsibility includes creating and maintaining records of the location and engineering details of system components." Apparently, PG&E has not effectively used the funding it has received to ensure that its Electric Distribution Mapping and Records Management systems are properly corrected, updated and maintained; if the records had been properly maintained, PG&E would not be requesting an increase of 825% in the Test Year. It is unreasonable to force PG&E ratepayers to pay again to address PG&E's deficient records management.**605**

PG&E also fails to demonstrate or incorporate into its forecast any calculated savings and benefits and associated efficiency gains in dollars for its proposed mapping and records projects. As the Commission has held in other GRC decisions where descriptions of potential benefits of projects provide general information, but not enough to show whether the costs are justified in either the short or long term.

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[604] D.12-12-030, p. 87 (emphasis added); 2012 Cal PUC LEXIS 600.

[605] Ex. 74 (DRA-6), p. 17, footnote 34: PG&E proposes to use 2011 GRC authorized funding to conduct the first year of work for its Field Asset Inventory project in 2013 and has already conducted targeted specific asset inventories using 2011 GRC authorized funding (DRA-PG&E-085-TLG Q.11-b).

With this type of analysis and showing it is possible to explicitly include associated costs in rates but it is not possible to explicitly reflect any of the associated benefits or savings, whatever they may ultimately be, in rates for this rate case cycle. This imbalance is troubling. In general, it is our obligation to consider both the costs and, if applicable, the benefits/savings of utility proposals. If the benefits/savings are ultimately small when compared to costs, the proposal should probably not be implemented or included in rates. If the benefits/savings are substantial, it would be reasonable to include both the costs and benefits/savings in determining rates. For the advanced technology programs/projects, the lack of information regarding benefits/savings precludes us from making such determinations. In this decision, we are authorizing significant increases in T&D O&M and capital expenditures. How the potential benefits of the advanced technology programs/projects relate to SCE's proposals for increased spending is not clear. Whether the advanced technology spending results in the modification of any future spending related to T&D costs has not been shown.[606]

PG&E's forecast method also omits historical embedded costs (i.e., those that are already in rates) associated with the upgrades, revisions, enhancements, database consolidations, and on-going operation and maintenance of its existing database systems. For example, PG&E says its proposed Electric Distribution Geographic Information System/Asset Management (ED GIS/AM) project "…is a continuation of and enhanced approach to the Automated Mapping and Facilities Management (AM/FM) Project described in PG&E's TY 2011 GRC."[607] In its decision in the TY 2009 SCE GRC, the Commission was confronted with a similar situation:

> SCE's forecast also includes a $4.812 million (constant 2006$) increase for insulator replacement as part of its Transmission Life Extension Program. SCE claims that the increase represents the cost of materials and the use of contract crews to supplement SCE's crews for insulator and hardware replacements. DRA claims historical expenses have embedded costs for insulator replacements. According to SCE, some of the circuits it will be replacing are over 90 years old and many of the insulators on its

[606] D.06-05-016, mimeo., p. 64; 2006 Cal. PUC LEXIS 189.

[607] Ex. 17 (PG&E-4), pp. 2-25 and 2-26. PG&E suspended the AM/FM project after the San Bruno explosion in September 2010 to "assess the effectiveness of the project" in order to achieve accurate, verifiable, and traceable asset information. The AM/FM project closed in September 2011 and was re-launched as separate GIS/AM projects for Electric Distribution, Gas Distribution, Electric Transmission and Gas Transmission.

> system have exceeded their life expectancies. *While these types of programs may be a cost-effective way to maintain the integrity of the system and slow the deterioration of capital assets, SCE has not sufficiently addressed the relationship of these programs to costs embedded in historical data.* Accordingly, SCE's request for $4.812 million to increase its insulator replacement as part of its Life Extension Program is denied.[608]

DRA recommends that the Commission continue all of these policies discussed above and deny PG&E's request for incremental ratepayer funding to address Electric Distribution Mapping and Records Management deficiencies.

4.5 Electric Distribution Maintenance

4.5.1 Expense

PG&E forecasts $125.903 million for TY2014 Electric Distribution Maintenance expenses, which is an increase of $11.310 million or 9.9% over 2011 expenses of $114.593 million.[609] The corresponding DRA estimate is $103.557 million, which is $22.346 million less than PG&E's forecast of $125.903 million.[610]

The Electric Distribution Maintenance (EDM) Program is comprised of the maintenance activities that uphold PG&E's electric distribution line assets. EDM work includes patrols, inspections, preventive maintenance, and equipment repair for PG&E's overhead, underground, and network facilities.[611]

EDM expenses are recorded in five Major Work Categories: BF for Patrols and Inspection with a forecast of $46.286 million, KA for Electric Distribution Maintenance – Overhead with a forecast of $2.713 million, KB for Electric Distribution Maintenance – Underground with a forecast of $53.659 million, KC for Electric Distribution Maintenance – Network with a forecast of $17.253 million, and BK – Maintenance of Other Equipment with a forecast of $5.992 million.

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[608] D.09-03-025, mimeo, p. 72, emphasis added; 2009 Cal. PUC LEXIS 165.

[609] Ex. 18 (PG&E-4 workpapers), p. WP 5-1.

[610] Ex. 73 (DRA-5), p. 22.

[611] Ex. 17 (PG&E-4), p. 5-12.

Most forecasted expenses in the EDM Major Work Categories were developed by estimating the number of work units to be performed and multiplying them by the estimated unit cost.[612] This method was also used to develop the additional project costs.

4.5.1.1 MWC BF—Patrols and Inspections

PG&E forecasts $46.286 million in expenses for MWC BF, which is an increase of $1.412 million or $3.5% over 2011 expenses of $44.874 million.[613] DRA does not oppose this forecast.

4.5.1.2 MWC KA—Electric Distribution Maintenance Overhead

PG&E forecasts $53.659 million in TY expenses for MWC KA, which is an increase of $12.576 million or 30.61% over 2011 expenses of $41.083 million.[614] The corresponding DRA estimate for overhead maintenances expenses is $35.009 million.[615] DRA agrees with PG&E's TY expense forecast for the following items: overhead notifications, bird safe and bird retrofits, overhead critical operating equipment, radio and television interference investigations, regs/recl CM tag, and transformer labor reclassification. The discussion, which follows, pertains to areas where DRA's forecasts differ from PG&E's request.

Streetlight Group Replacements and Streetlight Burnouts

PG&E forecasts $0.325 million for streetlight group replacements and $6.409 million for streetlight burnouts. DRA accepts PG&E's forecast for streetlight group replacements, but recommends $5.930 million for streetlight burnouts.[616]

The streetlight group replacements program is considered preventive maintenance because streetlights are proactively replaced before a failure occurs while the streetlight burnouts program is corrective maintenance because streetlights are replaced after they have failed.[617] DRA asked PG&E to explain why expenses for streetlight burnouts increased from 2007-2011.

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[612] Ex. 17 (PG&E-4), p. 5-43.

[613] Ex. 18 (PG&E-4 workpapers), p. WP 5-1.

[614] Ex. 19 (PG&E-4 workpapers), p. WP 5-10.

[615] Ex. 73 (DRA-5), p. 23.

[616] Ex. 73 (DRA-5), p. 25, Table 5-11.

[617] Ex. 17 (PG&E-4), p. 5-19.

PG&E's response, supported by historical numbers, shows that there is an inverse relationship between streetlight replacements (preventive maintenance) and streetlight burnouts (corrective maintenance). As the number of streetlight replacements and associated costs decreased from 2007-2011, the number of annual burnouts and associated costs increased from 2007-2011.

PG&E is forecasting 5,000 streetlight replacements starting in 2012 and continuing into the TY; this is 4,261 units or 576.59% greater than the 2011 amount of 739 units. PG&E is forecasting 19,729 burnouts in 2014; this is 183 units or 0.9% less than the 2011 amount of 19,913 units. PG&E stated that the reduction in streetlight replacements led to an increase in streetlight burnouts over the past five years; alternatively, as PG&E increases its number of replacements in the 2012-2014 timeframe, the number of streetlight burnouts and associated costs should decline more significantly than 183 units.

DRA accepts PG&E's forecast for 5,000 streetlight group replacements, and the associated costs of $0.325 million, with the expectation that the number of streetlight burnouts should notably decline. DRA's forecast of streetlight burnouts is 18,255 units, which DRA developed by using a 3-year average (2009-2011) of streetlight burnouts per year.[618] DRA developed its TY estimate of $5.930 million for streetlight burnouts by multiplying 18,255 units by PG&E's forecasted unit cost of $325, which is a higher unit cost than all recorded years since 2007. DRA recommends the Commission adopt a TY estimate of $5.930 million for streetlight burnouts.[619]

Insulator Washing

PG&E forecasts $0.459 million for TY2014 insulator washing expenses.[620] PG&E's requested increase is 2086% over 2011 expenses of $0.021 million. DRA recommends a TY estimate of $0.052 million.[621]

Insulator washing is a routine activity. DRA, therefore asked PG&E to explain why PG&E was forecasting such an increase. PG&E's response was to recite a number of

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[618] See Table 5-12 for recorded 2009, 2010, and 2011 number of units.

[619] Ex. 73 (DRA-5), p. 26.

[620] Ex. 18 (PG&E-4 workpapers), p. WP 5-10.

[621] Ex. 73 (DRA-5), p. 29.

generalities about the importance of insulator washing, and refer DRA back to PG&E's direct testimony.

Nothing in PG&E's data response nor in its Direct Testimony this demonstrates the need for this level of additional funding. DRA, therefore, recommends that the Commission adopt a 3-year average (2009-2011)[622] of recorded adjusted expenses for insulator washing, or $0.052 million.[623]

Idle Facilities

PG&E forecasts $3.819 million in expenses for the Idle Facilities project. As discussed in the Capital expenditures section, DRA recommends that the Commission reject PG&E's request for funding of the Idle Facilities project.[624] Therefore, DRA recommends that the Commission also reject the associated project expenses.

DRA's corresponding TY estimate for routine maintenance of idle facilities is $5,650. DRA developed its TY estimate by taking a 3-year average (2009-2011) of recorded expenses for idle facilities.[625]

Infrared Inspection and Tags

PG&E forecasts $13.500 million in expenses for its Infrared Inspection and Tags project. As discussed below in the Capital expenditures section, DRA recommends that the Commission reject PG&E's request for funding of the Infrared Inspection and Tags project. Therefore, DRA recommends that the Commission also reject the associated project expenses.[626]

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[622] DRA took an average of 2009, 2010, and 2011 expenses, expressed in 2011 dollars. DRA totaled forecasts for all line items within a MWC before escalating to 2014 nominal dollars. PG&E did not escalate individual line items. DRA employs this methodology in every instance within this exhibit where DRA bases its TY forecast on a multi-year average.

[623] 2009 recorded expenses = $110,819; 2010 recorded expenses = $23,080; 2011 recorded expenses = $21,024. The 3-year average is $51,641. Recorded expenses in 2011 dollars from DRA-128-EJ1 question 18.

[624] Ex. 76 (DRA-8).

[625] 2009 recorded expenses = $6,580; 2010 recorded expenses = $8,781, 2011 recorded expenses = $1,589. The 3-year average is $5,650. Recorded expenses in 2011 dollars from DRA-128-EJ1 question 18.

[626] Ex. 76 (DRA-8).

4.5.1.3 MWC KB – Electric Distribution Maintenance Underground

PG&E forecasts $17.253 million in expenses for MWC KB.[627] The corresponding DRA estimate for underground maintenance expenses is $13.557 million.[628]

DRA agrees with PG&E's TY expense forecast for the following items: Underground Notifications, Underground COE, Transformer Labor Reclassification, Major Notifications, and Elbows/Splice Replacement. The discussion, which follows, pertains to areas where DRA's forecasts differ from PG&E's request.

Underground Oil Switch Replacements

PG&E forecasts $1.500 million in expenses for its Underground Oil Switch Replacement project. As discussed below in the Capital expenditures section, DRA recommends that the Commission reject PG&E's request for funding of the Underground Oil Switch Replacement project. Therefore, DRA recommends that the Commission also reject the associated project expenses.

BART Cable Repair

PG&E forecasts $131,250 in expenses for BART Cable Repair. The corresponding DRA estimate is $25,648.

PG&E has no historical costs for 2008; expenses for 2009 and 2010 are respectively $54,703 and $17,790. DRA, therefore asked PG&E to provide a detailed explanation for how the TY2014 forecast of $131,250 was developed.

According to PG&E, "BART cable repair work is reactive, i.e., PG&E only performs this work when a BART cable fails or is damaged."[629] No repairs were needed in 2007, 2008, or 2011, and repairs in 2009 and 2010 were substantially lower than PG&E's TY2014 forecast. PG&E does not provide any documentation or support to explain why additional funding is needed for BART Cable Repairs. DRA developed its TY estimate of $25,648 by using a 3-year average of recorded expenses (2009-2011), expressed in 2011 dollars.[630]

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[627] Ex. 18 (PG&E-4 workpapers), p. WP 5-1.

[628] Ex. 73 (DRA-5), p. 30.

[629] Ex. 73 (DRA-5), p. 31 citing DRA-128-EJ1 question 28a

[630] 2009 recorded expenses = $58,501; 2010 recorded expenses = $18,442, 2011 recorded expenses = $0. The 3-year average is $25,648. Recorded expenses in 2011 dollars from DRA-128-EJ1 question 27.

Underground Barcode Enclosures

PG&E forecasts $2.0 million for its Underground (UG) Barcode Enclosures Program.[631] DRA recommends no ratepayer funding for this project at this time.[632]

PG&E says the Underground Barcode Enclosures Program will establish a bar code scanning system that allows PG&E to identify data associated with underground enclosure equipment.[633] DRA asked PG&E for more information about the program and discovered that the implementation of PG&E's Underground Barcode Enclosures Program and the associated project benefits are dependent on the successful adoption of mobile technology by PG&E.[634]

PG&E set the project start date for 2012. PG&E forecasted that it would install bar codes for 60,000 enclosures in 2012 for a total cost of $600,000.[635] DRA asked PG&E about the amount of work completed in 2012 for this project and learned that none had been installed in 2012.[636]

DRA asked PG&E for any cost-analyses associated with the project.[637] PG&E stated, "There are no cost reductions or avoidances associated with this project. The primary purpose of the project is improved asset inventory knowledge and management."[638] The project has little to no ratepayer value. PG&E provided no additional documentation or analyses to substantiate its request of $2.0 million.

It is premature to ask for $2.0 million of ratepayer funding for a project relying so heavily on technology that is still in development, especially when there are no cost reductions or avoidances associated with the project. It is not the appropriate time to implement this largely discretional and expensive project. DRA recommends that the Commission deny PG&E's request for funding at this time.[639]

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[631] Ex. 18 (PG&E-4 workpapers), p. WP 5-48.

[632] Ex. 73 (DRA-5), p. 34.

[633] Ex. 18 (PG& 4 workpapers), p. WP 5-47.

[634] Ex. 73 (DRA-5), p. 32 citing DRA-128-EJ1 question 32a.

[635] Ex. 18 (PG&E-4 workpapers), p. WP 5-47.

[636] Ex. 73 (DRA-5), p. 33 citing DRA-128-EJ1 question 32b.

[637] Ex. 73 (DRA-5) p. 33, citing DRA-128-EJ1 question 32j.

[638] Ex. 18 (PG&E-4 workpapers), p. WP 5-49.

[639] Ex. 73 (DRA-5), p. 33.

4.5.1.4 MWC KC – Electric Distribution Maintenance Network

PG&E records its expenses for network activities and projects in MWC KC. This includes network notifications, transformer oil sampling and oil replacement, network protector maintenance, and other maintenance work.[640] PG&E forecasts $5.992 million in expenses for MWC BK.[641] After reviewing PG&E's testimony, workpapers, and discovery responses, DRA agrees with PG&E's request.

4.5.1.5 MWC BK – Maintenance Other Equipment

PG&E records its expenses for Distribution Line Equipment Overhauls in MWC BK. Repairs and overhauls for distribution line equipment extend the useful service life of equipment such as transformers, voltage regulators, circuit reclosers, capacitor banks, and line switches.[642] PG&E forecasts $2.713 million in TY expenses for MWC BK.[643] After reviewing PG&E's testimony, workpapers, and discovery responses, DRA agrees with PG&E's request.

4.5.2 Capital Expenditures

4.5.2.1 MWC 2A – Install and Replace Overhead

Major Work Category 2A is comprised of twelve subprograms: (1) Total Cost of Overhead Notifications; (2) Total Costs of Overhead Critical Operating Equipment (COE) Notifications; (3) Total Cost of Bird Sale and Bird Retrofits Notifications; (4) Idle Facilities Removal; (5) Major Notifications; (6) Non Exempt Equipment Replaced in UWF-Cap; (7) SF Incandescent Streetlights; (8) Permit Updates; (9) Infrared Switch Replacement; (10) Infrared Reconductor; (11) Escalation; and, (12) LED Streetlight Replacement.[644] DRA's recommendations are set forth below.

Total Cost of Overhead Notifications

PG&E schedules and executes maintenance notifications based on regulatory requirements, equipment condition, climate condition, equipment design, and third party

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[640] Ex. 17 (PG&E-4), p. 5-27.

[641] Ex. 18 (PG&E-4 workpapers), p. WP 5-1.

[642] Ex. 17 (PG&E-4), p. 5-33.

[643] Ex. 18 (PG&E-4 workpapers), p. WP 5-1.

[644] Ex. 18 (PG&E-4 workpapers), p. WP 5-25. Lines 13-30, and Ex 17 (PG&E-4), p. 19-1. LED Streetlights are discussed below in Section 4.19 of this Opening Brief.

actions.[645] In 2010, PG&E began implementing a new system for prioritizing notifications and a plan to eliminate the backlog by the end of 2013. PG&E's objective was to complete newly identified notifications for abnormal conditions within 12 month. Thereafter, PG&E's forecast for 2014 and beyond would be for newly identified work to preserve a steady flow.[646]

PG&E requested a three-year total of $128.3 million. DRA agrees with this three-year total amount. 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 3-year total from 2012-2014 equals PG&E's forecasted 3-year total. Therefore, DRA recommends capital expenditures of $54.4 million for 2012, $37.9 million for 2013, and $31.5 million for 2014.[647]

Total Cost of Overhead Critical Operating Equipment (COE) Notifications

These costs address inoperative equipment that is very important to the operation and functionality of the electric distribution system. This equipment, includes fuses, interrupters, reclosers, sectionalizers, switches, and disconnects, plays a major role in preventing customer interruptions and is critical for restoring power after an outage. PG&E forecasts the unit costs and number of units for 2014 to be higher than 2011 due to changes in the COE process to include additional assets, improve time for repair and decrease equipment downtime.[648]

In 2010, PG&E began implementing a new system for prioritizing notifications. Under the new prioritization system, PG&E's objective is to complete newly identified notifications for abnormal conditions within 12 months and to eliminate existing backlog by the end of 2013. The increase in 2011 notifications completed relative to 2010 reflects a full year of completing backlog notifications and steady state notifications.[649]

PG&E requested a three-year total of $52.0 million. DRA agrees with this three-year total amount. 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

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[645] Ex. 17 (PG&E-4), p. 5-3 through 5-5, lines 27-13.

[646] Ex 17 (PG&E-4), p. 5-18, lines 4-10.

[647] Ex. 76 (DRA-8), p. 19.

[648] Ex. 17 (PG&E-4), pp. 5-18 & 5-19, lines 20-2

[649] Ex. 76 (DRA-8), p. 19 citing PG&E's response to data request DRA-PG&E-040-MKB, Q. 6.a.

and 2014 forecast so that DRA's 3-year total from 2012-2014 equals PG&E's forecasted 3-year total. Therefore, DRA recommends capital expenditures of $22.4 million for 2012, $14.8 million for 2013, and $14.8 million for 2014.[650]

4.5.2.2 Total Cost of Bird Safe and Bird Retrofit Notifications

In order to comply with various state and federal laws including the migratory Bird Treaty Act, Bald and Golden Eagle Protection Act, Endangered Species Act, and state game codes, PG&E, in conjunction with USFWS, has developed the Avian Protection Plan (APP). The APP requires PG&E to take corrective action if a migratory bird is electrocuted as a result of PG&E's facilities (reactive based work). From a proactive perspective, the APP also requires retrofits for a minimum of 2,000 poles annually.[651]

PG&E's plan to retrofit 2,000 poles can be either expensed or capitalized. In 2010, PG&E capitalized 886, and in 2011, PG&E capitalized 897 poles. PG&E plans to capitalize 1,025 poles a year in 2012-2014.[652]

PG&E requested a three-year total of $9.7 million. DRA agrees with this three-year total amount. 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 3-year total from 2012-2014 equals PG&E's forecasted 3-year total. Therefore, DRA recommends capital expenditures of $5.3 million for 2012, $2.2 million for 2013, and $2.2 million for 2014.[653]

4.5.2.3 Idle Facilities Removal

PG&E is forecasts $6.4 million in 2012, $22.9 million in 2013 and $26.6 million in 2014 for capital expenditures for Idle Facilities Removal.[654] PG&E's 2014 forecast is a 72,800% increase in capital expenditures over its 2011 recorded levels. DRA recommends capital expenditures of 3,000 for 2012, $102,200 for 2013, and $101,200 for 2014.[655]

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[650] Ex. 76 (DRA-8), p. 20.

[651] Ex. 17 (PG&E-4), p. 5-20, lines 3-14

[652] Ex. 18 (PG&E-4 workpapers), p. WP 5-10, line 4.

[653] Ex. 76 (DRA-8), p. 21.

[654] Ex. 18 (PG&E-4 workpapers), p. WP 5-26.

[655] Ex. 76 (DRA-8), p. 22.

Removing idle facilities has been low priority work for PG&E.[656] PG&E performed no cost benefit study or engineering study on removing idle facilities, and did not identify any idle facilities it plans on removing in 2012-2016.[657] Without specific plans, PG&E has failed to adequately support its request.

During the last five years (2007-2011) PG&E's idle facility removal capital expenditures recorded in MWC 2A had wide fluctuations from ($7,800) in 2009 to $467,000 in 2008. Given PG&E's lack of support for its forecasts for 2013 and 2014, DRA recommends the use of a five-year average (2007-2011) for PG&E's Idle Facility Removal capital expenditures in 2013 and 2014. This results in capital expenditures of $3,000 for 2012, $102,200 for 2013, and $101,200 for 2014.[658]

4.5.2.4 Major Notifications

Major Notifications are unit based work that is more complex and costly in nature and is therefore transferred from unit tracked work to Major notifications. While PG&E makes every effort to identify these notifications prior to allocation, the scope and breadth of some notifications changes due to conditions in the field, cost of equipment, and circumstances discovered after initial assessment. Forecasted costs are based on historical movement of unit based work adjusted for 2011 which reflects a considerably higher volume of transfers to major notifications.[659]

Because PG&E's Proposed 2013 and 2014 capital expenditures are lower than historical Major Notification capital expenditures, DRA agrees to PG&E's forecasts for MWC 2A, Major Notifications capital expenditures for the years 2013 and 2014 at this time.

4.5.2.5 SF Incandescent Streetlights

PG&E forecasts $7.250 million in 2012 and 2013 and $7.240 million in 2014 for SF incandescent streetlight replacements.[660] DRA recommends the Commission adopt $2.85 million for 2013 and for 2014.[661]

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[656] Ex. 17 (PG&E-4), p. 5-21, lines 9-12.

[657] Ex. 76 (DRA-8), p. 21 citing PG&E's response to data request DRA-PG&E-040-MKB, Q. 12.g.

[658] Ex. 76 (DRA-8), p. 22.

[659] Ex. 18 (PG&E-4 workpapers), p. WP 5-25, footnote 6.

[660] Ex. 17 (PG&E-4), p. 5-42.

PG&E owns approximately 1,180 incandescent streetlights in San Francisco. These incandescent lights date back prior to 1957 and replacement parts are not being manufactured, which makes it difficult to keep these lights operating. PG&E purportedly has a commitment to the City and County of San Francisco to replace these facilities. PG&E is replacing the existing lights with more conventional means of lighting such as high pressure sodium 120 volt lighting. It will be necessary to replace associated transformers and cables. The three-year plan for incandescent streetlights would replace obsolete equipment such as fixtures, transformers and cable for streetlight facilities primarily located in San Francisco. PG&E claims that the replacement work will begin in 2012 and will end in 2014.[662]

PG&E based its estimate of $18,421 per light replaced, on a 2009 project where PG&E replaced 19 lights. PG&E also expects to change over almost 400 lights per year.[663] In 2012, PG&E only changed 22 lights.[664]

When PG&E does begin this project in earnest, its costs should drop drastically. At this time, PG&E has not been able to support its outdated 2009 cost, or its forecast costs. DRA recommends the Commission adopt $2.85 million a year for 2013 and 2014, an amount equal to PG&E's 2012 SF incandescent light replacement capital expenditure. DRA's forecast reflects PG&E's most recent capital investment while providing funding for the project over a more reasonable and realistic time horizon.

4.5.2.6 Permit Updates

PG&E requested a three-year total of $700,000 for permit updates to maintain its right of ways for easements in the United States Forest Service lands.[665] DRA agrees with this three-year total amount. PG&E's actual 2012 capital expenditures exceeded its forecasted 2012 expenditures, and DRA accepts the 2012 actual expenditures. DRA adjusted its 2013 and 2014 forecast so that DRA's 3-year total from 2012-2014 equals PG&E's forecasted 3-year total.

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[661] Ex. 76 (DRA-8), p. 23.

[662] Ex. 17 (PG&E-4), p. 5-37, lines 3-15.

[663] Ex. 18 (PG&E-4), p WP 5-30, Cost Assumption section.

[664] Ex. 76 (DRA-8), p. 23 citing PG&E's response to data request DRA-PG&E-213-MKB, Q. 2.d.

[665] Ex. 73 (DRA-8), p. 23 citing PG&E's response to data request DRA-PG&E-040-MKB, Q. 11.a.

Therefore, DRA recommends capital expenditures of $565,000 for 2012, $67,500 for 2013, and $67,500 for 2014.

4.5.2.7 Infrared Reconductor and Infrared Switch Replacement

PG&E is requesting $15.750 million in 2014 for infrared reconductor and infrared switch replacement.[666] DRA recommends no ratepayer funding for this project.

PG&E says the purpose of PG&E's comprehensive infrared and splice inventory program is to identify connectors, splices and switches that require replacement or repair. The capital component of the program involves addressing overhead spans that contain more than two in-line splices and switches that have been identified for replacement.[667]

There are no government requirements that PG&E perform infrared inspections over any cycle.[668] PG&E has not conducted an infrared inspection of its entire system in the past 20 years.[669] PG&E does not maintain separate data for overhead switch replacements, nor does it keep records of the number of splices it replaced on a year by year basis.[670] PG&E also could not identify any cost benefit studies or engineering studies that supported its program request.[671]

PG&E has not shown that the infrared conductor and infrared switch replacement program requested is cost effective, could not identify conductors or switches failing, and has not shown that this program is in ratepayers' best interest. Therefore, DRA recommends against PG&E receiving any funding for its infrared conductor and infrared switch replacement program.[672]

4.6 Pole Test and Treat, Restoration and Joint Utilities Coordination

PG&E's Pole Test and Treat, Restoration and Joint Utilities Coordination programs maintain PG&E's expansive system of distribution poles. PG&E forecasts $16.177 million for

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[666] Ex. 17 (PG&E-4), p. 5-42, lines 7 & 8.

[667] Ex. 17 (PG&E-4), p 5-36, lines 21-29C.

[668] Ex. 76 (DRA-8), p. 24 citing PG&E's response to data request DRA-PG&E-040-MKB, Q. 14.a.i.

[669] Ex. 76 (DRA-8), p. 24 citing PG&E's response to data request DRA-PG&E-040-MKB, Q. 14.a.iii.

[670] Ex. 76 (DRA-8), p. 24 citing PG&E's response to data request DRA-PG&E-040-MKB, Q. 14.b.i.

[671] Ex. 76 (DRA-8), p. 24 citing PG&E's response to data request DRA-PG&E-040-MKB, Q. 14.e & f

[672] Ex. 76 (DRA-8), p. 25.

TY2014 program expenses. This is an increase of $9.567 million or 146.06 % over 2011 expenses.[673]

DRA's estimate for PG&E's pole-related expenses is $12.267 million, which is $3.85 million less than PG&E's forecast of $16.117 million. DRA's TY estimate is $5.717 million more than PG&E's 2011 recorded adjusted expenses of $6.550 million.[674]

4.6.1 MWC GA – Poles – Inventory/ Test & Treat

PG&E records expenses for its Pole Test and Treat, Restoration and Joint Utilities Coordination Programs in Major Work Category (MWC) GA. PG&E says it developed its forecast based on the forecast units of work and the unit costs to perform the work.[675]

All poles in PG&E's electric distribution system are tested and treated on a continuous 10-year cycle. PG&E inspected 2.2 million poles during its first 10-year cycle from 1995-2004 and started its second cycle in 2005.[676]

In its Direct Testimony, PG&E stated that its 2014 expense forecast is $9.6 million higher than 2011 recorded costs "due to an increase in the forecast number of poles requiring work between 2012-2014 because the Company inspected fewer poles during 2009-2011 than prior years."[677] In order to maintain its 10-year cycle, PG&E plans to increase the number of poles inspected to 312,500 in 2014.

PG&E stated the reduction in pole inspections is "due to the reallocation of resources to other activities (e.g., emergency recovery)."[678] DRA asked PG&E to provide a list of the resources that was reallocated from MWC GA. PG&E was unable to provide this information.[679]

PG&E is responsible for crucial ongoing maintenance activities even if it chooses to reallocate its resources. PG&E's reduction in pole inspections from 2009-2011 is a result of

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[673] Ex. 17 (PG&E-4), p.6-1.

[674] Ex. 73 (DRA-5), p. 35.

[675] Ex.17 (PG&E-4), p. 6-13.

[676] Ex. 17 (PG&E-4), p.6-3.

[677] Ex. 17 (PG&E-4), p. 6-1.

[678] Ex. 17 (PG&E-4), p. 6-8.

[679] Ex. 73 (DRA-5), p. 38 citing DRA-033-EJ1 question 4.

deferred maintenance. PG&E routinely receives funding for ongoing and essential maintenance activities including maintenance on PG&E's system of electric distribution poles.

In the 2011 GRC, PG&E projected $16.462 million in expenses for MWC GA,[680] and the entire amount was adopted by the Commission.[681] PG&E's recorded expenses for 2011 were $6.550 million. PG&E's underspending of its 2011 forecast and Commission-authorized funding in MWC GA by $9.612 million was a discretionary decision of PG&E and has directly resulted in the current delayed pole test and treat work.[682]

This is not a one-time occurrence; PG&E has annually underspent its Commission-authorized expenses for MWC GA by millions of dollars for the past five years (2007-2011).[683] As noted above, the Commission has frequently ruled that utilities should not be permitted to recover expenses that were previously authorized, but deferred. This is especially true here.

Ratepayers should not be charged twice for routine and on-going maintenance work that was deferred by PG&E. PG&E's shareholders, and not ratepayers, should be responsible for these additional costs.

Pole Inspections

PG&E forecasts that it will inspect 312,500 poles in 2014, which is 93,981 poles or 43% higher than the 218,519 pole inspections conducted in 2011.[684]

Since the start of PG&E's second 10-year inspection cycle in 2005, the greatest number of pole inspections was 258,868 poles in 2012, which was still significantly higher than previous years.[685] In addition, both the 2012 number of poles and associated expenses for MWC GA were less than that forecasted by PG&E in the 2014 GRC Application.[686]

DRA also reviewed PG&E's first 10-year inspection cycle from 1995-2004. Only once, in 1997, did PG&E exceed an annual inspection of 264,745 poles during its first 10-year

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[680] Ex. 73 (DRA-5) p. 38 citing DRA-172-EJ1 question 2.

[681] Ex. 73 (DRA-5), p. 38 citing DRA-172-EJ1 question 3.

[682] Ex. 73 (DRA-5) p. 38 citing DRA-033-EJ1 question 4.

[683] Ex. 73 (DRA-5), p. 5, Table 5-2 "2007-2011 Authorized vs. Recorded Electric Distribution Expenses".

[684] Ex. 73 (DRA-5), p. 39, citing DRA-033-EJ1 Q/A 1.

[685] Ex. 73 (DRA-5), p. 40, Table 5-18.

[686] Ex. 18 (PG&E-4 workpapers), p. WP 6-7.

inspection cycle from 1995-2004. PG&E was also not able to "finish its first inspection cycle until a few months into the year 2005."[687] PG&E's own records demonstrate that there is no historical grounding for an unrealistic TY forecast of 312,500 pole inspections.

In Rebuttal, PG&E reduced its TY 2014 request to $15.050 million to account for additional joint pole credits.[688] This is still far more than ratepayers should be responsible for funding.

DRA proposes a TY2014 forecast of $12.267 million, the amount DRA estimates PG&E needs in order to inspect 235,000 poles in 2014. PG&E identified the number of poles that it plans to inspect in its second 10-year cycle as approximately 2.35 million; the number is generous and includes "inspections that cover new and removed poles" in addition to the "approximately 2.2 million wood poles in the PG&E system."[689] In order to maintain a 10-year inspection cycle, PG&E should annually inspect 235,000 poles.[690]

DRA's recommended forecast will cover these inspections and ensure that ratepayers only pay once for routine maintenance; shareholders should be responsible for expenses associated with backlogged poles and deferred maintenance. DRA's forecast for 235,000 poles is also much more realistic than PG&E's forecast of 312,500 poles based on the historical number of pole inspections, and represents a normalized test year forecast.

DRA developed its forecast by multiplying 235,000 poles by PG&E's forecast unit cost to perform a pole inspection.[691]

4.7 Pole Replacement

The Capital Expenditures related to the replacement of overhead poles are recorded in Major Work Category 07.

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[687] Ex. 73 (DRA-5), p. 40 citing DRA-172-EJ1 question 6.

[688] Ex. 55 (PG&E-10), p. 6-7.

[689] Ex. 73 (DRA-5), p. 41. DRA-223-EJ1 question 1.

[690] 2.35 million poles divided by 10 years is 235,000 poles per year.

[691] Ex. 73 (DRA-5), p. 41, footnote 105: (DRA developed its test year estimate using active Workpaper Table 6-7 provided by PG&E in response to DRA-172-EJ1 question 5. DRA input 235,000 poles under "Test & Treat Poles - Current Year" in order to forecast the number of pole inspections, strength and load calculations, and pole restorations, and the corresponding costs. DRA accepted all assumptions by PG&E other than annual pole inspections.

PG&E has full or joint ownership of approximately 2.2 million wood distribution poles.[692] These poles are inspected, and when necessary, restored or replaced. The numbers of poles replaced each year, as well as the unit cost to make the replacements, varies from year to year as well as from division to division within PG&E's service territory.

DRA is recommending that recorded 2012 capital expenditures of $119.316 million be used (versus PG&E's forecast of $155.704 million). For 2013 and 2014, DRA is recommending capital expenditures of $76.181 million and $69.541 million, respectively, while PG&E has forecasted expenditures of $159.798 million and $69.578 million.[693]

DRA's testimony shows a breakdown for the years 2007 through 2011 of how the authorized MWC 07 capital expenditures for each year compare to what PG&E actually spent.[694] As indicated at the bottom of the table, DRA has calculated that over that five-year period, PG&E has spent $206.529 million less than it was authorized for pole replacements.

In discussing the number of poles that it proposes to replace each year, PG&E states the following:

> The forecasted numbers of units for 2012 and 2013 reflect PG&E's effort to eliminate the current backlog of pole replacement work. By 2014, PG&E plans to reach a consistent level of pole replacement work.[695]

The above quotation explicitly states that there is currently a backlog of poles that need to be replaced. As discussed in DRA's testimony, PG&E stated in its last GRC that it sought higher MWC 07 expenditures in order to address pole replacements that had previously been rescheduled (i.e., deferred) due to a reallocation of funds to higher priority work.[696] In spite of the fact that a deferral of pole replacement expenditures has resulted in a backlog of replacements over two rate case cycles, PG&E has consistently spent less than the amount the Commission has authorized.[697]

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[692] Ex. 17 (PG&E-4), pp. 6-2, line 29.

[693] Ex. 75 (DRA-7), p. 20, Table 7-2, line 4.

[694] Ex. 75 (DRA-7), p. 21, Table 7-3.

[695] Ex. 17 (PG&E-4), p. 7-5, lines 12 through 14.

[696] Ex. 75 (DRA-7), Section V.

[697] Ex. 75 (DRA-7), p. 21, Table 7-3.

PG&E's pattern of under spending has continued into 2012. When DRA analyzed PG&E's RO computer model, DRA noted that PG&E was forecasting that it would spend $87.393 million in 2012 to help eliminate the pole replacement backlog. In a Data Request, DRA asked PG&E to provide the recorded amount that was actually spent to reduce the backlog. In its response, PG&E stated that its actual 2012 expenditures for backlog elimination amounted to $56.328 million, over $30 million less than it had forecasted.[698]

In its Rebuttal testimony for the pole replacement capital category PG&E states that it is not true that PG&E has consistently spent less than the Commission had authorized on Pole Replacements, noting that it had spent almost $30 million more than authorized in 2011.[699] DRA agrees that PG&E spent more than authorized in 2011, and noted that fact in Table 7-3 in its testimony.[700] However, that same table also shows that over the period 2007 through 2011, PG&E had cumulatively spent over $200 million less than what the Commission had authorized. By any reasonable definition of the word "consistently," DRA believes that the evidence shows that PG&E has been spending less that it was authorized for MWC 07 on an ongoing basis.

In Rebuttal, PG&E also claims that it actually spent $65 million more on Pole Replacements than the Commission authorized in 2012.[701] This is new information, and DRA cannot confirm that it is accurate. However, for the sake of argument, let's assume that the new information is correct. What exactly does that mean? If this "higher than authorized" expenditure level is the result of transferring expenditures from other capital projects to pole replacement projects, then PG&E is simply robbing Peter to pay Paul, and some other capital category is now being deferred. If, on the other hand, PG&E is not transferring funds from some other project, then that would indicate that PG&E is doing for 2012 what DRA is recommending for 2013, namely that the "catch-up" of pole replacement deferrals be undertaken without PG&E's customers being required to pay for it until the next rate case cycle begins.

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[698] Ex. 75 (DRA-7), p. 22 citing PG&E's response to DR DRA-086-GAW, Question 2c. $87.393 million requested in 2012 for backlog elimination minus $56.328 million actually spent equals $31.065 million underspent.

[699] Ex. 55 (DRA-19), p. 7-4.

[700] Ex. 75 (DRA-7), p. 21, Table 7-3.

[701] Ex. 55 (PG&E-19), p. 7-4, Q/A 10.

In Rebuttal, PG&E also states that it must be allowed to prudently manage its available resources to ensure a safe and reliable electric distribution system, even if that means deferring work so that higher priority work can be performed.[702] DRA agrees that PG&E should be allowed to prudently manage its system. However, DRA disputes the concept that prudent management should routinely allow unexpected projects to cause other necessary projects to be deferred.

As discussed in D.09-03-025, SCE's Test Year 2009 GRC, the Commission has ruled that it takes a unique set of circumstances before deferrals are appropriate. That decision specifically mentions the issues surrounding Y2K as being one-time events that justify deferrals. The decision also states that routine aspects of any rate case (such as unanticipated customer and load growth) do not warrant deferrals just because they are higher than anticipated.

As discussed in DRA's testimony, test year ratemaking sometimes means that a utility spends more than what was authorized. Deferring expenditures so as to maintain an authorized rate of return is nothing more than "gaming" the system.

4.8 Vegetation Management

PG&E's Vegetation Management Program patrols, inspects and maintains clearance on trees as required for regulatory compliance and removes vegetation (vegetation control) from around poles that have the potential to cause fires. PG&E also maintains or removes "hazard trees" or trees that it identifies as structurally unsound or that have the potential to fall on to power lines.

4.8.1 Expense

PG&E forecasts $190.0 million for Vegetation Management expenses for the Test Year 2014. This is an increase of $28.433 million, or 17.60%, over 2011 recorded adjusted expenses of $161.567 million.[703] The corresponding DRA estimate for PG&E's Vegetation Management expenses is $164.223 million, or $2.656 million more than PG&E's 2011 recorded adjusted expenses.

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[702] Ex. 55 (PG&E-19), p. 7-5, Q/A. 13.

[703] Ex. 17 (PG&E-4), p. 8-19, Table 8-1.

PG&E says it developed its forecast based on planned units of work and then multiplied the units of work by a calculated unit cost.[704] PG&E also used an Excel formula "GROWTH" non-linear estimation methodology to determine its forecasted unit cost and its planned units of work for the Test Year.[705]

4.8.1.1 MWC HN – Tree Trimming

PG&E records expenses for its Vegetation Management Program in MWC HN. PG&E's MWC HN includes individual forecasts for six line items/subaccounts. PG&E forecasted $156.0 million for Routine Tree Work, $8.7 million for Vegetation Control, $1.2 million for Quality Assurance, $0.360 million for Public Education, $12.591 million for Environmental Compliance and $11.113 million for Fire Risk Reduction.[706] The forecasts in dispute are for Routine Tree Work, Fire Risk Reduction, and Environmental Compliance.

Routine Tree Work

PG&E forecasted $156.0 million for its Routine Tree Work expenses, using an Excel GROWTH formula.[707] PG&E's forecast is an increase of $4.398 million over its 2011 recorded adjusted expenses. DRA recommends the Commission adopt PG&E's 2011 recorded adjusted expense level of $151.602 million for PG&E's Routine Tree Work.[708]

PG&E's expenses were relatively stable between 2007 and 2010 with an average for the four year period of $140.102 million. PG&E's 2011 recorded adjusted expenses for Routine Tree Work increased by $11.492 million between 2010 and 2011. PG&E's increase between 2010 and 2011 is due primarily to PG&E's expanded fire risk reduction work and tree trimming reliability projects. PG&E's 2011 recorded adjusted expenses for this line item is the highest

[704] Ex. 17 (PG&E-4), p. 8-27.

[705] Ex. 74 (DRA-6), p. 23.

[706] Ex. 18 (PG&E-4, workpapers), p. WP 8-6, Table 8-6.

[707] Ex. 17 (PG&E-4), p. 8-20.

[708] Ex. 74 (DRA-6), p. 25.

annual recorded figure for the five year period (2007-2011. PG&E's 2011 recorded adjusted expenses is a reasonable expense level for the Test Year.[709]

PG&E's Excel GROWTH formula forecasts a $4.398 million increase over 2011 recorded adjusted expenses for its Routine Tree Work. PG&E used the Excel GROWTH function to forecast its 2011 and 2010 expenses for Routine Tree Work.[710] In both instances, the Excel GROWTH formula overestimated PG&E's actual recorded expenses.

On the other hand, DRA's forecasts for PG&E's entire Vegetation Management Programs have proven to be much closer to PG&E's actual spending. In 2011, PG&E's spending for its entire Vegetation Management Program was $161 million. DRA's forecast was $160 million.

PG&E states that its contractor costs are overwhelmingly the largest single component of its Vegetation Management program and that these costs are increasing. PG&E attributes this to increasing health care costs, liability insurance premiums, worker compensation costs, and decreased productivity due to increased travel time between fewer work locations.[711]

In its last GRC, PG&E made the same arguments to support its requested increase there too.[712] As noted above, PG&E's TY 2011 forecast was overstated by $0.898 million. In 2012, PG&E spent less on its entire Vegetation Management program than it did in 2011, though it did not provide the information specific to Routine Tree Work.[713]

PG&E does not itself track its contractors' insurance, liability premiums, and workers compensation[714] and DRA cannot assume that specific costs are increasing over 2011 recorded adjusted expenses and require more ratepayer funding in the Test Year. DRA continues to recommend that the Commission adopt 2011 recorded adjusted expenses of $151.602 million for Routine Tree Work.

Fire Risk Reduction

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[709] Ex. 17 (DRA-6), p. 25.

[710] Ex. 74 (DRA-6), p. 26, footnote 54: PG&E's line item for Routine Tree Work in its 2014 GRC, was called Routine Tree Trimming and Removal in PG&E's 2011 GRC.

[711] Ex. 17 (PG&E-4), p. 8-19.

[712] Ex. 74 (DRA-6), p. 27, lines 18-25.

[713] Ex. 74 (DRA-6), p. 23 Table 6-9 and footnote 48.

[714] Ex. 74 (DRA-6), p. 23 citing PG&E's response to DRA-PG&E-083-TLG Q.1-g.

PG&E forecasts $11.113 million for its Fire Risk Reduction program expenses.[715] DRA recommends no additional ratepayer funding for this proposal.[716]

PG&E says that the additional funding is for its inspectors to conduct "a more detailed evaluation of every tree that has the potential to fall into PG&E's lines in selected highest fire risk locations…"[717] PG&E shows no recorded spending at all for this Fire Risk Reduction program in the years 2007-2011, though in PG&E's 2011 GRC, PG&E requested additional funding of $13.0 million for it. In the TY 2011 GRC, DRA recommended additional funding of $4.3 million for that work.[718]

In this GRC, PG&E says that the reason there are no recorded costs for the Fire Risk Reduction program for 2011 is because "PG&E's current work to reduce the risk of fires is recorded as part of its Routine Tree Work, so therefore does not appear as Fire Risk Reduction work for 2011-2013 in Table 8-1."[719] Similarly, in its TY 2011 GRC, PG&E did not show any historical expenses recorded for its Fire Risk Reduction work for the years 2004-2008 even though PG&E argued that it had been performing fire risk reduction work as part of its on-going and routine maintenance activities.[720]

From its testimony in the last GRC, and responses to data requests in this one, it appears that PG&E has been performing Fire Risk Reduction work for several years, in particular, assessing trees for "possible removal [of trees] that could fall into its power lines in selected locations." PG&E's response does not address incorporation of embedded costs for on-going and routine activities that are similar to activities that will be performed in the Test Year. Nor has PG&E provided any documentation showing that the current funding level for its fire risk reduction work is insufficient.

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[715] Ex. 18 (PG&E-4, workpapers), p. WP 8-6, Table 8-6.

[716] Ex. 74 (DRA-6), p. 28.

[717] Ex. 17 (PG&E-4), p. 8-18.

[718] Ex. 74 (DRA-6), p. 28.

[719] Ex. 74 (DRA-6), p. 29, footnote 62 citing DRA-PG&E-083-TLG Q.1-b.

[720] Ex. 74 (DRA-6), p. 29, footnote 63: Ex. (PG&E-3, Table 5-4 p. 5-20. PG&E stated in its 2011 GRC that "PG&E began a program in mid-2006 to reduce the risk of fires by removing overhanging branches in urban areas as part of its routine tree trimming and removal program. The recorded expenses for the program were $7.0 million in 2007 and $10.4 million in 2008" (Exhibit (PG&E-3) p. 5-27).

In Rebuttal, PG&E says it has proposed this "new" Fire Risk Reduction program in order to improve public safety and service reliability. According to PG&E, the "… new Fire Risk Reduction program work is needed to further reduce fire risk in Northern California and complements the CPUC's own emphasis on fire-risk reduction efforts…"[721] Obviously, fire risk reduction is a worthy goal, but PG&E's approach always seems to be to ask for more ratepayer money, rather than to use the ratepayer funding it already gets more productively.

A case in point is the Orleans/Somes Bar Fire Safe Council. Since at least 2009, a group called the Orleans/Somes Bar Fire Safe Council (OSB FSC) has been trying to get PG&E to address the fact that "…periodic brushing and trimming work done under PG&E power lines contributes to a fuel build –up and an extreme fire hazard to private property as well as risks of wildland fire on Forest Service land."[722] The OSB FSC has received funding from the US Forest Service, CALFIRE, Bureau of Land Management and others to implement strategic fuel reduction projects on over 1000 acres of private property since 2001.

In September 2009, the OSB FSC proposed several constructive ideas to PG&E. These included the following:

> 1. Provide funding for OSB FSC to clean up accumulated fuels in power line easements, after contractors are done with their maintenance activities. This could be done either by chipping or by dragging materials out of easements in order to burn.
> 2. Provide capital funding for private landowners to install permanent easement maintenance systems such as fencing for livestock, or gardens. In this case the Fire Safe Council could facilitate and monitor such projects.
> 3. Provide funding for OSB FSC chipping services and other operating costs. We own a chipper but could use assistance for equipment maintenance, fuel and wages in order to provide this important service to landowners in need of fire safe treatments.[723]

It does not appear that PG&E has put any of the suggestions in this letter or in succeeding communications from the Orleans /Somes Bar Fire Safe Council into practice. This year, PG&E

[721] Ex. 55 (PG&E 19), p. 8-9.

[722] Ex. 205, Letter dated September 17, 2009.

[723] Ex. 205, Letter dated September 17, 2009.

made a charitable donation to the OSB FSC, but that is hardly the same thing.[724] Instead of continually asking for more ratepayer funding, this time, $11.3 million in 2014, PG&E could use the embedded funding it already has to work with stakeholders like OSB/ FSC to reduce fire risk more effectively than it has done to date.

Environmental Compliance

PG&E forecasts $12.591 million for Environmental Compliance expenses for the Test Year. This is an increase of $12.276 million, or 3,896% over its 2011 recorded adjusted expenses of $315,000. DRA recommends the Commission adopt a Test Year estimate of $2.361 million. DRA normalized half of PG&E's forecast over the three year rate case cycle to arrive at additional funding of $2.046 million over 2011 recorded adjusted expenses.[725]

PG&E says it needs additional funding for screening, surveying and monitoring, permitting, mitigation, staff and Vegetation Control erosion mitigation.[726] DRA's recommended $2.361 million should be more than adequate for PG&E to address its Environmental Compliance obligations in the Test Year.

In PG&E's TY 2011 GRC, PG&E requested additional funding of $3.0 million for Environmental Compliance expenses.[727] DRA disputed PG&E's forecast and recommended additional funding of $1.0 million.[728] In 2011, PG&E spent $314,000 on Environmental Compliance, less than both PG&E's forecast and DRA's.

PG&E has been incurring costs for screening, surveying and monitoring, permitting, mitigation, additional staffing and Vegetation Control erosion mitigation during the historical period (2007-2011). The activities PG&E describes in its testimony are not new, but are part of PG&E's on-going, normal and routine maintenance activities that are already funded by ratepayers. PG&E has embedded historical costs that it can reallocate and use in the Test Year for its Environmental Compliance activities.

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[724] 18 RT 2012—2014, Dominguez/PG&E.

[725] Ex. 74 (DRA-6), p. 31.

[726] Ex. 17 (PG&E-4), pp. 8-3, 24.

[727] Ex. 74 (DRA-6), p.32, PG&E's 2011 GRC forecast for its Environmental Compliance line item was included in its Ex. (PG&E-3) Table 5-4, p. 5-20 to A.09-12-020.

[728] Ex. 74 (DRA-6), p. 32, footnote 67: Ex. DRA-5, p. 50 on PG&E's 2011 GRC forecast on Vegetation Management Expenses recorded in MWC HN, in A.09-12-020.

During a vegetation management field tour, PG&E informed DRA of increasing restrictions, procedures and complications being encountered by PG&E relating to the environmental concerns from other stakeholders about specific areas and permitting guidelines associated with removing trees identified by PG&E as "hazard trees". It is possible that additional projects for the above mentioned issues could increase costs over 2011 recorded levels, and DRA's recommendation takes that into account.

In Rebuttal, PG&E says that "PG&E's historical costs for this activity are not indicative of its future costs because, as described below, PG&E expects to perform significantly more environmental compliance work going forward than in the past."[729] PG&E said the same thing in the last GRC and spent all of $315,000 on Environmental Compliance costs.[730]

DRA continues to recommend that the Commission adopt an estimate of $2.361 million for PG&E's Environmental Compliance in Test Year 2014.

4.8.2 Balancing Account and Tracking Account

PG&E also requests continuation of its Vegetation Management one-way balancing account.[731] DRA does not oppose this request.[732]

4.9 New Business and Work at the Request of Others

4.9.1 Expense

The New Business (NB) and Work at the Request of Others (WRO) program consists of work that PG&E performs at the request of its customers and other facilities.[733] PG&E forecasts $21.231 million for TY2014 NB/WRO expenses, which is an increase of $6.016 million or 39.54% over 2011 expenses of $15.215 million.[734] The NB/WRO program is recorded in two Major Work Categories (MWCs): EV for New Business with a forecast of $10.781 million, and NB for Work at the Request of Others with a forecast of $10.450 million.[735] The corresponding

[729] Ex. 55 (PG&E-19), p. 8-11.

[730] 18 RT 2019, Dominguez/PG&E.

[731] Ex. 17 (PG&E-4), p. 8-26.

[732] Ex. 74 (DRA-6), p.23.

[733] Ex. 17 (PG&E-4), p. 9-1.

[734] Ex. 18 (PG&E-4 workpapers), p. WP 9-1.

[735] Ex. 18 (PG&E-4 workpapers), p. WP 9-1.

DRA estimate for NB/WRO expenses is $19.393 million, which is $1.848 million less than PG&E's TY forecast of $21.231 million.

4.9.1.1 MWC EV –Manage Service Inquiries

PG&E records expenses for new business in MWC EV. New Business consists of the work required to connect new customers to both the electric and gas distribution system as well as provide additional load to existing customers.[736]

PG&E forecasts $10.781 million for TY2014 NB/WRO expenses, which is an increase of $4.587 million or 74.06% over 2011 expenses[737] The corresponding DRA estimate for MWC EV is $8.933 million, which is $1.848 million less than PG&E's 2014forecast. DRA's TY estimate is $2.739 million or 44.22% higher than PG&E's 2011 recorded expenses of $6.194 million, and $2.095 million or 30.64 % higher than PG&E's 2012 recorded expenses of $6.838 million.[738]

PG&E organizes work within MWC EV into two Maintenance Activity Type (MAT) codes: MAT EVA for Service Inquiry for New Customers and MAT EVB for OK to Serve for Existing Customers.

4.9.1.2 MAT EVA – New Business Service Inquiry

MAT EVA records expenses for new customer connections. PG&E forecasts $5.500 million for TY2014 EVA expenses, which is an increase of $2.679 million or 94.96% over 2011 expenses of $2.821 million.[739] The corresponding DRA estimate for MAT EVA is $4.900 million.[740]

PG&E's says its forecast is driven by the total number of service applications anticipated in 2014. PG&E's forecast for service applications is calculated using the total forecasted gas and electric connects divided by the average ratio of connects to applications over the past three years.[741] PG&E used new building permit and housing start forecast data from Moody's Investor

[736] Ex. 17 (PG&E-4), p. 9-1.

[737] Ex. 18 (PG&E-4 workpapers), p. WP 9-2.

[738] Ex. 73 (DRA-5), p. 43.

[739] Ex. 18 (PG&E-4 workpapers), p. WP 9-8.

[740] Ex. 73 (DRA-5), p. 44.

[741] Ex. 17 (PG&E-4), p. 9-11.

Service (Moody's)/Economy.com and IHS Global Insight to forecast new residential and non-residential connections in the distribution system.[742]

DRA developed its forecast using the 2012 ratio of connects to applications. PG&E's forecasted ratio of connects to applications is 2.9, signifying that for every 2.9 gas or electric connections made to the distribution system, PG&E anticipates there will be 1 service application processed. PG&E developed the ratio of 2.9 using a 3-year average of connects to applications (2009-2011). DRA's corresponding ratio of connects to application is 3.3, which is the 2012 ratio of connects to applications. DRA recommends the Commission use this number because it reflects the most recent data and market conditions.

DRA's forecast of $4.900 million for MAT EVA is $2.079 million or 73.70% greater than PG&E's 2011 recorded adjusted expenses of $2.821 and is sufficient for PG&E to address an increase in business service inquiries.

4.9.1.3 MAT EVB – OK to Serve

MAT EVB work records expenses for existing customers who need additional load or upgraded services. The base forecast for MAT EVB uses the average annual percent change in PG&E's electric customer base.[743] DRA agrees with PG&E's forecast of $3.100 million in expenses for base MAT EVB work that is not associated with Plug-in-Electric Vehicles expenditures.

4.9.1.4 MAT EVB – Ok to Serve/ PEV Related

PG&E separately forecasts expenses associated with added load service requests involving the purchase of Plug-in-Electric Vehicles (PEVs). PG&E forecasts $1.900 million for PEV-related work, which is $1.600 million or 533.33% greater than the 2011 recorded adjusted expense of $0.300 million.[744] The corresponding DRA estimate for MAT EVB is $0.700 million.[745]

The forecast for MAT EVB was developed by multiplying the number of PEV applications processed by the estimated cost to process each application. In order to do so,

[742] Ex. 17 (PG&E-4), p. 9-5.

[743] Ex. 17 (PG&E-4), p. 9-12.

[744] Ex. 18 (PG&E-4 workpapers), p. WP 9-10.

[745] Ex. 73 (DRA-5), p. 45.

PG&E developed TY2014 forecasts for the following items: PEV sales, application rate, and cost-per-application processing.[746]

DRA adjusted PG&E's forecasted application rate. PG&E forecasted that 100% of PEV consumers would start contacting PG&E directly upon purchase of an electric vehicle and therefore, the number of PEV Applications processed would be the same as the number of PEV Sales. DRA asked PG&E to explain why the application rate for PEV load requests was forecasted to increase in 2012 and to identify the 2012 application rate.

PG&E responded:

> Starting in 2012, PG&E reached agreements with both General Motors and Nissan to provide customer information on electric vehicle sales, but with an opt-out provision for customers who do not wish to have this information released. Even with this additional information source, PG&E only identified 38 percent of all electric vehicle sales in 2012 on which to perform load checks (2,264 assessments on 6,000 vehicle purchases). PG&E continues to pursue additional avenues, including California Department of Motor Vehicle information, to identify new electric vehicles and ownership transfers to improve load assessment rates."

PG&E's agreements with General Motors and Nissan did not increase the application rate to 100%, as PG&E anticipated. In fact, the application rate lowered from 40% in 2011 to 38% in 2012. While "PG&E continues to pursue additional avenues… to identify new electric vehicles and ownership transfers to improve load assessment rates," it is not clear what these additional avenues are, when they will be implemented, or how effective they will be. There is currently no evidence that the application percentage will change over the next couple of years. Therefore, DRA uses the 40% application rate in developing its TY forecast.[747]

DRA also made a minor adjustment to PG&E's forecasted PEV sales. PG&E forecasted the 2014 number of PEV sales to be 6,300 PEVs; the sales data was supplied by PG&E's Emerging Market and Technologies Department.[748] DRA asked PG&E to identify the number of PEV sales in 2012. PG&E estimated, based on Clean Vehicle Rebate Project reported rebates,

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[746] Ex. 18 (PG&E-4 workpapers), p. WP 9-10.

[747] Ex. 73 (DRA-5), p. 46.

[748] Ex. 18 (PG&E-4 workpapers), p. WP 9-10.

that 2012 PEV sales in PG&E's service were 6,000 PEVs.[749] Despite uncertainty in the PEV market, DRA uses 6,000 PEV sales in developing its TY2014 forecast.

The growth of the PEV market and associated costs remains largely uncertain. PG&E provided DRA with a copy of the "Joint IOU Electric Load Research Final Report," which was filed on December 28, 2012.[750] The report was compiled in response to D.11-07-029, which ordered PG&E, San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) to evaluate service upgrade costs associated with the PEV load.[751] Data supporting the report was tracked from June 2011 to October 2012.

The report concluded that thus far there is little evidence that added PEV load increases service upgrade costs. The report stated: "Through monitoring service upgrade costs due to new PEV load, the IOUs have determined the costs are currently insignificant". In regards to PG&E, "PG&E acknowledges that the PEV customer specific costs to date have been *de minimus,* but believes that it is too early to understand what the potential magnitude of upgrade costs might be given further EV penetration."[752] There is little indication that PEV-related costs will increase drastically over the next few years. DRA's forecast of $0.700 million, which more than doubles PG&E's recorded expenses from 2011, is reasonable and should be adopted by the Commission.

4.9.1.5 MWC EW – Work at the Request of Others -- Maintenance

PG&E records expenses for Work at the Request of Others (WRO) in MWC EW. WRO is work required by tariffs and franchise agreements and covers relocations, interconnection services, and pre-parallel inspections.[753] PG&E forecasts $10.450 million for TY EW expenses, which is an increase of $1.429 million or 15.84% over 2011 expenses of $9.021 million.[754] After

[749] Ex. 73 (DRA-5) p. 47 citing DRA-181-EJ1 question 11a.

[750] Ex. 73 (DRA-5), p. 47 citing DRA-181-EJ1 question 11b.

[751] "Joint IOU Electric Vehicle Load Research Final Report" filed on December 28, 2012. R.09-08-009 Ordered in D.11-07-029. P. 3.

[752] "Joint IOU Electric Vehicle Load Research Final Report" filed on December 28, 2012. R.09-08-009 Ordered in D.11-07-029. P. 4.

[753] Ex. 17 (PG&E-4), p. 9-13.

[754] Ex. 18 (PG&E-4 workpapers), p. WP 9-1.

reviewing PG&E's testimony, workpapers, and discovery responses, DRA agrees with PG&E's TY2014 forecast for MWC EW.

4.9.2 Capital Expenditures

4.9.2.1 MWC 10

MWC 10 is one of the two Corresponding capital expenditures for Work at the Request of Others. DRA's divides its capital expenditure section for MWC into two parts, with the instant section being the first.

Under its obligation to serve requirements, its tariff rules, and its franchise agreements with local governments, PG&E is required to perform various capital projects as part of MWC 10 -- Work at the Request of Others (WRO). Typical WRO projects include relocating electric distribution and service facilities at the request of a governmental agency or other third party, and overhead electric facility underground conversions covered by Tariff Rules 20B and 20C.[755]

DRA is recommending that recorded 2012 capital expenditures of $110.725 million be used (versus PG&E's forecast of $69.700 million). For 2013 and 2014, DRA is recommending capital expenditures of $81.496 million and $88.818 million, respectively, while PG&E has forecasted expenditures of $83.290 million and $96.465 million.[756]

As discussed by DRA in its testimony, and as shown on Table 7-4 (page 25) of Exhibit 75, DRA has proposed two adjustments to MWC 10. The first, shown on line 1 of Table 7-4, is actually linked to MWC 16. DRA and PG&E are both using the same methodology to derive their line 1 forecasts; differences are due solely to different estimates being calculated in MWC 16, which will be discussed in Part 2 of this section.

DRA's other major adjustment to MWC 10 involves scaling back PG&E's forecast for work related to the high-speed rail system. DRA is not attempting to critique or judge the reasonableness of the High-Speed Rail project. DRA is simply stating that the start of the project has already been delayed by half a year, and seems likely to be delayed significantly longer. Given these delays, it is DRA's judgment that PG&E will spend considerably less than it originally forecasted in 2014 for MWC 10 costs associated with the High-Speed Rail project.

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[755] Ex. 17 (PG&E-4), p. 9-28, lines 3 through 7.

[756] Ex. 75(DRA-7), p. 25, Table 7-4, line 11.

PG&E's 2014 forecast of $10.000 million should be reduced by half, corresponding to the six-month delay in the start of construction.

In PG&E's Rebuttal of DRA's high-speed rail recommendation, PG&E alleges that DRA's proposed adjustment for the high-speed rail project is an example of DRA selectively choosing one of thousands of projects in order to come up with a lower forecast.[757] PG&E further alleges that if DRA is allowed to selectively reduce projects, then PG&E should be allowed to increase the forecasts for other projects where the scope has increased.

Both of PG&E's allegations are completely baseless. As PG&E itself shows, there are not "thousands" of projects, but only 3 large specific projects that are included in WRO.[758] Of those 3, DRA accepted PG&E's forecasts for 2 of them, having uncovered no evidence that they were unreasonable. However, for the High-Speed Rail project, DRA discovered that the project had already been delayed ½ year, and was likely to be delayed even more. In its Rebuttal, PG&E does not dispute that there has been a delay. One of DRA's mandates is to evaluate the reasonableness of expense and capital forecasts used to develop proposed revenue requirements in GRCs. DRA would be negligent if it ignored evidence that a proposed capital expenditure was unreasonable. Contrary to PG&E's claim of "selectively choosing" a project, DRA investigated all 3 projects, and found 1 (the High-Speed Rail project) that should be adjusted.

PG&E's other allegation (that it be allowed to increase the forecasts of projects that have had costs increase) would result in a massive revision of the GRC process.

What PG&E is basically proposing is that the GRC be broken down into several new phases – after DRA issued its testimony, PG&E would initiate another phase of the GRC where PG&E would be allowed to revise its test year forecasts. This would then trigger another round of investigations by the various parties in order to determine whether or not these revised capital forecast were reasonable. PG&E's ill-advised proposal would cause the entire GRC process to come to a grinding halt.

As stated above, one of DRA's mandates is to evaluate the reasonableness of expense and capital forecasts used to develop proposed revenue requirements in GRCs. DRA would be negligent if it ignored evidence that a proposed capital expenditure was unreasonable. DRA has

[757] Ex. 55 (PG&E-19), p. 9-10, Q/A 37.

[758] Ex. 17 (PG&E-4), p. 9-35, Table 9-31.

done nothing more than evaluate the reasonableness of a proposed capital expenditure, and then recommend adjustments to that project based on the results of that evaluation. This evaluation process does not differ in any respect from countless capital investigations carried out by DRA (and its predecessors) over many decades involving hundreds (if not thousands) of GRC investigations. PG&E's misguided proposal should be quickly dismissed.

4.9.2.2 MWC 16

Similar to the mandates mentioned in MWC 10, PG&E is required under its obligation to serve requirements, its tariff rules, and its franchise agreements with local governments, to undertake various capital projects as part of its New Business Customer Connections program. The capital projects included in MWC 16 include installing electric infrastructure required to connect new customers to PG&E's electric distribution system, and upgrading its system to accommodate increased loads from existing customers.[759]

DRA is recommending that recorded 2012 capital expenditures of $234.589 million be used (versus PG&E's forecast of $210.000 million). For 2013 and 2014, DRA is recommending capital expenditures of $260.436 million and $317.369 million, respectively, while PG&E has forecasted expenditures of $272.545 million and $339.566 million.[760]

New Business capital expenditures are linked to overall economic growth and the resulting increase in new customers and electrical loads. If economic conditions are poor, fewer new houses tend to be built, resulting in fewer new connections. Similarly, existing customers will tend to postpone new purchases, resulting in lower load growth. PG&E's New Business costs decreased significantly during the recession, but have recently begun to increase. The difficulty in deriving forecasts for MWC 16 capital expenditures stems from the number of variables that can potentially impact the final estimate. Not only must estimates be made for the number of new connections each year, but estimates must also be made regarding how those new connections will impact subdivision backbone costs, subdivision costs, residential costs, and non-residential costs. DRA's testimony on this capital area is extensive and involves detailed calculations shown on Tables 7-5, 7-6, and 7-7 (on pages 29, 30, and 31 of Exhibit 75).

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[759] Ex. 17 (PG&E-4), p. 9-1, lines 13 through 15.

[760] Ex. 75 (DRA-7), p. 29, Table 7-5, line 9.

In PG&E's Rebuttal to DRA's MWC 16 recommendations, PG&E alleges that it is unreasonable for DRA to adopt an accelerated growth in residential connections, including subdivision service connections, without adopting a corresponding growth in subdivision backbone work which must precede the service connections.[761]

PG&E's allegation regarding inconsistencies in DRA's assumptions is not correct. It is perfectly plausible and completely reasonable to forecast an increase in subdivision connections at the same time that backbone connections are increasing at a lower rate. The recorded data for 2012 is a case in point. As shown in DRA's testimony, , subdivision connections increased from 5,836 in 2011 to 7,102 in 2012.[762] At the same time, backbone connections decreased from 3,577 in 2011 to 3,224 in 2012 (see line 6). In this example, backbone connections were actually decreasing (not merely increasing at a lower rate) as subdivision connections were going up. DRA has seen the same phenomenon in other utilities as well. During the recent economic downturn, unemployment increased, housing sales fell, and there was a glut of homes on the market. Developers stopped building homes, in many cases after subdivisions had already had the backbone facilities installed. Now that the economy is beginning to recover, developers are beginning to build-out subdivisions. However, there is no corresponding increase in backbone connections, as those are already in place. For 2013 and 2014, DRA is forecasting increased backbone connections, albeit at a rate that is lower than PG&E's forecast.

In Rebuttal, PG&E also says that recorded 2012 connections were higher than PG&E forecasted for residential subdivision service connects, other residential connects, and non-residential connects.[763] PG&E alleges that if DRA was consistent in its approach of using 2012 data as an indicator of future growth, it would recommend increases to PG&E forecasts in these areas. In essence, PG&E is alleging that DRA indulged in cheery picking in that it ignored 2012 increases in 3 of the 4 recorded connection categories, but reflected in its forecasts the one instance where 2012 recorded connections were lower than forecasted.

Most emphatically, DRA did not resort to any type of "cherry picking." In reality, PG&E is being somewhat misleading in its criticism of DRA. As indicated in footnote 42 of PG&E's

[761] Ex. 55 (PG&E-19), p. 9-10, Q/A 45.

[762] Ex. 75 (DRA-7), p. 31, Table 7-7, line 3.

[763] Ex. 55 (PG&E-19), p. 9-13.

Rebuttal (Exhibit 55, page 9-13), PG&E questions DRA's handling of lines 3, 4, and 7 in Table 7-7 (page 31) of Exhibit 75. Looking at that table in more detail reveals that PG&E is being disingenuous. Line 3 of Table 7-7 is calculated by taking a percentage (shown on line 2) of line 1. PG&E does not apparently object to DRA's forecasts for line 1. As shown on line 2, the recorded 2012 percentage used to derive line 3 was actually slightly lower than PG&E had forecasted (34.45% versus PG&E's forecast of 35.00%). If PG&E was being completely honest, it would be criticizing DRA for not carrying forward that lower percentage into 2013 and 2014, which would result in lower line 3 forecasts. As shown on line 2, DRA did not carry forward the slight 2012 decrease, but instead adopted PG&E's forecasts for 2013 and 2014.

PG&E is similarly being disingenuous regarding its criticism of line 4. Line 4 is derived by subtracting line 3 from line 1; that is the methodology that PG&E used, and DRA made the same calculations. Therefore, contrary to PG&E's claims that DRA ignored the higher recorded 2012 data, DRA simply derived its 2013 and 2014 forecasts for line 4 using the same modeling techniques as PG&E.

Lastly, PG&E's criticism of DRA's handling of line 7 is also misplaced. Recorded 2012 non-residential connections were 8,931, as compared to PG&E's 2012 forecast of 8,647, a difference of 284 connections. Put another way, recorded 2012 connections for line 7 were only 3.28% higher than forecasted, which DRA concluded would have no material impact on the 2013 and 2014 forecasts. Contrast that 3.28% difference to the 35.14% difference that occurred in line 5 (PG&E's forecast was 70.00% for 2012, while the recorded percentage was 45.40%, a 35.14% decrease). Clearly, DRA was justified in concluding that the 35.14% decrease needed to be taken into consideration when formulating its forecasts for 2013 and 2014. Similarly, DRA was justified in concluding that PG&E's 2013 and 2014 forecasts for line 7, which DRA found reasonable, would not be impacted by an additional 284 non-residential connections in 2012.

PG&E's remaining Rebuttal issues for MWC 16 have to do with Plug-In Electric Vehicles (PEV) expenditures and Transformer Purchases.[764] For the PEV issue, DRA simply reflected the recommendations of DRA's witness on MWC EV. Differences for Transformer Purchases are solely due to differences in other New Business work categories. Both of these

[764] Ex. 55 (PG&E-19), pp. 9-13 – 9-14.

issues will be automatically revised once the Commission rules on MWC EV expenses and New Business capital expenditures.

4.10 Electric Emergency Recovery

4.10.1 Expense

The Electric Emergency Recovery Program (EER) responds to emergency outages, ranging from routine emergencies that result from equipment failures to major emergencies that arise from severe storms and other disasters.

PG&E forecasts $117.347 million for TY2014 EER expenses.[765] The corresponding DRA estimate for Electric Emergency Recovery expenses is $113.689 million, which is $3.657 million less than PG&E's forecast.[766]

Electric Emergency Recovery expenses are recorded in two Major Work Categories: BH for Corrective Maintenance – Expense with a forecast of $72.608 million and IF for Major Emergencies – Expense with a forecast of $44.739 million.

4.10.1.1 MWC BH – Corrective Maintenance Expense

MWC BH records corrective maintenance expenses associated with routine outages. PG&E forecasts $72.608 million in expenses for MWC BH. PG&E developed its forecast by taking an average of 2009-2011 recorded costs. Additionally, EER is forecasting a 5 percent shift of expenditures from expense to capital due to implementing Mobile Connect.[767] After reviewing PG&E's testimony, workpapers, and discovery responses, DRA agrees with PG&E's TY forecast for MWC BH.

4.10.1.2 MWC IF – Major Emergencies

MWC IF records expenses associated with major emergencies. PG&E forecasts $44.739 million in expenses for MWC IF. The corresponding DRA estimate for major emergencies expenses is $41.081 million.[768]

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[765] Ex. 18 (PG&E-4 workpapers), p. WP 10-1.

[766] Ex. 73 (DRA-5), p. 48.

[767] Ex. 17 (PG&E-4) p. 10-15.

[768] Ex. 73 (DRA-5), p. 50.

PG&E developed its forecast by taking a 5-year average of 2007-2011 recorded costs.[769] According to PG&E, recorded expenses for 2007-2011 have been adjusted to remove authorized recovery costs related to the Catastrophic Event Memorandum Account (CEMA). CEMA allows PG&E to recover costs for government declared state of emergencies and this cost recovery mechanism is separate from the GRC.[770]

In its forecast, PG&E did not adjust the recorded expenses to remove CEMA related-costs associated with Application (A.) 11-09-014. The Settling Parties agreed to a CEMA-related cost recovery of $17.844 million which the Commission has adopted.[771] DRA developed its TY forecast of $41.081 million by removing these CEMA-related costs from the 2007-2011 recorded expenditures. DRA recommends the Commission adopt DRA's forecast because it ensures that there is no double recovery of costs through the CEMA mechanism and the GRC.

4.10.2 Capital Expenditures

For capital expenditures for Major Work Category 17, PG&E requested a total of $352.382 million for the three years, 2012, 2013 and TY 2014.[772] DRA accepted PG&E's three year total amount.[773] Since PG&E underestimated 2012 expenditures, DRA lowered the amount capitalized in 2013 and 2014 to maintain PG&E's requested three year total.

In PG&E's rebuttal testimony, PG&E complains that its requested three year total "lacks foundation", but does not explain what additional work is necessary during the total three-year period. PG&E's testimony is that it wants the three-year total amount revised to include the additional amount spent in 2012.[774]

As PG&E itself say, Routine Emergency costs are variable and unpredictable from year to year.[775] DRA's position is that even though Level 1 emergencies in 2012 were greater than anticipated, Level 1 emergency costs taken as a whole may decrease and level out over a three

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[769] Ex. 17 (PG&E-4), p.10-20.

[770] Ex. 17 (PG&E-4), p.10-20.

[771] D.13-06-007.

[772] Ex. 76 (DRA-8), p. 8.

[773] Ex. 97, p. 8, lines 10-11.

[774] Ex. 55 (PG&E-19), p. 10-4, lines 11-16.

[775] Ex. 55 (PG&E-19), p. 10-4, lines 11-12.

year period, which is why DRA accepted PG&E's 2012-2014 three year total in the first place. An example of how emergency costs can vary by year can be seen in examining recorded costs for MWC 95, Major Emergencies. For 2012, PG&E forecast capital expenditures of $55 million, however actual 2012 capital expenditures for MWC 95 were only $36 million.[776]

DRA continues to recommend the Commission adopt capital expenditures of $137.8 million for 2012, $110.4 million for 2013, and $110.1 million for 2014.[777]

4.10.3 Balancing Account

PG&E is proposing a two-way balancing account for MWC IF to recover costs for major emergencies that do not qualify for cost recovery through the Catastrophic Event Memorandum Account mechanism.[778] DRA recommends that the Commission deny PG&E's request for a two way balancing account to recover non-CEMA related emergency costs. The Commission has a procedure established for PG&E to make its request for recovery of extraordinary incremental costs related to catastrophic events. Establishing another balancing account for recovery of expenses associated with emergencies that do not qualify for CEMA cost recovery is unnecessary and unreasonable because it would offer a "blank check" to PG&E at ratepayers' expense.[779]

4.11 Distribution System Operations

PG&E's Distribution System Operations (DSO) monitors its electric system, manages outage restoration, directs system switching, and manages its electric-related field customer service work.[780]

4.11.1 Expense

PG&E forecasts $54.985 million for its DSO expenses for Test Year 2014.[781] The corresponding DRA estimate for PG&E's DSO expenses is $49.351 million, an adjustment of $5.634 million.[782]

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[776] Ex. 97 (DRA workpapers), p. 9a, table 8-6.

[777] Ex. 76 (DRA-8), p. 8.

[778] Ex. 17 (PG&E-4), p. 10-21

[779] Ex. 73 (DRA-5), p. 51.

[780] Ex. 17 (PG&E-4), p. 11-1.

PG&E says it developed its forecast by using its 2011 recorded expenses as a basis and then adjusting for escalation, additional staff, reduction of system operators and support staff, employee training and software related to electronic wall mapping.[783] PG&E's forecast also includes its proposal to consolidate thirteen existing Distribution Control Centers (DCC) into three new locations.[784]

PG&E records expenses for DSO in four Major Work Categories. They are MWC BA - Electric Distribution Operation Activities, with a forecast of $32.743 million, MWC DD - Field Service and Dispatch Scheduling, with a forecast of $20.328 million, MWC HG - Electric Distribution Operations Technology Activities, with a forecast of $1.037 million, and MWC JV - Maintenance of Information Technology Applications, with a forecast of $0.877 million.[785]

The forecasts in dispute are discussed below.

4.11.1.1 MWC BA – Electric Distribution Operation

PG&E forecasts $32.743 million for MWC BA – Electric Distribution Operation expenses.[786] DRA forecasts $28.769 million for PG&E's MWC BA, or $3.974 million less than PG&E's forecast. The basis for DRA's estimate is PG&E's 2011 recorded costs for this Major Work Category.[787]

PG&E's 2014 forecast of $32.743 million is comparable to historical expense levels.[788] This is problematic. PG&E's recorded adjusted expenses for 2007-2010 include operational costs for 17 DCCs, and its 2011 recorded adjusted expenses includes operational costs for 13 DCCs. PG&E's 2014 GRC forecast is supposed to include costs for the operation of only 3

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[781] Ex. 18 (PG&E-4 workpapers), p. WP-11, Table 11-1.

[782] Ex. 74 (DRA-6), pp. 34-35.

[783] Ex. 17 (PG&E-4), p. 11-9, 11-10, 11-14, and 11-15.

[784] Ex. 17 (PG&E-4), p. 11-2. PG&E plans to construct one central Distribution Control Center and two regional facilities.

[785] Ex. 18 (PG&E-4 workpapers), p. WP 11-1.

[786] Ex. 18 (PG&E-4, workpapers), p. WP 11-1. The costs to operate and maintain PG&E's DCCs are charged to MWC BA. The majority of PG&E employee training costs are planned and recorded in its Provider Cost Centers (PCC). PG&E organized its 2014 GRC filing by MWC and not by PCC. PG&E is requesting employee training costs in MWC BA. (PG&E's response to DRA-PG&E-084-TLG Q.5-i).

[787] Ex. 74 (DRA-6), p. 36.

[788] Ex. 17 (PG&E-4), p. 11-9.

DCCs. It is also supposed to incorporate employee cost reductions and efficiency savings resulting from the DCC consolidation project.

PG&E's 2011 recorded adjusted expenses for MWC BA were shown in PG&E's workpapers as $33.681 million.[789] However, PG&E's 2011 GRC Imputed amount was $36.023 million for MWC BA and its 2011 GRC budgeted amount was $41.242 million.[790] PG&E's 2011 recorded adjusted expense of $33.681 million is thus less than both the imputed amount and the budgeted amount. Similarly, PG&E forecasted $35.536 million for 2012 for MWC BA in its 2014 GRC, but its 2012 recorded adjusted expenses for MWC BA is $33.401 million. Once again, PG&E's forecast exceeds its actual recorded costs.[791]

DRA recommends the Commission use PG&E's 2011 recorded cost of $33.681million for MWC BA, revised for ratepayer savings that should have resulted from staff reductions and reductions in overtime. DRA recommends a total of $28.769 million for the Test Year, though even this amount is likely overstated[792] since PG&E did not provide any documentation that clearly and specifically shows how PG&E incorporated ratepayer savings that should be associated with the DCCs consolidation project into its 2014 GRC Test Year forecast.

PG&E's forecast for 2012 of $35.536 million was supposed to include additional costs of $2.507 million for the addition of seven new positions and "the replacement of 15 Assistant System Operators with 20 higher skilled and more experienced dispatchers."[793] The 2012 forecast was also supposed to include additional costs of $0.750 million for process development associated with its DCCs consolidation project. At the same time, PG&E's 2012 forecast was supposed to show the results of reduced labor and associated overtime. However, PG&E's 2012

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[789] Ex. 18 (PG&E-4 workpapers), p. WP 11-1, Table 11-1.

[790] Ex. 18 (PG&E-4 workpapers), p. WP5-31: PG&E states the following as the reason for the difference between its 2011 Imputed and budgeted amounts: "Increase primarily due to an increased forecast of unclaimed meter costs and routine electric operations labor, partially offset by a reduction in forecasted Distribution Control Center consolidation training costs".

[791] Ex. 74 (DRA-6), p. 37, footnote 83: PG&E's 2011 GRC Imputed amount is from PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018. PG&E's 2012 recorded expense amount is from PG&E's response to DRA-PG&E-108-CKT. The 2011 recorded amount and the 2012 forecasted amounts are from Exhibit (PG&E-4) workpapers, p. WP 11-1.

[792] Ex. 74 (DRA-6), p. 37.

[793] Ex.18 (PG&E-4 workpapers), p. WP 11-8.

forecast was more than PG&E's recorded adjusted expenses of $33.401 million, adding more doubt to the reliability of PG&E's forecasts.[794]

PG&E's 2014 forecast of $32.743 million does not show any identifiable and calculated savings costs for the following: reduced training costs[795] based on reduced headcount, reduced operating costs for 13 eliminated DCCs, reduced maintenance costs (new/upgraded facilities and equipment require less maintenance than older equipment and facilities), calculated efficiency costs gained from eliminating paper wall maps maintained manually and the efficiency gains from implementing electronic wall mapping systems, efficiency savings costs from streamlined operational processes and reduced manual labor, efficiency gains from eliminating the costs and need to maintain, record and manage multiple systems, etc.[796]

PG&E implemented a DCC "pre-consolidation" project with costs of $3.785 million in 2010 and $0.709 million in 2011.[797] PG&E incurred costs for DCC "pre-consolidation" that expanded and upgraded DCCs that PG&E is proposing to eliminate. PG&E did not provide any documentation demonstrating how these costs were incorporated in its Test Year estimate or documentation that discussed how these expanded and upgraded DCCs would be utilized in the Test Year. PG&E's decision to incur costs, at ratepayer expense, to upgrade and expand DCCs that it proposed in its 2011 and 2014 GRCs to eliminate is problematic.

PG&E has embedded historical costs that can be reallocated and utilized for its proposed Test Year activities for MWC BA. It is inappropriate to charge ratepayers excessive costs for PG&E's DCCs consolidation projects for activities that are already included in its historical costs.

As noted above, the Commission has, in the past, expressed concern about projects for which utilities claim "potential benefits" for ratepayers that, somehow, never actually

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[794] Ex. 74 (DRA-6), p. 39.

[795] Ex. 74 (DRA-6), p. 38, footnote 86: PG&E forecasted $0.800 million in 2013 and $0.400 million in 2014 for additional employee training associated with its DCC consolidation project. PG&E received authorized funding in its 2011 GRC for employee training associated with its DCC consolidation project, and therefore PG&E has embedded training costs that can be reallocated and utilized and no additional funding for this activity is required in the Test Year.

[796] Ex. 18 (PG&E-4 workpapers), pp. WP 11-25 to WP 11-31.

[797] Ex. 74 (DRA-6), p. 39, footnote 89 citing PG&E's response to DRA-PG&E-084-TLG Q.5-h.

materialize[798]. Given PG&E's overstated 2011 and 2012 forecasts for MWC BA, this project appears to be one of those. DRA continues to recommend that the Commission adopt a Test Year 2014 estimate of $28.769 million for PG&E's MWC BA. PG&E has not proved that any additional funding is reasonable over this amount.

4.11.1.2 MWC DD – Provide Field Service

PG&E forecasts $20.328 million for its MWC DD – Provide Field Services.[799] DRA used PG&E's 2011 recorded adjusted expenses of $19.813 million for its estimate for this Major Work Category. DRA's estimate is $0.515 million less than PG&E's forecast.

PG&E calculated its forecast for MWC DD using its 2011 recorded adjusted expenses as a basis for its 2012 forecast, and then used its 2012 forecast to calculate its 2014 GRC forecast amount. PG&E says that "for GRC purposes, the forecasted SmartMeter benefits are added back into the forecast because they are being accounted for through the absorption of escalation."[800]

PG&E's recorded adjusted expenses have been relatively stable for the last three years (2010-2012) with a three year average of $19.495 million and a five year average (2007-2011) of $17.592 million. PG&E's testimony for MWC DD does not discuss any proposed programs or projects requiring additional funding over 2011 recorded levels. In fact, PG&E states that its electric customer service work was transferred from its Customer Care Line of Business to its Electric Distribution Operation along with the necessary resources and expenditures to support the transferred work.[801] PG&E's 2011 recorded adjusted expenses of $19.813 million are the highest recorded for the six year period (2007-2012).[802] DRA recommends the Commission adopt $19.813 million as a reasonable expense level for the Test Year.

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[798] See, e.g., D. 06-05-016, mimeo., p. 64.

[799] Ex. 18 (PG&E-4 workpapers), p. WP 11-1.

[800] Ex. 17 (PG&E-4), p. 11-11.

[801] Ex. 17 (PG&E-4), p. 11-11.

[802] Ex. 74 (DRA-6), p. 45.

4.11.1.3 MWC HG – Electric Distribution Operations Technology

In its Application, PG&E forecast $1.037 million for its MWC HG – Electric Distribution Operations Technology Activities.[803] In Rebuttal, PG&E revised that amount to a forecast of $796,000.[804] DRA recommends the Commission adopt PG&E's 2012 recorded adjusted expenses of $0.769 million.[805] The $27,000 that remains in dispute is due to PG&E's addition of escalation. For reasons discussed above, DRA disagrees with the addition of escalation.

4.11.1.4 MWC JV – Maintenance of Information Technology Applications

PG&E forecast $0.877 million for its MWC JV – Maintenance of Information Technology Applications.[806] PG&E's forecast is not justified and should be denied in its entirety.

PG&E's forecast includes software labor (employee and contract labor) costs for the development and testing of its electronic wall mapping system for its DCC consolidation project.[807] PG&E developed its forecast for MWC JV using inputs from PG&E's Concept Estimating tool.[808] PG&E does not show any expenses recorded for MWC JV for 2007-2011.[809]

In PG&E's TY 2011 GRC, PG&E requested additional funding for software implementation costs, among other things, associated with its DCC consolidation project. PG&E then decided to place the DCC consolidation project on hold.[810] PG&E delayed the development of several of the technology projects it proposed in its 2011 GRC because "the technology to

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[803] Ex. 18 (PG&E-4, workpapers), p. WP 11-1.

[804] Ex. 55 (PG&E 19), p. 11-20.

[805] Ex. 74 (DRA-6), p. 45.

[806] Ex. 18 (PG&E-4, workpapers), p. WP 11-1.

[807] Ex. 18 (PG&E-4, workpapers), p. WP 11-29.

[808] Ex. 17 (PG&E-4), p. 11-16.

[809] Ex. 74 (DRA-6), p. 47, footnote 115: PG&E does not show a breakdown of historical expenses or its 2011 GRC imputed amounts for MWC JV. PG&E Imputed $260.9 million for all of its IT work, including Electric Distribution IT for its DCC consolidation project (DRA-PG&E-084-TLG, Q.5-e).

[810] Ex. 74 (DRA-6), p. 47, footnote 116: PG&E states "No specific documentation is available giving formal notification that this project was placed on hold at this time". (DRA-PG&E-084-TLG, Q.5-a).

enable electronic mapping was still evolving…"[811] According to PG&E, it made "financial and operational sense to delay the consolidation until PG&E assessed the best approach to enabling technologies."[812]

DRA considers that it makes "financial and operational sense" for PG&E to prudently reallocate and use the 2011 GRC funding it received (that is still embedded) for its 2014 GRC proposed software labor (employee and contract labor) costs for the development and testing of its electronic wall mapping system.[813]

DRA considers development, implementation and testing costs to be one time non-recurring costs and additional funding is not required each year during the rate case cycle for this activity. PG&E ratepayers should not be required to provide additional funding for recurring costs that are already embedded in historical expenses. PG&E has not provided any documentation to demonstrate that the funding it was authorized in its 2011 GRC associated with its DCC consolidation project is insufficient, so no additional funding is required in the Test Year for PG&E's MWC JV. PG&E had 2012 and has 2013 to develop and test its electronic wall mapping system before the Test Year.

DRA continues to recommend zero ratepayer funding for this project.

4.11.2 Capital Expenditures

4.11.1.1. MWC 78 – Manage Building

MWC 78 is comprised of various subprograms[814]: (1) ATS Tech Center Facility Upgrade; (2) ATS Tech Center Parking Lot; (3) ATS Electric Lab Facility; (4) Weld Lab Upgrade; (5) Normal Operations; (6) San Carlos Service Center; (7) Colma Service Center;

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[811] Ex. 74 (DRA-6), p.47, footnote 117: PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018, p. 1-7.

[812] EX. 17 (PG&E-4), p. 11-15.

[813] Ex. 74 (DRA-6), p. 48, footnote 119: During PG&E's 2011 GRC, DRA toured some of PG&E's DCCs that PG&E proposed to eliminate and while on the tours DRA observed the paper wall maps that PG&E proposed to eliminate. PG&E's 2011 GRC proposal included development and implementation costs for software to implement its electronic wall mapping system which was supposed to streamline operational processes, reduce manual labor, and reduce employee headcount due to gained efficiencies and consolidation. During PG&E's 2014 GRC, DRA once again toured PG&E's DCCs that PG&E proposed to consolidate and also observed a proposed location for one of the new DCCs. During the tour, DRA again observed the paper wall maps being maintained manually.

[814] Ex. 97 (DRA-8 workpapers), p. 42, lines 13-14.

(8) Electric Distribution Building – Mapping; (9) Santa Maria Storm Room; (10) Stockton Service Center Upgrades; (11) Cinnabar Service Center; (12) Meter Reading Upgrades; (13) Auburn Helicopter; (14) Additional Security; and (15) Escalation. 2DRA discusses its labor escalation in Exhibit 72 (DRA-4).[815]

ATS Technical Center Facility Upgrade

PG&E proposes to upgrade its San Ramon Technology Center infrastructure by modernizing the common areas of the facility. The cost estimates cover a wide range of upgrades including corridors, bathrooms, conference rooms, furniture, filing and storage cabinets, lighting, flooring, lobby area, and audio visual equipment.[816] DRA recommends no additional ratepayer funding for this project.

PG&E has approximately 20,000 employees who provide gas and electric service to approximately 15 million people throughout a 70,000 square mile service territory. Every year PG&E performs normal building upgrades throughout its service territory. These costs are normal and continuous and built into PG&E's base costs.[817]

ATS Technical Center Parking Lot

PG&E says the San Ramon Technology Center requires additional parking spaces to accommodate growth in the number of employees, laboratories, work equipment such as vehicles and test trailers, and materials for testing. These costs are routine and continuous and built into PG&E's base rates. Every year PG&E performs normal parking lot upgrades. DRA recommends no additional ratepayer funding for this project.[818]

ATS Electric Lab Facility

PG&E plans to upgrade equipment in the Performance Testing Laboratories to allow continued evaluation of customer-side-of-the-meter technologies, including customer-owned generation, energy storage and demand response methods and technologies and the impact of those technologies on PG&E's system as part of PG&E's integrated laboratory environment.[819]

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[815] DRA's recommendations for Additional Security and Escalation, insofar as they relate to Electric Distribution Support Activities, are addressed in 4.20 of this Opening Brief.

[816] Ex. 17 (PG&E-4), p. 3-11.

[817] Ex. 76 (DRA-8), p. 45.PG&E

[818] Ex. 17 (PG&E-4), p. 3-11.

[819] Ex. 17 (PG&E-4), p. 3-10.

DRA reviewed PG&E's proposed capital expenditures of $200,000 in 2013 and $230 in 2014 and does not dispute them.[820]

Weld Lab Upgrade

PG&E says it is seeking to upgrade its welding lab to improve employee safety and meet changing welding work requirements.

PG&E recorded $27,900 of capital expenditures in 2012, which DRA accepts. DRA has reviewed PG&E's proposed capital expenditures of $100,000 in 2013 and does not dispute it.[821]

Buildings – Normal Operations

PG&E seeks continued capital expenditures to manage Electric Distribution Buildings for 2013 and 2014 of $614,000 based on 2011 recorded spending. DRA has reviewed PG&E's proposed capital expenditures of $2.8 million for 2012, $614,000 for 2013, and $614,000 for 2014.[822]

San Carlos Service Center

PG&E seeks $1.1 million in 2013 to redesign its San Carlos Service Center because it claims to need additional space to accommodate employees during major storms.[823]

As part of this GRC, PG&E is seeking capital expenditures of $82 million for 3 consolidated distribution centers. The purpose of these 3 centers is to provide, among other things, better overview of each service territory, improve working conditions, provide more accurate and up-to-date distribution system information

DRA recommends against providing PG&E additional ratepayer funding for the San Carlos upgrade since this function will be accomplished in the new consolidated distribution centers.

Colma Service Center

PG&E wants $898,242 in 2013 to create a Colma Service Center because it claims to need additional space to accommodate employees during major storms.[824]

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[820] Ex. 76 (DRA-8) p. 46.

[821] Ex. 76 (DRA-8), p. 46.

[822] Ex. 76 (DRA-8), p. 46.

[823] Ex. 21 (PG&E-4), p. WP 20-15.

[824] Ex. 21 (PG&E -4), p. WP 20-15.

DRA recommends against providing any additional ratepayer funding for the Colma Service Center for the reasons described above; this function should be accomplished in the new consolidated distribution centers.[825]

Electric Distribution Building Mapping

PG&E seeks $769, 526 in 2013 to create its Electric Distribution Buildings --- Mapping Building Upgrades.

DRA recommends against providing any additional ratepayer funding for this project for the reasons described above; this function should be accomplished in the new consolidated distribution centers.[826]

San Maria Storm Room

PG&E seeks $738, 296 in 2013 to create its Santa Maria Service Center to accommodate employees during major storms.

DRA recommends against providing any additional ratepayer funding for the this project for the reasons described above; this function should be accomplished in the new consolidated distribution centers.[827]

Stockton Service Center Upgrade

PG&E seeks $535, 288 in 2013 to upgrade its Stockton Service Center because of overcrowding caused by gas and electric employees sharing the same space.

As part of this GRC, PG&E is seeking capital expenditures of $82 million for 3 consolidated distribution centers. At the time of the completion of the consolidated distribution centers, 130 positions that occupy space in the current local distribution centers will be reduced to 100 positions and these positions will be moved to the new centers. DRA recommends no ratepayer funding for this project until the vacated space can be taken into consideration.

Cinnabar Service Center

PG&E seeks $234,016 in 2013 to upgrade its Cinnabar Service Center to build individual offices for four supervisors.[828]

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[825] Ex. 76 (DRA-8), p. 47.

[826] Ex. 76 (DRA-8), p. 47.

[827] Ex. 76 (DRA-8), p. 47.

As noted above, as part of this GRC, PG&E is seeking capital expenditures of $82 million for 3 consolidated distribution centers. At the time of the completion of the consolidated distribution centers, 130 positions that occupy space in the current local distribution centers will be reduced to 100 positions and these positions will be moved to the new centers. DRA recommends no ratepayer funding for this project until the vacated space can be taken into consideration.

Electric Distribution Buildings – Meter Reading Upgrades

PG&E wants $196,603 in 2013 to upgrade its electric distribution buildings meter reading space in San Francisco.

As noted above, as part of this GRC, PG&E is seeking capital expenditures of $82 million for 3 consolidated distribution centers. At the time of the completion of the consolidated distribution centers, 130 positions that occupy space in the current local distribution centers will be reduced to 100 positions and these positions will be moved to the new centers. DRA recommends no ratepayer funding for this project until the vacated space can be taken into consideration.

Electric Distribution Buildings – Auburn Helicopter

PG&E seeks $175,357 in 2013 to perform an electric distribution buildings – Auburn Helicopter Hangar conversion.

DRA recommends no additional ratepayer funding for this project until the space vacated as part of the distribution center consolidation is taken into consideration.

4.12 Electric Distribution Capacity

PG&E's forecast for Electric Distribution Capacity includes MWC 06 and MWC 46.

4.12.1 MWC 06 – Distribution Line Capacity

MWC 06 reflects capital expenditures for expansion work that takes place outside of substations, and includes projects to correct capacity and overload problems on PG&E's distribution system.

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[828] Ex. 21 (PG&E-4), p. WP 20-15.

DRA recommends that recorded 2012 capital expenditures of $89.408 million be used (versus PG&E's forecast of $83.057 million). For 2013 and 2014, DRA is recommending capital expenditures of $84.185 million and $102.094 million, respectively, while PG&E has forecasted expenditures of $85.148 million and $107.913 million.[829] DRA is recommending two adjustments to MWC 06: a reduced forecast for Overhead Transformer replacements and a reduction in the number of Mainline Loop projects.

For the area of Overhead Transformer replacements, DRA's investigation showed that PG&E has failed to justify its proposed transformer replacements for 2013 and 2014. For 2012, PG&E's forecast of 176 transformer replacements represents a decrease of 83 replacements over the prior year. Clearly, PG&E has given low priority to this matter. If there was some necessity to accelerate transformer replacements, PG&E would have begun doing so in 2012, rather than decreasing the replacements. In DRA's judgment, replacing 300 transformers in both 2013 and 2014 is a more reasonable estimate. DRA's 2013 and 2014 forecasts represent an increase of 124 over the forecasted 2012 level, and are over 15% greater than the recorded 2011 level of 259.

For the Mainline Loop projects, PG&E fails to explain why a sudden increase in these projects is necessary. In its workpapers, PG&E shows that it wants to complete 115 mainline loop projects over the six-year period 2011 through 2016.[830] In the first three years of the completion period (2011 through 2013), PG&E is undertaking 16 mainline loop projects. DRA has examined the capital expenditures for that period and has concluded that PG&E's 2012 and 2013 forecasts are reasonable. The remaining 99 projects are being forecasted for the last three years of the completion period (2014 through 2016). DRA understands why PG&E wants to undertake these projects. However, no justification has been provided to explain why the number of mainline loop projects proposed for this rate case is over six times greater than the previous three-year period. It is also important to note that no projects of this type were done prior to 2011.[831] That fact, coupled with the fact that PG&E is only proposing to undertake 16 mainline loop projects over the period 2011 through 2013, indicates that there is no urgency

[829] Ex 75, (DRA-7), p. 38, Table 7-8, line 10.

[830] Ex. 20 (PG&E-4), Table 12-12, pp. WP 12-37 through WP 12-41.

[831] Ex. 75 (DRA-7), p. 38, Table 7-8, line 6.

to complete all 115 projects by 2016. DRA is recommending that 32 mainline loop projects be undertaken in this second three-year period (2014 through 2016), which is twice as many as were completed in the 2011 through 2013 period. DRA is recommending that the 32 projects be equally divided over the three-year rate case cycle (2014 through 2016).

In Rebuttal, PG&E states it has identified 11,175 distribution transformers that are loaded to greater than 100%, and states that it believes this justifies the forecasted increase in the number of overloaded transformers.[832]

DRA acknowledges that large number of transformers can exceed their rated capacities under certain circumstances. However, in its workpapers, PG&E shows that it replaced 259 transformers in 2011, and proposed replacing 176 in 2012, a decrease of 83 replacements from the previous year. PG&E cannot suddenly claim in 2013 that there is an urgent need to increase transformer replacements when, in 2012, it replaced fewer transformers than in 2011. By its actions in 2011 and 2012, PG&E has given clear indications that it does not consider transformer replacements a high priority. If PG&E is now claiming otherwise, that would suggest that it was putting profits ahead of reliability and safety when it proposed decreasing its transformer replacement rate in 2012. PG&E has provided no justification to support its request to suddenly increase transformer replacements in 2013 and 2014 – 375 replacements in 2013 and 417 in 2014. DRA's 2013 and 2014 forecasts represent an increase of 124 over PG&E's forecasted 2012 level, and are over 15% greater than the recorded 2011 level of 259. DRA's proposed transformer replacement of 300 in each of the years 2013 and 2014 is completely reasonable.

In Rebuttal, PG&E also challenges DRA's recommendations regarding Mainline Loop projects.[833] PG&E alleges that all 99 mainline loop projects need to be completed in the 3-year period 2014 through 2016 in order to provide better reliability and operational flexibility.

DRA would again like to point out that during the 2011 through 2013 period, PG&E undertook 16 mainline loop projects. For the 2014 through 2016 period, DRA is proposing that 32 mainline loop projects be undertaken, twice as many as the previous 3-year period. If reliability was not adversely impacted by doing 16 projects during the first 3-year period, DRA

[832] Ex. 55 (PG&E-19), p. 12-4, Q/A 18.

[833] Ex. 55 (PG&E-19), p. 12-7, Q/A. 24.

does not see why it would be negatively impacted by doing 32 projects during the second 3-year period. If PG&E is now claiming that DRA's recommendation would negatively impact reliability, that would suggest that PG&E was putting profits ahead of reliability when it previously undertook only 16 mainline loop projects. It should also be noted that prior to 2011, no mainline loop projects had been conducted by PG&E.[834]

4.12.2 MWC 46 – Distribution Substation Capacity

MWC 46 is the other MWC that relates to electric distribution capacity. Whereas MWC 06 (see previous section) reflects capital expenditures for capacity expansion work that takes place outside of substations, MWC 46 examines capacity work within substations.

DRA is recommending that recorded 2012 capital expenditures of $51.507 million be used (versus PG&E's forecast of $58.330 million). For 2013 and 2014, DRA is recommending capital expenditures of $52.610 million and $73.858 million, respectively, while PG&E has forecasted expenditures of $52.616 million and $74.892 million.[835].

During the capital review process of a GRC, DRA seeks to determine whether the requesting utility has adequately justified the need for each of its proposed capital projects. DRA then seeks to determine that the estimated cost of each project is reasonable. For substation projects, utilities have an additional regulatory requirement that must be met. General Order (GO) 131-D states, in part, the following in Section III.B:

> No electric public utility shall begin construction in this state of any electric power line facilities or substations which are designed for immediate or eventual operation at any voltage between 50 kV or 200 kV or new or upgraded substations with high side voltage exceeding 50 kV without this Commission's having first authorized the construction of said facilities by issuance of a permit to construct in accordance with the provisions of Sections IX.B, X, and XI.B of this General Order. (Emphasis added.)

As part of its regulatory burden, for each Substation project with high side voltage exceeding 50 kV, PG&E must either obtain a Permit To Construct (PTC) or a Certificate of Public Convenience and Necessity (CPCN) from the Commission, or it must determine that the

[834] Ex. 75 (DRA-7), p. 38, Table 7-8, line 6.

[835] Ex. 75 (DRA-7), p. 42, Table 7-9, line 4.

project falls under one of the exempt categories, which excludes the project from compliance with the PTC portions of the Order.

To investigate this matter further, DRA issued Data Request DRA-160-GAW. The thrust of this data request was to obtain an explanation of what authority PG&E was operating under in order to proceed with these MWC 46 capital projects. In its response, PG&E stated that it would be seeking a PTC for its proposal to construct the Gosford Substation project, but had not yet done so. PG&E further stated that the final permitting would be determined at a later date when the project was more thoroughly defined.

In DRA's experience, PTCs are often lengthy proceedings that can take years to resolve. The Gosford Substation project has apparently not yet been sufficiently defined to begin the PTC process. PG&E has forecasted spending $1.000 million for this project in 2014.[836] In DRA's judgment, it is likely that this project will not begin until after 2014. At this stage, it is not even known whether or not the PTC will be approved.

In Rebuttal, PG&E states that the $1.0 million it proposes to spend in 2014 for the Gosford Substation project does not include any costs for the construction of the substation, but instead will be used to perform necessary groundwork for construction.[837] In response to this allegation, DRA would like to point out that page WP 12-134 of PG&E's workpapers (Exhibit 20) appears to show a different story. That page shows that $250,000 is being spent in 2012, nothing is spent in 2013, and $1 million is being spent in 2014. The $250,000 being spent in 2012 would presumably be used for the "necessary groundwork" prior to the actual construction. In addition, if the Gosford project has not progressed to the point of knowing how the permitting process will proceed, in spite of having spent $250,000 in 2012 on background work, then DRA's judgment is that it is unlikely that anything will be spent in 2014.

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[836] The Gosford Substation is a multi-year project that is not scheduled to be completed until 6/1/16. Workpaper Table 12-8 (page WP 12-19) shows on line 39 that $1.000 million is scheduled to be spent in 2014, with additional expenditures in 2015 and 2016. DRA is not currently recommending that the project be cancelled, only that the 2014 expenditures be pushed back an additional year.

[837] Ex. 55 (PG&E-15), p. 12-4, Q/A 11.

4.13 Substation Asset Strategy

4.13.1 Expense

Substation Asset Strategy refers to the maintenance of PG&E's 770 distribution substations, consisting of transformers, voltage regulation equipment, protective devices, automation equipment, and bus structure equipment.[838]

PG&E forecasts $40.064 million for Substation Asset Strategy expenses for TY2014, which is an increase of $6.988 million or 21% over 2011 expenses of $33.077 million.[839] The corresponding DRA estimate is $35.452 million, which is $4.612 million less than PG&E's forecast of $40.064 million, and $2.375 million higher than 2011 recorded expenses.

PG&E's forecast includes expenses for corrective maintenance, preventive maintenance, and substation support activities.

4.13.1.1 MWC GC – Distribution Substation Maintain & Operate

PG&E records expenses for Substation Asset Strategy in Major Work Category (MWC) GC.

4.13.1.2 Corrective Maintenance

Corrective Maintenance includes the repair of failed equipment.[840] PG&E forecasts $14.142 million in expenses for corrective maintenance, which is an increase of $3.521 million or 33.15% over 2011 expense levels.[841] The corresponding DRA estimate for corrective maintenance expenses is $10.372 million.

PG&E says it developed its forecast by multiplying the forecasted number of notifications by the forecasted cost per notification.[842] During discovery, DRA identified errors with PG&E's cost per notification for 2011, on which PG&E's TY2014 forecast is based. PG&E said that the discrepancy was due to an error in the spreadsheet used in the forecast and provided as a workpaper. "That spreadsheet did not have the most up-to-date information for the

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[838] Ex. 17 (PG&E-4), p. 13-1.

[839] Ex. 21 (PG&E-4), p. WP 13-1.

[840] Ex. 17 (PG&E-4), p. 13-6.

[841] Ex. 17 (PG&E-4), p. 13-1.

[842] Ex. 21 (PG&E-4), p. WP 13-7.

number of corrective notifications recorded in 2011. The correct total number of maintenance notifications recorded in 2011 is 2,571, not 2,265, and the correct unit cost is $4.131 thousand."[843] PG&E will correct this in the upcoming errata filing."

Using the corrected information, DRA noted that the cost per notification for corrective maintenance declined notably from $4,131 in 2011 to $3,446 in 2012. In order to take into account fluctuations in cost-per-notification throughout the years, DRA developed its forecast using a four-year average of recorded unit costs (2009-2012).[844] DRA agrees with PG&E's forecasted increase in number of notifications. DRA developed its forecast of $10.372 by multiplying the four-year average of recorded unit costs by PG&E's forecasted number of notifications.

DRA's forecast of $10.372 million for corrective maintenance expenses was developed using historical unit costs, and also takes into account PG&E's expected increase in corrective maintenance notifications. DRA recommends the Commission adopt it.

4.13.1.3 Preventive Maintenance

Preventive Maintenance includes inspections, switching and restoring service to customers, calibration and adjustment, and other routine maintenance work performed on PG&E's substations. PG&E forecasts $16.505 million in TY expenses for preventive maintenance. PG&E developed its forecast by multiplying the number of planned units in 2012 times a 2-year average of cost.[845] After reviewing PG&E's testimony, workpapers, and discovery responses, DRA agrees with PG&E's request of expenses for preventive maintenance.

4.13.1.4 Substation Support Activities

Substation Support Activities include all other projects or staff that support PG&E's substation system including SAS engineering staff, system funded projects, miscellaneous materials and contracts, and vegetation management.[846]

PG&E is forecasting $8.550 million in TY expense for substation support activities. The corresponding DRA estimate is $7.697 million. Ex. 73 (DRA-5), p. 55.

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[843] Ex. 73 (DRA-5), p. 53.

[844] Ex. 73 (DRA-5), p. 54 footnote 140: See Table 5-28. Unit cost prior to 2009 was not provided.

[845] Ex. 17 (PG&E-4), p. 13-6.

[846] Ex. 21 (PG&E-4), p. WP 13-7.

PG&E forecasted most TY expenses for substation support activities using a 3-year average (2009-2011) of recorded adjusted costs for each activity.[847]

PG&E forecasts $2.500 million for System Funded Projects, one of PG&E's substation support activities. System Funded Projects include lease payments, facility costs, license fees, various studies, transformer relocation costs, and other work.[848] PG&E developed its TY forecast for System Funded Projects by taking a 3-year average (2009-2011) of recorded costs and adding $0.900 million for incremental costs over 2011 recorded expenses. PG&E's forecast of $2.500 million for system funded projects is 89.97% over 2011 recorded costs of $1.316 million.

PG&E forecasts an incremental increase of $0.500 million for the relocation of two transformers ($0.250 million per transformer) as part of TY expenses for System Funded Projects. PG&E currently has approximately 18 transformers in storage and plans to relocate two transformers per year starting in 2012.[849] DRA asked PG&E to explain why PG&E needs additional funding for transformer relocations starting in 2012 and continuing into the TY and why it waited until now to relocate transformers.[850]

PG&E's responded:

> PG&E believes it is not economical to maintain a large inventory of surplus transformers in storage. The condition of a used transformer may deteriorate over time if not in-service, due to factors such as the settling of oil. The level of surplus transformers has increased as transformers are replaced in order to increase capacity. PG&E anticipates relocating surplus transformers on an annual basis as a part of regular business practice.[851]

Historically, PG&E has not conducted transformer relocations at the rate being proposed in this GRC. PG&E only relocated one transformer in the 2009-2011 period, a process, which PG&E claims, is not even complete. When DRA asked PG&E for information about this relocation, PG&E stated: "The total cost, including 2013 year-to-date, is $85,592. The

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[847] Ex. 21 (PG&E-4), p. WP 13-7.

[848] Ex. 73 (DRA-5), p. 55 citing DRA-EJ1-191 question 5.

[849] Ex. 73 (DRA-5), p. 55 citing DRA-EJ1-016 question 10.

[850] Ex. 73 (DRA-5), p. 56 citing DRA-EJ1-191 question 7c.

[851] Ex. 73 (DRA-5), p. 56.

reassembly, refilling of oil and dress and testing of the transformer have not yet been performed. This relocation is not representative of transformer relocation costs because the "relocation" is not yet complete. Aside from the aforementioned costs, there were no other costs recorded or reallocated."[852]

Transformer relocations are apparently low priority work for PG&E and PG&E did not provide sufficient supporting documentation or cost benefit analyses to substantiate its request. DRA opposes additional funding for transformer relocations.

DRA asked PG&E to identify and explain all other incremental funding forecasted in TY expenses for System Funded Projects.[853] PG&E said that, in addition to the transformer relocations, PG&E included $400,000 in the forecast to support programmatic substation reliability improvement activities. The amount was based on PG&E's "engineering judgment" and there were "no specific calculations" associated with the value.

PG&E's request for system funded projects is excessive and the Commission should deny it. Instead, DRA recommends the Commission adopt a TY estimate of $1.647 million for System Funded Projects. This forecast is based on a 3-year average (2009-2011) of recorded expenses expressed in 2011 dollars.[854]

4.13.2 Capital Expenditures

4.13.2.1 MWC 48 – Substation Replacement

MWC 48 addresses PG&E's request to replace substation equipment (other than transformers, which are discussed in MWC 54). DRA is recommending that recorded 2012 capital expenditures of $40.319 million be used (versus PG&E's forecast of $50.401 million). For 2013 and 2014, DRA is recommending capital expenditures of $54.892 million and $56.393 million, respectively, while PG&E has forecasted expenditures of $54.906 million and $66.021 million.

The only adjustment proposed by DRA for MWC 48 is for switchgear projects. In the 2011 GRC, PG&E sought to undertake 14 switchgear replacement projects over the period 2009

[852] Ex. 73 (DRA-5), p. 56 citing DRA-EJ1-191 question 7b.

[853] Ex. 73 (DRA-5), p. 57 citing DRA-EJ1-016 question 10b.

[854] 2009 recorded expenses = $1,847; 2010 recorded expenses = $1,777, 2011 recorded expenses = $1,316. The 3-year average is $1,647. Recorded expenses in 2011 dollars from DRA-255-EJ1 question 1.

through 2013. In the current 2014 GRC, PG&E states in its testimony that only two of the switchgear projects proposed during the last GRC were actually completed. Indeed, a close inspection of the projects proposed (and authorized) in the 2011 GRC shows that 11 of the replacement projects are being requested again in the current GRC. In its testimony, PG&E states that it decided to reschedule the original 2011 switchgear projects so that it could apply lessons learned from the two projects that it did complete. More specifically, PG&E states that rather than pursuing multiple switchgear projects simultaneously as originally planned in the 2011 GRC, it decided to wait to complete and learn from the Mission Substation project, and then leverage lessons learned from that project to the other switchgear projects.[855]

In this current GRC, PG&E is proposing to work on 10 switchgear projects simultaneously in 2013. Since PG&E was only able to complete two switchgear projects during the last GRC cycle, undertaking 10 projects in one year may be ambitious. DRA assumes that PG&E has gained experience from working on the Mission Substation project, and is now better equipped to work on multiple replacement projects. Therefore, even though PG&E's 2013 request of $33.588 million is larger than any previous recorded year since at least 2007, DRA is accepting PG&E's forecast.

For 2014, PG&E is proposing to work on 13 switchgear projects simultaneously. This request is ambitious. PG&E's 2014 forecast of $42.962 million is more than 50% higher than the previous largest recorded expenditure ($28.125 million in 2011). In DRA's judgment, a more reasonable forecast for 2014 is the $33.588 million forecast proposed by PG&E (and accepted by DRA) for 2013. As previously mentioned, the use of the $33.588 million forecast will provide PG&E with a higher level of expenditures than any previously recorded year since at least 2007. It will also enable PG&E to work on multiple projects simultaneously, allowing for the replacement of the most unreliable switchgears.

In Rebuttal, PG&E alleges that it is important to maintain a balance of projects in various phases of the project cycle (between engineering and construction), something that DRA's proposal apparently does not do.[856]

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[855] Ex. 17 (PG&E-4), p. 13-9, lines 26-28.

[856] Ex. 55 (PG&E-19), p. 13-10 Q/A. 37.

In response to PG&E's allegations, DRA would like to point out that DRA actually made no determination as to how the projects should be allocated between engineering and construction. When DRA determined that PG&E was only able to undertake 2 of 14 switchgear projects in 2011, DRA became concerned about PG&E's ability to handle all 13 of its proposed projects in 2014. In DRA's judgment, juggling 10 projects in a given year, as PG&E proposes to do for 2013, is a more reasonable workload. DRA's recommendation for 2014 is simply to maintain the same level of work (and the same cost) as 2013.

If PG&E believes that it is important to maintain a more even balance between engineering and construction, DRA would not object to PG&E substituting an additional engineering switchgear project in place of a construction project. It should also be noted that PG&E apparently had no qualms about the engineering/construction ratio of its 2013 forecast; DRA does not understand why PG&E would object to using the same forecast (and the same engineering/construction ratio) for 2014.

4.13.2.2 MWC 54 – Replacement of Transformers

In MWC 54, PG&E identifies, prioritizes, and replaces transformers (within substations) that have the highest risk of failing. This program also maintains an adequate supply of mobile and emergency transformers.[857]

DRA is recommending that recorded 2012 capital expenditures of $52.462 million be used (versus PG&E's forecast of $62.329 million). For 2013 and 2014, DRA is recommending capital expenditures of $41.143 million and $55.051 million, respectively, while PG&E has forecasted expenditures of $41.151 million and $64.854 million.[858]

DRA has only proposed one adjustment to MWC 54. In its testimony, PG&E states that its 2014 forecast for Transformer Replacements is based on replacing 11 transformers. PG&E states that the number of targeted transformer replacements is consistent with historical trends.[859] In its workpapers, PG&E shows a chart of historical transformer replacements for the period 2007 through 2011.[860] That table shows that the yearly replacement rate varies between 6 and

[857] Ex. 17 (PG&E-4), p. 13-14, lines 2 through 6.

[858] Ex. 75 (DRA-7), p. 45, Table 7-11, line 7.

[859] Ex. 17 (PG&E-4), p. 13-14, lines 17 through 21.

[860] Ex. 21 (PG&E-4), p. WP 13-15, Table 13-13.

14, with an historical average of less than 10. When the table is expanded to include PG&E's forecasts for 2012 and 2013, the average drops to just above 9. Because of the variability in the number of replacements, DRA is recommending that the average of 9 replacements be used in 2014. DRA therefore reduced PG&E's 2014 forecast of 11 replacements by two.

In its Rebuttal testimony for MWC 54. PG&E states that it actually replaced 12 transformers in 2012, apparently suggesting that DRA should have incorporated that recorded 2012 amount into its calculation.[861]

As discussed in DRA's testimony[862], recorded replacements varied considerably, ranging from a low of 6 in 2009 to a high of 14 in 2010. Because of this variability, no meaningful type of trend could be determined. Instead, DRA looked at the 5-year average (2007 through 2011 recorded) of these replacements, and found that the simple average was 9.6. When DRA added PG&E's proposed replacements for 2012 and 2013, the average became 9.3. PG&E is now reporting for the first time that it actually replaced 12 transformers in 2012, four more than its forecast of eight. What PG&E is not reporting is how that increase in 2012 impacts its forecast for 2013. Does the increase in 2012 mean that labor and plant resources have been depleted, resulting in fewer replacements in 2013?

Regardless of which replacement numbers are used, the fact remains that historically, transformer replacements have varied greatly from year to year. PG&E has not justified a replacement rate of 11. A simple average of transformer replacements provides the best means for forecasting a replacement rate for 2014. In DRA's judgment, the most reasonable average includes the five years of recorded replacements (2007 through 2011) along with PG&E's original forecasts for 2012 and 2013. The result of that average is 9.3 transformer replacements, which DRA has used as its forecast for 2014.

4.13.2.3 MWC 58 –Distribution Substation Safety

MWC 58 is comprised of four subprograms (1) Seismic; (2) Fire Protection Suppression; (3) Security; and (4) Safety.[863] For Major Work Category 58, PG&E forecasts capital

[861] Ex. 55 (PG&E-19), p. 13-13, Q/A. 48.

[862] Ex. 75 (DRA-7), p. 49.

[863] Ex. 17 (PG&E-4), p. 13-16.

expenditures in 2014 of $3.126 million. DRA's forecast is $16,500 for 2012, $97,000 for 2013 and $97,000 for 2014.[864]

DRA does not oppose PG&E's forecast for 2013 and 2014 for Safety costs.[865] DRA disagrees with PG&E's forecasts for three Distribution Substation Safety cost sections: 1) Seismic; 2) Fire Protection/Suppression; and, 3) Security.

During PG&E's last GRC, PG&E received authorization to recover $5.7 million from ratepayers in 2011 for Distribution Substation Safety costs, while PG&E only spent $1.2 million in 2011.[866] PG&E decreased its expenditures for Distribution Substation Safety costs in 2012 to only $142,900. PG&E stated that it underspent funds in this category because funds were allocated to higher priority projects.[867]

Seismic costs

In 1996, ALX Engineering completed a "Technical Survey of Unreinforced Masonry Substation Building" for PG&E that evaluated PG&E's distribution substation seismic conditions. The majority of projects remedied prior to 2007 were assessed to be in either poor or very poor condition. In this GRC, PG&E desires to remedy distribution substation facilities that were assessed to be in good and fair condition in years 2014-2016.[868]

While no additional testing of the buildings have been performed since 1996,[869] PG&E believes that the Technical (engineering) Survey should be updated. PG&E has not submitted any evidence that any of the facilities that were assessed to be in good and fair condition should be retrofitted in this GRC. DRA based its estimate on a three year average of 2009-2011 seismic costs.

Fire Protection and Suppression

PG&E based its forecast for Fire Protection and Suppression costs for years 2013 and 2014 based on the 2007 and 2008 totals. During 2009-2012, fire protection and suppression

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[864] Ex. 76 (DRA-8), p. 16.

[865] Ex. 97 (DRA workpapers), pp. 12-16a.

[866] Ex. 97 (DRA workpapers), p. 13, lines 3-5.

[867] Ex. 55 (PG&E-17), p 13-14, lines 10-15

[868] Ex. 97 (DRA workpapers), p. 13, lines 16-21.

[869] 18 RT 2030, line 15, Yeung/PG&E.

projects were limited to a few substations and are mainly carryover projects to complete work that began in prior years. During these years, fire protection and suppression work was incorporated in other MWCs, such as the Oakland X Bank 4 bank replacement under MWC 54, which included an upgrade to the fire suppression system to accommodate the increase in transformer size and gallons of oil. PG&E identified two potential fire protection suppression projects for 2013 (Larkin and Embarcadero substation) but has not identified any 2014-2016 fire protection and suppression projects.

While PG&E has included its fire protection and suppression work in other MWCs during the last four years, it is requesting additional funding for fire protection and suppression work in MWC 58 in this GRC. In addition, PG&E could not identify specific substation fire protection and suppression projects planned during the 2014-2016 timeframe. Without specific plans, PG&E is unprepared in this rate case to support is request, and has no supportable documents to evaluate. Finally, it is difficult to determine if all fire protection and suppression costs included in other MWC s that were used during the last four year by PG&E were adjusted to remove these costs.

During the last four years, PG&E's fire protection and suppression work recorded in MWC 58 have decreased every year.[870] Consistent with PG&E's current booking practices for fire protection and suppression work, DRA used a three year average (2009-2011) to calculate PG&E's fire protection and suppression costs for 2013 and 2014.

Security

PG&E is requesting $400,000 a year in security costs based on one completed project. DRA recommends capital expenditures of $16,500 for 2012, $97,000 for 2013, and $97,000 for 2014.[871]

PG&E did not identify any firm security projects that are planned during 2013 and 2014.[872] DRA asked PG&E to provide it with information related to specific Substation Security

[870] Ex. 76 (DRA-8), p. 15.

[871] Ex. 76 (DRA-8), p. 16.

[872] 18 TR 2034, lines 4-7, Yeung/ PG&E.

Projections or MWC 58. However, PG&E failed to identify any specific Substation Security projects planned or their respective dollar amounts during the 2012-2016 timeline.[873]

During the last three years (2009-2011, PG&E's security costs included in MWC 58 have decreased every year. Therefore, DRA recommends the use of a three year average (2009-2011) for PG&E's security costs for 2013 and 2014 as this is the only reliable data and dollar available, Therefore, DRA recommends capital expenditures of $16,500 for 2012, $97,000 for 2013, and $97,000 for 2014.[874]

4.13.2.4 MWC 59 – Distribution Substation Emergency Equipment Replacement

For capital expenditures in MWC 59, PG&E requested $107,342 million for the three years, 2012, 2013 and 2014.[875] DRA accepted PG&E's three year total amount. Since PG&E underestimated 2012 expenditures, DRA lowered the amount capitalized in 2013 and 2014 to maintain PG&E's requested three year total. In PG&E's rebuttal testimony, PG&E complains that DRA's three year total is "arbitrary and underfunds emergency substation work,"[876] but does not explain what additional work is necessary during the total three-year period. PG&E wants to revise its three-year total amount to include the additional amount spent in 2012.[877]

In PG&E's rebuttal testimony, PG&E admits that it does not know when an emergency will occur and what the extent of the resulting damages will be.[878] DRA's position is that even though Substation Emergency Equipment in 2012 were greater than anticipated, Substation Emergency Equipment costs taken as a whole may decrease and level out over a three year period, which is why DRA accepted PG&E's 2012-2014 three year total for this MWC. An example of how emergency costs can vary by year can be seen when you examine MWC 95,

[873] Ex. 76 (DRA-8), p.16.

[874] Ex. 76 (DRA-8), p. 16.

[875] Ex. 76 (DRA-8), p. 11.

[876] Ex. 55 (PG&E-19), p. 13-20.

[877] Ex. 55, (PG&E-4) p. 13-20 and 13-21, lines 20-2

[878] Ex. 55 (PG&E-4), p. 13-20, lines 22-24

Major Emergencies. For 2012, PG&E forecast capital expenditures of $55 million; however, actual 2012 capital expenditures for MWC 95 were only $36 million.[879]

4.14 Electric Engineering – Distribution Planning, Operations and Power Quality

PG&E's Electric Engineering program consists primarily of electric distribution engineers who support a variety of asset management and operating activities.

PG&E forecasts $24.147 million for Electric Engineering – Distribution Planning, Operations, and Power Quality expenses for TY2014, which is an increase of $4.544 million or 23% over 2011 expenses of $19.603 million.[880] The corresponding DRA estimate for Electric Engineering expenses is $21.427 million, which is $2.720 million less than PG&E's forecast of $24.147 million, and $1.824 million over 2011 recorded expenses.[881]

4.14.1 MWC FZ – Electric Engineering

PG&E records expenses for Electric Engineering in MWC FZ under Maintenance Activity Type (MAT) codes FZA, FZB, FZC, FZD, and FZE. PG&E's forecast of $23.722 million[882] for the Electric Engineering Program was developed using 2011 actual expenditures and making upward adjustments for incremental expected future program costs.[883]

DRA's TY estimate of $21.427 million uses 2011 actual expenditures and adjusts PG&E's expected future program costs for each Maintenance Activity Type.[884]

4.14.1.1 MAT FZA: Distribution Engineering - Distribution Planning Operation and Power Quality

FZA records the expense-related costs of the Electric Distribution Engineers who work on electric distribution system planning and operations, as well as costs related to training and any special technical studies.[885] PG&E's TY estimate for MAT FZA expenses is

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[879] Ex. 97 (DRA workpapers), p. 9a, table 8-6. See, e.g., MWC 95 discussed in Section 4.10.2, above.

[880] Ex. 18 (PG&E-4 workpapers), p. WP 14-1.

[881] DRA totaled its forecasted 2014 expenses for MAT FZA, FZB, FZC, FZD, and FZE and then escalated. DRA did not escalate its forecasts for individual MATs

[882] Ex 55 (PG&E-19), p. 14-2.

[883] Ex 17 (PG&E-4), p. 14-5.

[884] Ex. 73 (DRA-5), p. 59.

[885] Ex. 73 (DRA-5), p. 59 citing DRA-025-EJ1 question 1.

$18.793 million. The corresponding DRA estimate is $18.093 million. DRA does not object to PG&E's requested funding for 2 additional entry engineers, the realignment of 3 Power Quality Engineers and 1 Supervisor to MWC FZA, and an increase in operations related activities.

PG&E also requested an additional $700,000 over 2011 recorded costs to fund an increase in operations related activities.[886] DRA asked PG&E to provide a more detailed breakdown of the activities and associated costs. In the course of discover, DRA learned that PG&E's additional $700,000 request is for "other activities PG&E is likely to pursue."[887]

DRA opposes additional funding for "other initiatives PG&E is likely to pursue." Ratepayer funding should not be forecast for unidentified initiatives with no breakdown of costs or analyses. PG&E has embedded costs from ongoing or completed initiatives that it can reallocate if necessary. DRA's forecast more realistically reflects PG&E's relatively flat spending history in MAT FZA, and DRA recommends the Commission adopt it.

4.14.1.2 MAT FZB: Voltage Problem and Electro-Magnet Field (EMF)

MAT FZB records the expense-related costs associated with field personal that trouble-shoot and investigate customer voltage complaints, SmartMeter voltage investigations.[888]

PG&E's TY estimate for MAT FZB expenses is $1.800 million. The corresponding DRA estimate for MAT FZB expenses is $1.221 million.[889]

PG&E is requesting additional funds for "recording volt meter installation and removals cost realignment" and "smart meter high/low voltage investigations." DRA asked PG&E to reference where in workpapers it had removed costs for "realignment," but PG&E said there was no specific place it could reference.[890]

DRA opposes PG&E's request for $375,000 in additional funding for the realignment because PG&E cannot identify the removal of costs for recording of volt meter installations from MWC BH where it was previously charged. PG&E's response indicates that the historical

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[886] Ex. 18 (PG&E-4), p. WP 14-13.

[887] Ex. 73 (DRA-5), p. 61 citing DRA-025-EJ1 question 6. In the course of responding to DRA data requests, PG&E found an error later corrected in Errata. (Ex. 55, p. 14-3).

[888] Ex. 73 (DRA-5), p. 63 citing DRA-025-EJ1 question 7.

[889] Ex. 73 (DRA-5), p. 63.

[890] DRA-025-EJ1 question 9.

expenses for this activity are still embedded within MWC BH and were not adjusted out. In order to prevent the duplication of costs, DRA rejects realignments that even PG&E cannot be track.[891]

DRA conducted discovery to assess the progress of voltage investigations conducted because of increasing SmartMeter data. PG&E states, "due to the implementation of SmartMeters, more data regarding customer service voltage is available and allows for greater detail of high or low voltage situations that previously may have gone undetected."[892] PG&E forecasted $113,000 for the increase in high/low voltage investigations in 2012 and an additional $135,000 in 2013. These numbers are used as the basis for the 2014 forecast. DRA asked PG&E to identify the number of voltage investigations that occurred in 2012, the cost per investigation, and the overall 2012 costs for SmartMeter High/Low Voltage investigations. [893] PG&E responded that it conducted 748 voltage investigations in 2012 for a total cost of $1,277,000, or an average of $1,707 per investigation. The 2012 recorded cost for Smart Meter High/Low Voltage Investigation was $22,080. Costs in base year 2011 dollars are $1,661 per investigation, and $21,488 for Smart Meter High/Low Voltage Investigations."

PG&E only spent an additional $22,080 in 2012 because of Smart Meter data in contrast to its forecast of $135,000. PG&E overstated its 2012 forecast by $157,080. DRA believes that PG&E's TY forecast is also overstated.

DRA recommends that the Commission adopt its TY forecast of $44,160 for Smart Meter High/Low Voltage Investigation. DRA relies on the 2012 recorded expenses of $22,080 and then doubles it to account for increases in investigations in 2013 and 2014.

4.14.1.3 MAT FZC: Overload and Idle Transformer Investigations

MAT FZC records the expense-related costs of Electric Estimators and Mapping personnel who perform over loaded and idle transformer investigations.[894]

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[891] Ex. 73 (DRA-5), p.64.

[892] Ex. 21 (PG&E-4), p. WP 14-14

[893] Ex. 73 (DRA-5), p. 63 citing DRA-202-EJ1 question 15.

[894] Ex. 73 (DRA-5), p. 65 citing DRA-025-EJ1 question 1.

PG&E's TY estimate for MAT FZC is $0.200 million. DRA's corresponding TY estimate is $0.080 million.[895]

PG&E is forecasting an additional $0.192 million over 2011 recorded expenses for overloaded transformer replacement reviews. DRA asked PG&E to provide the documentation, calculations, or studies that show an increase in overloaded transformer reviews due to SmartMeter data."[896] PG&E's response was that it had no such documentation.[897]

As was the case for smart meter voltage investigations in MAT FZB, PG&E overestimated its ability to and the speed at which it will integrate Smart Data into its electric distribution operations and maintenance. In addition, PG&E did not provide any documentation or analyses to support its request. DRA opposes additional funding for MAT FZC, and therefore recommends that the Commission adopt a forecast of $0.080 million, which is the level of PG&E's 2011 recorded adjusted expenses.

4.14.1.4 MAT FZD: Phase Balancing and Crew Required Fuse Replacements

MAT FZD records the expense-related costs of field personnel who perform phase balancing work and fuse replacement work.[898] PG&E's TY estimate for MAT FZD is $1.515 million. DRA's corresponding TY estimate is $0.337 million.[899]

PG&E's requested an additional $1.276 million over 2011 recorded expenses of $0.239 million for identified phase balancing. For the initial phase of the project, PG&E forecasted conducting 43 phase balancing projects in 2012 for a cost of $1.076 million. DRA asked PG&E to "[i]dentify the number of phase balancing projects occurring in 2012, the cost per phase balancing project, and the overall 2012 recorded costs for identified phase balancing (in nominal and base year 2011 dollars)."[900] PG&E responded that, "[i]n 2012, PG&E initiated

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[895] Ex. 73 (DRA-5), p. 65.

[896] Ex. 73 (DRA-5), p. 66 citing DRA-202-EJ1 question 19.

[897] Ex. 73 (DRA-5), p. 66.

[898] Ex. 73 (DRA-5), p. 67 citing DRA-025-EJ1 question 1.

[899] Ex. 73 (DRA-5), p. 67.

[900] Ex. 73 (DRA-5), p. 67 citing DRA-202-EJ1 question 15.

five phase balancing projects, of which four were completed. Costs were $97,500. Costs in 2011 base year dollars were $94,886."

There is not sufficient documentation or cost-benefit analyses to justify an increase of $1.276 million over 2011 expenses for identified phase balancing. PG&E significantly overstated the number of phase balancing projects it would complete in 2012. It is more likely that PG&E annually completes four to five phase balancing projects. DRA proposes an additional $0.098 million over 2011 expenses for identified phase balancing. DRA recommends that the Commission adopt a forecast of $0.337 million.[901]

4.14.1.5 MAT FZE: Device Setting Changes/Downloads; Seasonal and Emergency Load Transfers; Troublemen Required Fuse Replacements; Back to Normal Switching

MAT FZE records the expense-related costs of field personnel who support a variety of critical field tasks.[902] PG&E's TY estimate for MAT FZE expenses is $1.207 million. After reviewing PG&E's testimony, workpapers, and discovery responses, DRA agrees with PG&E's request.

4.15 Electric Distribution Reliability

4.15.1 MWC 08 – Distribution Reliability Base

Capital projects included in MWC 08 address local reliability issues that occur routinely throughout PG&E's service territory. Typical projects include: installing fused cutouts, line reclosers, sectionalizers, switches, fault indicators, fused switches, and interrupters; rebuilding and reframing overhead distribution lines; and performing other reliability and system protection improvement work.[903]

DRA is recommending that recorded 2012 capital expenditures of $18.547 million be used (versus PG&E's forecast of $21.565 million). For 2013 and 2014, DRA is recommending capital expenditures of $25.200 million and $44.492 million, respectively, while PG&E has

[901] Ex. 73 (DRA-5), p. 68.

[902] Ex. 73 (DRA-5), p. 68 citing DRA-025-EJ1 question 1.

[903] Ex. 17 (PG&E-4), p. 15-15, lines 5 through10.

forecasted expenditures of $25.205 million and $68.186 million.[904] DRA is recommending two adjustments to MWC 08, both of which only impact 2014.

DRA's first adjustment involves the Overhead Conductor Replacement Program. PG&E's electric distribution system includes over 113,500 miles of overhead conductor.[905] To improve system safety and integrity, PG&E is forecasting an increase for overhead conductor replacement work that will address annealed or deteriorated conductors. To calculate the costs of this program, PG&E takes a straightforward approach: it develops a cost (per foot) to replace overhead conductors, and multiplies that cost by the amount of replacement footage it forecasts it will replace each year

DRA examined PG&E's forecasted costs to replace a circuit foot of distribution line, and agrees that those costs are reasonable. DRA also agrees with PG&E's proposal to replace 80,000 circuit feet in 2013. However, PG&E is proposing to replace 325,000 circuit feet in 2014, over four times the quantity estimated in 2013.[906] Not only is this over four times greater than its 2013 forecast, but it is also four times greater than the highest previously recorded replacement amount (81,312 circuit feet in 2008) since at least 2008. DRA recommends that 160,000 circuit feet of overhead conductor be replaced in 2014, which is a more moderate increase than proposed by PG&E. That quantity represents a 100% increase over PG&E's request for the prior year, and is nearly double the previously highest recorded amount replaced (81,312 circuit feet in 2008).

DRA's second adjustment to MWC 08 involves the quantity of line reclosers that PG&E proposes to purchase each year. DRA examined PG&E's forecasted unit cost to replace a single line recloser, and agrees that those costs are reasonable. DRA also agrees with PG&E's proposal to replace 545 reclosers in 2013. In 2014, PG&E is proposing to replace 1,110 reclosers in 2014, more than double the previous year.

As will be discussed in MWC 49, DRA is recommending reductions to the number of Fault Location, Isolation and Service Restoration (FLISR) systems PG&E is proposing to install in 2014. DRA recommends that 100 systems be installed, half of PG&E's forecast of 200. As

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[904] Ex. 75 (DRA-7), p.45, Table 7-11, line 7.

[905] Ex. 17 (PG&E-4), p. 15-16, lines 14 and 15.

[906] Ex. 21 (PG&E-4 workpapers), p. WP 15-7, line 2.

shown in PG&E's workpapers, there are three reclosers per FLISR system.[907] Therefore, a decrease of 100 FLISR system installations in 2014 will result in a decrease of 300 recloser purchases in that year. DRA has reflected that decrease of 300 reclosers in its MWC 08 forecast for 2014.

In its Rebuttal testimony regarding DRA's MWC 08 proposed reductions, PG&E asserts that replacing overhead conductors mitigates the public and system safety risks of "wire down" events, and that its 62 miles of proposed replacements each year represents less than 1% of the total miles in PG&E's system.[908]

In response, DRA points out that in making its forecasts for overhead conductor replacements, it has relied on PG&E's expertise to help determine an appropriate level of replacement to reduce "wire down" events. In 2013, PG&E has proposed to replace 80,000 feet of conductor, nearly identical to the highest previously recorded replacement amount (81,312 feet in 2008). DRA is confident that PG&E would never propose a replacement forecast that would fail to consider "wire down" issues. After the events in San Bruno, DRA cannot imagine that PG&E would ever propose a budget that failed to provide adequate levels of funding for safety and reliability. If PG&E is satisfied with 80,000 feet in 2013, it should be extremely satisfied with DRA's proposal to double that forecast and replace 160,000 feet in 2014. It is important to note that DRA's 2014 recommendation is nearly twice as high as PG&E's highest previously recorded replacement.

In Rebuttal, PG&E also alleges that its proposed higher than historical replacement rate for overhead conductor replacements is consistent with PG&E's recent focus on increased safety and reliability.[909]

DRA is aware of PG&E's (and the Commission's) increased emphasis on safety and reliability. DRA's proposal to replace 160,000 feet of overhead conductor in 2014 reflects the increased focus on safety and reliability. It is important to note that DRA's 2014 forecast is twice as high as PG&E's highest previously recorded replacement amount (81,312 feet in 2008); it is also twice as high as PG&E itself proposes for 2013. PG&E has been acutely aware of the

[907] Ex. 21 (PG&E-4 workpapers), p. WP 15-9, line 21.

[908] Ex. 55 (PG&E-19), p. 15-5, Q/A. 17.

[909] Ex. 55, (PG&E-19), pp. 15-5 – 15-6.

Commission's increased emphasis on safety and reliability. DRA is confident that PG&E would never propose a 2013 budget that failed to reflect that increased emphasis. Since DRA's 2014 recommendation is twice as large as PG&E's 2013 forecast, DRA is sure that its proposed 2014 budget proposal reflects both PG&E's and the Commission's goals.

In its Rebuttal of DRA's second proposed MWC 08 adjustment (the reduction in numbers of line reclosers), PG&E acknowledges that adjustments to its Fault Location, Isolation, and Service Restoration (FLISR) program will impact line recloser purchases.[910] However, because PG&E does not support any changes to its FLISR program (which will be discussed in MWC 49), PG&E does not agree that any reductions should be made to its line recloser purchases.

DRA agrees that line reclosers are tied to the FLISR program. Since each FLISR installation usually involves the addition of three line reclosers, any change to the number of FLISR installations will have a 3-fold change to the number of line reclosers. As will be discussed in MWC 49, DRA is proposing a reduction of 100 FLISR installations in 2014. Therefore, DRA is reducing the proposed number of line reclosers needed for 2014 by 300.

In CUE's Rebuttal testimony[911], CUE presents several arguments that criticize DRA's treatment of overhead line replacements. CUE's first criticism is that DRA wants to cut overhead line replacements in half even though PG&E has developed a benefit to cost (B/C) ratio of 2.0.

In response, DRA would point out that CUE itself has questioned the accuracy of the B/C ratios calculated by PG&E.[912] DRA questions the benefit assumptions that were used in PG&E's overhead line replacement B/C calculations. As shown in PG&E's workpapers, on page WP 15-17, [913] PG&E's assumed benefits are based on a 2009 study.

DRA would assume that PG&E would replace the worst lines first, and as these lines are replaced, the benefits for subsequent replacements would decrease. Therefore, the benefits that were present during the 2009 study would be higher than the benefits that are currently available. When lower benefits are substituted, it is clear that the "true" B/C ratio will be something

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[910] Ex. 55 (PG&E-19), p. 15-6, Q/A. 21.

[911] Ex. 148 (CUE-3), p. 9.

[912] See, e.g., Ex. 146 (CUE-1), p. 26, footnote 115.

[913] Ex. 21 (PG&E-4 workpapers).

significantly less than 2.0. The $64,000 question then becomes, "What should the correct ratio actually be?" As discussed above, the B/C ratio will likely continue to decrease as more lines are replaced, and the most unreliable circuits are addressed. More to the point, in an ideal world, it would be nice to know at what point the B/C ratio for a line replacement drops below 1? Neither PG&E nor CUE attempts to calculate this transition point; given the assumptions and uncertainties that are involved, such a calculation is probably not possible.

Based on these uncertainties, and given the fact that no one has attempted to derive this transition point, DRA has relied on its own judgment. DRA notes that PG&E provided recorded data going back to 2008 showing the amount of overhead lines that were replaced. The highest recorded replacement level was 81,312 feet in 2008. In 2013, PG&E itself has concluded that 80,000 feet should be replaced; DRA has agreed with that figure. For 2014, DRA is doubling the 2013 forecast (to 160,000 feet). If PG&E feels that 80,000 feet is reasonable for 2013, why would 160,000 feet not be reasonable in 2014? Despite CUE's protest to the contrary, DRA has judged that replacing 80,000 feet of overhead conductor is prudent and reasonable given the uncertainties surrounding the "true" B/C ratio.

CUE's next criticism involves DRA's statement in its testimony (Exhibit 75, page 52, lines 23 through 25) that "no one would seriously suggest that all 113,500 miles of overhead conductor be replaced in one year, even assuming the benefit to cost ratio is positive." CUE alleges that DRA's statement is a complete non sequitur.

DRA will freely admit that it did not construct its testimony in the format of a logical syllogism. However, that in no way diminishes the logic of DRA's conclusions. The fact is, for a variety of reasons, no one <u>would</u> seriously consider replacing all 113,500 miles in one year. The sole purpose of DRA's extreme example was to point out that even with a B/C ratio greater than 1, at some point, it no longer makes sense to undertake these projects. CUE discusses this issue at some length on page 22 of its testimony (Exhibit 146), pointing out that when the B/C ratio drops below 1, it no longer makes economic sense to spend money on that particular project. No one, not even CUE, has attempted to calculate how many projects need to be undertaken before the B/C ratio reaches that "break even" point.

CUE next asserts that the fact that no one is proposing 113,500 miles of replacement is in no way evidence that 62 miles is too many.

DRA agrees with CUE's assertion. However, DRA would argue that the fact that no one is proposing 113,500 miles of replacement does show that there is a practical limit to the number of miles that should be replaced in a given year. As discussed above, DRA simply used an extreme example in its testimony (replacing 113,500 miles in one year) to illustrate that there are limits to the number of capital projects that should reasonably be undertaken in a given year, even if the B/C ratio is initially greater than 1.

CUE's last criticism of DRA's adjustment involves the length of time that it would take to replace the overhead lines. Using a replacement rate of 62 miles per year, CUE argues that it would take 2000 years to replace PG&E's entire overhead system; using DRA's proposed replacement rate, it would take 3,700+ years. CUE alleges that it is clear that DRA's recommendation is a move in the wrong direction.

DRA would like to point out that only if one assumes that all of the assumptions inherent in the calculation remain unchanged for the next 3,700+ years would that be the result. DRA is not inclined to make that assumption. Over the years, DRA assumes that any number of variables will change – the rate of replacement will vary, undergrounding will increasingly replace overhead lines, base reliability expenditures will change, etc. In DRA's judgment, it is the height of folly to assume that everything will remain constant for the next 3,700+ years. The fact remains that DRA is proposing to replace overhead lines at a rate that is twice as great as anything seen in the past, and twice as great as PG&E found reasonable in the prior year. As discussed previously, if PG&E was confident that replacing 80,000 feet in 2013 was prudent and reasonable, it can only be concluded that replacing 160,000 feet in 2014 would also be prudent and reasonable.

4.15.2 MWC 49 – Distribution Reliability Circuit/ Zone

Capital projects contained within MWC 49 include reliability improvements beyond those addressed in MWC 08. Those projects include the installation of Fault Location, Isolation and Service Restoration (FLISR) systems, improvement of poor performing circuits, installation of overhead fuses, installation of overhead line reclosers and underground protective devices,

installation of fault indicators, replacement of recloser controls, and work in communities to resolve high-impact reliability issues.[914]

DRA is recommending that recorded 2012 capital expenditures of $61.923 million be used (versus PG&E's forecast of $59.907 million). For 2013 and 2014, DRA is recommending capital expenditures of $61.700 million and $73.049 million, respectively, while PG&E has forecasted expenditures of $61.719 million and $103.840 million.[915] DRA has recommended only one adjustment to MWC 49 – a reduction to PG&E's proposal to install 200 FLISR systems in 2014.

The FLISR program was authorized by the Commission in the Cornerstone decision.[916] Attachment A to that decision outlines the level of capitalized expenditures that were authorized. Attachment A states that over the four-year period 2010 through 2013, PG&E was authorized to install FLISR systems, totaling $136.341 million, on the 400 worst performing circuits, with appropriate prioritization of projects based on the severity of the problem and cost effectiveness analysis.

The Cornerstone program ends in 2013, and expenditures associated with Cornerstone are excluded from this GRC (with the exception of using 2012 recorded data). However, as discussed in its testimony, PG&E is proposing to continue the FLISR program.[917] PG&E proposes shifting this program to MWC 49 beginning in 2014, and forecasts expenditures of $60.000 million per year in order to install 200 FLISR systems per year.

DRA agrees with PG&E's request to continue making these reliability improvements if they can be accomplished in a cost-effective manner. However, in DRA's judgment, PG&E's 2014 FLISR installation request is excessive. As noted in the Cornerstone decision, the 400 worst performing circuits are being addressed in that program over the 2010 through 2013 period. The 400 worst circuits are "low hanging fruit" in the sense that installing FLISR systems on those circuits will garner the most improvements in reliability.

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[914] Ex. 17 (DRA-7), page 15-14, lines 12 through 15, and page 15-15, lines 1 and 2.

[915] Ex. 75 (DRA-7), p, 56, Table 7-13, line 8.

[916] D.10-06-048.

[917] Ex. 17 (PG&E-4), p. 15-12, lines 3 and 4.

PG&E's FLISR proposal for MWC 49 would entail spending $180.000 million to install 600 FLISR systems over the period 2014 through 2016, far more than the $136.341 million that was found reasonable over the four-year period covered by Cornerstone. PG&E's test year 2014 forecast will result in PG&E spending more money to gain fewer benefits. Rather than installing 200 FLISR systems in 2014, as proposed by PG&E, DRA has concluded that 100 installations are more reasonable. DRA's recommendation of 100 installations equals the average number of installations undertaken during the Cornerstone period (i.e., 400 installations over the four-year period 2010 through 2013 equals 100 per year). DRA estimates that 100 FLISR installations in 2014 will allow PG&E to continue its reliability improvement program.

In its Rebuttal to DRA's MWC 49 recommendations, PG&E states that its plan to install 200 FLISR circuits per year will help PG&E obtain the reliability needed to improve service to customers and improve SAIDI and SAIFI.[918]

In response, DRA would like to quickly point out that its recommendation to install 100 FLISR systems in 2014 will also improve service and improve SAIDI and SAIFI. In the Cornerstone proceeding, the Commission carefully examined how FLISR systems would impact PG&E's electric distribution system, and concluded that installing 100 per year (400 over the 4-year period 2010 through 2013) was reasonable. DRA is simply continuing the installation rate found reasonable in the Cornerstone decision. PG&E has provided no justification for its proposal to increase the installation rate.

In Rebuttal, PG&E states that it did not install any FLISR systems during the first two years of the Cornerstone program.[919] Therefore, PG&E alleges that the pace of work that PG&E is forecasting for 2014 through 2016 is similar to the pace of work planned in 2012 and 2013.

DRA would like to point out that at the time the Cornerstone decision was issued, the Commission would not have known that no FLISR installations would take place until 2012. In fact, Attachment A to D.10-06-048 clearly shows that large capital expenditures were expected for FLISR systems in 2010 and 2011. In the Cornerstone proceeding, which was focused solely on reliability, the Commission found that 400 FLISR installations over the 4-year period were reasonable. Now that work has been completed on the 400 poorest performing

[918] Ex. 55 (PG&E-19) p. 15-7, Q/A. 28.

[919] Ex. 55 (PG&E-19), p. 15-9, Q/A 29.

circuits (circuits that should contribute the greatest SAIDI and SAIFI improvements), DRA finds it difficult to understand why the Commission would find it reasonable to install FLISR systems at a rate that is higher than the previous period.

PG&E's last Rebuttal criticism is that there are still significant reliability benefits to be gained from installing additional FLISR systems, especially since PG&E's Value of Service (VOS) study show a B/C ratio in excess of 30.[920]

DRA agrees that benefits will be captured in the next batch of FLISR installations; DRA stated as much in its testimony when it discussed that 100 FLISR installations would allow PG&E to continue its reliability improvement program.[921] DRA has acknowledged that there is a positive benefit-to-cost (B/C) ratio, which is why it has recommended that the FLISR program continue even after the Cornerstone program ended in 2013. The question is not whether PG&E should continue striving for reliability improvements, but rather what level of improvements can be expected and at what cost.

In its Rebuttal, PG&E notes that the FLISR program has a B/C ratio that exceeds 30.[922] Indeed, PG&E's workpaper page WP 15-15, line 9[923] shows a B/C ratio of 31.16. However, that ratio is highly suspect. As CUE points out in its Opening Testimony[924], the B/C ratio is more likely to be no more than 21.8. DRA believes that the ratio is actually much lower. PG&E Workpaper page WP 15-17 provides information regarding the assumptions that went into the calculations of the various B/C ratios. Line 72 on that page states that the calculation for the Customers Experiencing Significant Outages (CESO) component of the B/C ratio, is based on improvements from the 5-year average circuit outage data of previous FLISR installations. As discussed in DRA's testimony, the 400 FLISR systems installed during the previous 4-year period address the circuits with the worst reliability, and will therefore garner the most improvements in reliability.[925] Stated another way, future FLISR installations will not generate

[920] Ex. 55 (PG&E 19), p. 15-9, Q/A. 30.

[921] Ex. 75 (DRA-7), p. 57, lines 17-19.

[922] Ex. 55 (PG&E-19), p. 15-10, lines 1-2.

[923] Ex. 21 (PG&E-4 workpapers).

[924] Ex. 146 (CUE-1), p. 26, footnote 115.

[925] Ex. 75 (DRA-7), p. 57.

comparable reliability improvements. PG&E confirms this in its Rebuttal when it admits that previous FLISR installations will capture incrementally more reliability benefits than subsequent FLISR installations.[926] Therefore, the CESO assumption used by PG&E to calculate the B/C ratio for FLISR is not correct. The use of a 5-year average for improvements overstates the reliability benefits that PG&E will experience in future FLISR installations. As PG&E admits, reliability improvements are steadily decreasing (as the least reliable circuits are steadily fixed), and the use of average data (from previous installations) will greatly overstate the improvements that can be expected from subsequent installations. Therefore, even the 21.8 ratio developed by CUE overstates the B/C ratio that can be expected for new FLISR installations.

The $64,000 question is, "What should the correct ratio actually be?" As DRA discussed above, the B/C ratio will continually decrease as more FLISR systems are installed, and the most unreliable circuits are addressed. More succinctly, at what point does the B/C ratio for a FLISR installation drop below 1? Neither PG&E nor CUE attempts to calculate this transition point; given the assumptions and uncertainties that are involved, such a calculation is probably not possible. Based on these uncertainties, and given the fact that no one has attempted to derive this transition point, DRA has relied on the Commission's judgment when, in the Cornerstone decision, it set the FLISR installation rate at 100 per year.

CUE has its own set of Rebuttal criticisms regarding DRA's FLISR reductions. On page 8 of its Rebuttal (Exhibit 148), CUE begins its criticism by alleging that DRA "somehow jumps to the conclusion" that FLISR installations should be cut in half in spite of large B/C ratios.[927]

CUE's criticism is basically the same criticism leveled by PG&E in its Rebuttal, Question and Answer 30. DRA's response to that Rebuttal criticism is lengthy and will not be repeated here. Suffice it to say that DRA did not "jump to the conclusion" that FLISR installations should be reduced; DRA's recommendation was based on careful analysis and prudent judgment.

CUE's next rebuttal issue involves DRA's statement that "no one would recommend that all 600 FLISR systems that PG&E proposes to install during the 2014 through 2016 period should be immediately installed even assuming the benefit to cost ratio is positive." CUE goes on to state that this is neither obvious nor a sequitur.

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[926] Ex. 55 (PG&E-19), p. 15-9, lines 17 – 19.

[927] Ex. 148 (CUE-3), p. 8.

Once again, DRA admits that it did not construct its testimony in the format of a logical syllogism. However, that in no way diminishes the logic of DRA's conclusions. The fact is, for a variety of reasons, no one would seriously consider replacing all 600 FLISR systems in one year. The sole purpose of DRA's extreme example was to point out that even with a B/C ratio greater than 1, at some point, it no longer makes sense to undertake these projects. CUE discusses this issue at some length on page 22 of its testimony (Exhibit 146), pointing out that when the B/C ratio drops below 1, it no longer makes economic sense to spend money on that particular project. No one, not even CUE, has attempted to calculate how many projects need to be undertaken before the B/C ratio reaches that "break even" point.

CUE's last Rebuttal criticism states that, even if it were true that a high B/C ratio does not justify tripling the FLISR program, it does not follow that a high B/C ratio is a reason to shrink it.

DRA cannot be certain whether or not CUE is being serious when it apparently suggests that DRA has recommended reducing FLISR systems <u>because</u> the B/C ratio is greater than 1. On the small chance that CUE actually believes that DRA made its recommendation because the B/C ratio was greater than 1, DRA would like to state, for the record, that factors other than a high B/C ratio were responsible for DRA's recommendation. As discussed at great length previously, DRA has been concerned over PG&E's development of its B/C ratio, and DRA believes that the correct ratio is much lower than PG&E's calculations would suggest. In addition, neither PG&E nor CUE has attempted to calculate the transition point where the B/C ratio becomes 1. Based on these uncertainties, DRA has relied on the Commission's judgment when, in the Cornerstone decision, it set the FLISR installation rate at 100 per year.

4.16 Underground Asset Management

PG&E's electric underground distribution system consists of primary distribution cables and associated switches, vaults, enclosures, conduits, splices, cable connectors, and other equipment. Capital projects for MWC 56 primarily consist of replacing cables and switches in order to provide safe and reliable service. When underground cables fail, and the nature of the failure requires the immediate replacement (or repair) of the cable, that work is charged to MWC 17. MWC 56 only includes capital costs for failed cables that do not require immediate repair.

DRA is recommending that recorded 2012 capital expenditures of $72.018 million be used (versus PG&E's forecast of $74.200 million). For 2013 and 2014, DRA is recommending capital expenditures of $68.895 million and $89.814 million, respectively, while PG&E has forecasted expenditures of $68.918 million and $140.078 million.[928] DRA has recommended two adjustments to MWC 56. The first adjustment involves the appropriate level of expenditures for Traditional MWC projects. The second adjustment pertains to the number of underground switches that should be replaced each year.

Tie-Cable Replacement, Critical Operating Equipment (COE) Cable Replacement, and Reliability-Related Cable Replacement are the traditional capital categories found in MWC 56. DRA examined PG&E's proposed 2013 capital forecasts for these three categories and accepts them. However, PG&E is forecasting large increases for two of these three categories starting in 2014. For the area of Reliability-Related Cable Replacements, PG&E's 2014 forecast is slightly higher than in previous years, and DRA has concluded that the forecast is reasonable. However, for the other two project categories, PG&E's rationale for the large 2014 increases appears to be to catch-up with project backlogs.

In its testimony, PG&E states that it rescheduled and reprioritized the Tie-Cable Replacement work it had scheduled to do in the last GRC.[929] PG&E also notes that it wants to reduce the backlog of existing COE Cable Replacement projects.[930] In DRA's judgment, there should not have been any backlogs in the first place.

As shown in DRA's testimony in Table 7-15[931], PG&E has historically spent much less than it was authorized for cable replacements. By the end of 2011, PG&E had cumulatively, over the period 2007 through 2011, spent nearly $173 million less than it had been authorized. In DRA's judgment, any forecasted expenditure that is significantly larger than the $30+ million that was expended in 2010 and 2011 is being proposed so as to catch-up with projects that were previously deferred and to eliminate backlogs. DRA has concluded that the 2013 forecast of $38.60 .million (used by both PG&E and DRA) is also reasonable for 2014.

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[928] Ex. 75 (DRA-7), p. 59, Table 7-14, line 5.

[929] Ex. 17 (PG&E-4), p. 16-16, lines 12 through 14.

[930] Ex. 2 (PG&E-4 workpapers), p. WP 16-29, footnote 1.

[931] Ex. 75 (DRA-7), p. 61.

As discussed in DRA's testimony[932], the Commission has increasingly been reluctant to allow utilities to seek ratepayer funding for previously authorized projects that have been deferred. This same reluctance should be applied to MWC 56. Furthermore, PG&E has provided no assurance that underground replacement deferrals will not continue in the future. Based on PG&E's expenditure history, DRA is uncertain that the deferral/backlog problems would be addressed even if PG&E was authorized to increase its 2014 MWC 56 spending to its requested levels.

DRA's recommended 2014 expenditure level of $38.60 million is $37.80 million less than PG&E's forecast. However, this lower level does not indicate that the backlog/deferral of traditional MWC 56 capital expenditures should be ignored, or delayed to a future GRC. DRA's lower forecast reflects DRA's recommendation that ratepayers not be required to once again foot the bill for capital projects that have been deferred for many years.

DRA's second recommended adjustment involves replacement levels for underground switches. Transfer Ground Rocker Arm Main / Transfer Ground Rocker Arm Line (TGRAM/TGRAL) switches consist of an operating assembly contained in a welded steel tank filled with nearly 100 gallons of insulating oil. These switches were developed for use in underground vaults in order to operate the underground electric distribution system. PG&E plans to replace 100 switches in 2012, 80 in 2013, and 140 each year in 2014 through 2016.

PG&E states that it has determined that the TGRAM/TGRAL switches need to be retired due to reliability and safety concerns. PG&E inspected each of these switches, and ranked them based on their condition. Appendix A at the end of DRA's testimony[933] contains a copy of this condition-based ranking. As shown in Appendix A, as of the end of 2011, 155 of the 771 switches have already been replaced, with 616 switches remaining to be replaced. PG&E states that it plans to replace an additional 100 switches in 2012, resulting in 516 remaining.

As mentioned previously, PG&E is forecasting the replacement of 80 TGRAM/TGRAL switches in 2013. Although this is lower than the projected 100 replacements for 2012, DRA concludes that this 2013 replacement level is reasonable. However, DRA has concluded that the 140 replacements forecasted by PG&E in 2014 are excessive.

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[932] Ex. 75 (DRA-7) Section V.

[933] Ex. 75 (DRA-7).

DRA is recommending that 100 TGRAM/TGRAL switches be replaced each year beginning in 2014. This equates to all of the remaining switches being replaced in slightly more than four years (roughly one year longer than PG&E's proposed schedule) because there are 436 switches that are scheduled for replacement as of the beginning of 2014.[934] In its testimony, PG&E indicates that it would like to replace all of the switches by the end of 2016. In DRA's judgment, extending the replacement schedule by an additional year beyond what PG&E is requesting poses no significant risk and is reasonable.

As shown in Appendix A to DRA's testimony, 441 of the 661 total switches that will ultimately be replaced fall into the lowest (Tier 8) category, meaning that these switches have no significant visible oil leaks or corrosion.[935] Stated another way, as of the end of 2011, the total combined number of switches falling into Tiers 1 through 7 equals 175 switches, and should be addressed by the 180 switches replaced in 2012 and 2013.[936]

In its Rebuttal testimony on DRA's MWC 56 recommendations, PG&E acknowledges that there were several years that PG&E spent less than the GRC authorized amount on cable replacement.[937] However, PG&E alleges that DRA's testimony mischaracterized spending on cable replacements by focusing on so-called Traditional MWC 56 expenditures and failing to consider PG&E's expenditures on TGRAM/TGRAL replacements and Network Cable Replacements.

PG&E's allegation that DRA mischaracterized its spending is completely untrue. As discussed at length in DRA's testimony, DRA is becoming increasingly concerned over PG&E's pattern of deferring the same capital spending over multiple rate case cycles.[938] DRA was

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[934] As of the end of 2011, there were 616 TGRAM/TGRAL switches remaining to be replaced. Subtracting the 100 that are scheduled for replacement in 2012 and the 80 scheduled for replacement in 2013 leaves 436.

[935] Ex. 75 (DRA-7).

[936] As of the end of 2011, Appendix A shows that 616 switches need to be replaced. Subtracting the 441 switches in Tier 8, there remain 175 switches in Tier 1 through Tier 7 combined. Since 100 switches are scheduled to be replaced in 2012, with 80 more replaced in 2013 (for a total of 180), the Tier 1 through Tier 7 switches should be largely replaced by 2014.

[937] Ex. 55 (PG&E-19), p. 16-1, Q/A 24.

[938] Ex. 75 (DRA-7), Section V.

interested in analyzing PG&E's historical expenditures for MWC 56 projects, and wanted to see if there was a pattern of deferring authorized expenditures for that MWC.

As can be seen in DRA's testimony in Table 7-14 on lines 2 and 3[939] Network Cable Replacements didn't commence until 2010, and TGRAM/TGRAL Switch Replacements didn't start until 2009. In fact, PG&E explicitly states[940] that its forecast for this rate case includes these two new initiatives that were not included in prior GRCs. Since the historical data that were being analyzed by DRA preceded the introduction of these two new project categories, it was necessary to exclude them from the more recent expenditures as well so that all of the recorded data was comparable. However, as Table 7-14 clearly shows, DRA did not ignore Network Cable Replacements or TGRAM/TGRAL Switch Replacements; they were simply analyzed separately.

In Rebuttal, PG&E alleges that if DRA had not separated out TGRAM/TGRAL switch expenditures and Network Cable Replacements, PG&E's 2010 spending on cable replacements would be $27.0 million less than PG&E's authorized amount, not $32.6 million as claimed by DRA, and PG&E's 2011 spending on cable replacement would be approximately $5 million more than authorized, not $17.2 million less as claimed by DRA.[941]

For some reason, PG&E continues to insist that TGRAM/TGRAL switch costs and Network Cable Replacement costs should not be analyzed separately from the traditional MWC 56 projects. PG&E's Rebuttal on this area keeps focusing on looking at the total expenditures for MWC 56. However, Table 7-15 of DRA's testimony only looks at the traditional costs of underground cable replacement, which excludes TGRAM/TGRAL Switch Replacements and Network Cable Replacements. PG&E's testimony explicitly states that its forecast for this current GRC includes these two new capital initiatives for the first time.[942] Therefore, in order to properly analyze whether or not PG&E has been deferring traditional undergrounding projects, DRA needed to remove these new capital categories (categories that were not included in the historical expenditures) so that DRA was analyzing consistent data. The whole purpose of Table

[939] Ex. 75 (DRA-7), p. 59.

[940] Ex. 17 (PG&E-4, p. 16-5, lines 15-16.

[941] Ex. 55 (PG&E-19), pp. 16-8 – 16-9, Q/A. 24.

[942] Ex. 17 (PG&E-4), p. 16-5, lines 15 and 16.

7-15 is to examine how PG&E has been handling the traditional capital expenditures. TGRAM/TGRAL Switch Replacements and Network Cable Replacements are new project categories that are not included in the historical data; they are analyzed separately as shown on Table 7-14, on lines 2 and 3.[943] PG&E's insistence on merging the various capital categories seems to be an attempt to obscure the fact that PG&E has been deferring capital expenditures for the traditional MWC 56 projects, a fact clearly pointed out in Table 7-15.

In its Rebuttal testimony on DRA's proposed recommendations concerning deferred projects. PG&E states that after the 2011 GRC was filed, it completed an investigation that showed that TGRAM/TGRAL switches can still pose safety risks.[944] PG&E contends that this is an example of why PG&E redirects funding that had been forecast for other activities in MWC 56 to higher priority work.

DRA does not doubt that PG&E deferred previously authorized capital dollars to TGRAM/TGRAL switch replacements. DRA's position is that in doing so, PG&E is circumventing the GRC process. As has been discussed previously in this Brief, the Commission should not condone PG&E's practice of deferring previously authorized projects (that are still needed) when other projects, deemed by PG&E to have a higher priority, come along. PG&E is simply deferring needed projects in order to keep its revenue requirement as close as possible to the authorized amount. This issue is discussed at length in Section V of Exhibit 75.

In its Rebuttal testimony on DRA's second recommended MWC 56 adjustment (a reduction in TGRAM/TGRAL switch replacements), PG&E asserts that PG&E has placed significant operating constraints on the use of TGRAM/TGRAL switches to ensure worker and public safety until all of the units are replaced.[945] Since these switches are primarily installed in densely populated urban areas, PG&E believes it is appropriate to replace them sooner rather than later.

As shown in Appendix A of DRA's testimony[946] , PG&E has divided the TGRAM/TGRAL switches into 8 tiers by degree of risk, with Tier 1 switches considered to be at

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[943] Ex. 75 (DRA-7), p. 59.

[944] Ex. 55 (PG&E-19), p. 16-9, Q/A. 26.

[945] Ex. 55 (PG&E-19), p. 16-4, Q/A. 16.

[946] Ex. 75 (DRA-7), Appendix A, p. 72.

high risk and Tier 8 at low risk. As discussed in DRA's testimony,[947] all of the switches falling into Tiers 1 through 7 should be replaced by the end of 2013. Therefore, the 100 replacements recommended by DRA for 2014 (versus PG&E's forecast of 140) will all be to Tier 8 switches. PG&E is itself proposing to replace 80 switches in 2013, most of which will be in Tiers 1 through 7.[948] Therefore, if PG&E felt that safety would not be compromised by replacing 80 switches (in Tiers 1 through 7) in 2013, how can there be a safety concern by replacing 100 Tier 8 switches in 2014, as DRA proposes? DRA does agree that in an ideal world, PG&E's gas and electrical system would consist of nothing but the most modern and up-to-date facilities. However, in the real world, costs must be considered. In PG&E's judgment, it has determined that it is reasonable to replace 80 switches in 2013 that fall into the Tier 1 through Tier 8 categories. Therefore, it must also be reasonable to replace 100 switches in 2014 that fall into Tier 8 (the least risky category). PG&E cannot suddenly claim that DRA's 2014 forecast is unsafe and unreasonable when DRA's forecast is larger than PG&E's 2013 forecast, and addresses switches that are in the lowest tier.

4.17 Distribution Automation and System Protection

4.17.1 Expense

4.17.2 Capital Expenditures

1.1.1.2 MWC 09 – Distribution Automation and Protection

DRA accepted PG&E's three year total amount for the years 2012-2014 for PG&E's largest item request included MWCs 09. DRA accepted PG&E's three year total for installation of substation SCADA, which accounts for almost 78% of PG&E's distribution automation and protection 2012-2014 costs. Since PG&E underestimated 2012 expenditures, DRA lowered the amount capitalized in 2013 and 2014. PG&E seems to complain that its requested three year total is unacceptable, but they do not explain what additional work is necessary during the total three-year period; their testimony is they want the three-year total amount revised to include the excess amount spent in 2012. Costs fluctuate between years; some years go up, while others go down. One cost projection went down for MWC 09, Replacement of Substation SCADA since

[947] Ex. 75 (DRA-7), p. 64.

[948] Ex. 75 (DRA-7), p. 64, footnote 69.

these costs went down, DRA accepted PG&E's actual 2012 costs, and accepted PG&E's 2013 and 2014 cost projections.

PG&E mischaracterizes DRA's testimony, stating that "DRA's proposed reductions to these forecasts are based on its use of a 3-year average of historical costs." If DRA used a historic three year average (2009-2011), DRA would have decreased PG&E's request by close to $70 million rather than the actual DRA adjustment of $18.8 million or 11.9%.

Installation of feeder SCADA

During 2011 and 2012, PG&E only spent $56,500 on the installation of feeder SCADA projects. PG&E sought to increase these costs to $9 million total for the years 2012-2014. PG&E has not demonstrated any willingness to increase these costs in the future. PG&E only spent 4.2% of their forecast 2012 costs in 2012.

Replacement of Feeder SCADA

From 2008-2010, PG&E spent only $79,000 on replacement of feeder SCADA. During 2011, PG&E expenditures rose to 2.8 million, but dropped to $882,000 in 2012. PG&E wants this Commission to increase these costs so it can recover $5 million in costs in 2013 and 2014. PG&E has not demonstrated a commitment to spending this level of funds for replacement of feeder SCADA costs and this Commission should reject their request at this time.

Fire Risk Management (FRM)

Prior to 2010, PG&E did not have any fire risk management costs, between 2010 and 2012, PG&E spent $170,300. PG&E is seeking funding of $5.2 million in 2013 and 2014. During 2012, while PG&E forecast fire risk management costs of $1.2 million, PG&E only spent $64,000 or 5.3% of their forecast expenditure. PG&E has failed to show a commitment to spend the amount it is requesting in this GRC and the Commission should reject its request.

Replacement of Substation Protective Relays

For 2013 and 2014, PG&E wants its ratepayers to pay $4 million in replacement substation protective relays. From 2007 through 2012 PG&E has only spent $1.4 million. There is no evidence in the record that justifies PG&E's requested 857% increase in replacement of substation protective relay costs. PG&E claims that many of the transformers are more than 40 years old, functionally obsolete, and have no spare parts. In addition failures of these relays could result in substation transformer equipment damage, employee injuries and long duration outages. To help PG&E is planning to replace approximately eight substation power

transformers each year from 2013-2016. With PG&E's claimed obsolesce, lack of spare parts, threat to equipment and employees and long duration outages, PG&E has decreased spending in this area in 2011 and 2012. PG&E's words and actions do not correspond. If lack of funds in an area creates hazards, it is PG&E's responsibility to reallocate funds to that area to safeguard its equipment and employees and increase reliability. PG&E has not been increasing funding in this area.

4.18 Rule 20A

4.18.1 Capital Expenditures

Rule 20A provides that utilities will convert existing overhead electric distribution lines, telecommunication lines, cable lines, etc. to underground facilities when such undergrounding has been determined to be in the public interest. To make this determination, a city or county government reviews a potential Rule 20A project to ensure it meets the criteria described in the tariffs. In addition, the local government must create an underground district and meet with the public and utility representatives.[949]

DRA is recommending that recorded 2012 capital expenditures of $52.426 million be used (versus PG&E's forecast of $61.799 million). For 2013 and 2014, DRA is recommending capital expenditures of $53.896 million and $53.756 million, respectively, while PG&E has forecasted expenditures of $88.451 million and $88.222 million.[950]

PG&E calculates and allocates what it terms "work credits" in accordance with Section 2.b of the Rule 20A tariff. These work credits are allocated annually to the city or county. Because the cost for undergrounding overhead distribution facilities is usually quite expensive, it can take a number of years for a city or county to accumulate sufficient work credits to fund a Rule 20A project. These annual credits (as well as the accumulated credits) are not actual cash dollars; there is no bank account maintained by the cities or by PG&E that contains these credits or their dollar equivalent. To help explain this concept, PG&E uses the analogy of "frequent flyer miles" – an airline passenger accumulates sufficient mileage credits until they can be redeemed for a seat upgrade or a free flight. Rule 20A work credits operate in a similar manner;

[949] Ex. 17 (PG&E-4), p. 18-2, lines 21 through 28.

[950] Ex. 75 (DRA-7), p. 66, Table 7-16, line 3.

a city or county government accumulates sufficient credits until they are "redeemed" for a Rule 20A project.

Over the past several rate case cycles, it has been noted that the level of unspent work credits has been increasing. In its 2003 GRC, PG&E stated that the accumulated amount had reached $296 million (as of 2001) and that it therefore expected to perform a large amount of undergrounding in 2002 and 2003.[951] Similarly, in its 2007 GRC, PG&E stated:

> By 2005, the total accumulation of unspent allocations was approximately $355.6 million. This large accumulation has created an increased demand by the cities and counties for Rule 20A work. As a result, PG&E's forecast of Rule 20A capital expenditures anticipates the cities' and counties' demand for substantial undergrounding work in 2005-2009.[952]

In its 2011 GRC, PG&E stated:

> By the start of 2009, cities had approximately $818.4 million in total accumulated work credits, and in addition, because Rule 20A allows communities to borrow up to five years of work credit allocations at the "then-current levels," communities could borrow (and redeem) up to $404.9 million in allocated work credits in addition to their accumulated unspent balance.[953]

In its current GRC, PG&E states that it is implementing a plan to increase the rate at which requested Rule 20A projects are completed.[954] PG&E also states that it would like to eliminate the backlog of work by 2017, and proposes to greatly increase its forecast of MWC 30 expenditures in 2013 through 2016 by spending $86.000 million per year.[955] As can be seen in DRA's testimony, Table 7-16, line 1, $86.000 million is much higher than any recorded expenditure since at least 2007.

DRA analyzed several factors in order to evaluate the reasonableness of PG&E's proposal to increase spending. First, DRA examined the Rule 20A reports that are sent to the

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[951] Ex. 75 (DRA-7), p. 67, citing PG&E 2003 GRC (A.02-11-017), Exhibit PG&E-2, page 3-32.

[952] Ex. 75 (DRA-7), p. 67, citing PG&E 2007 GRC (A.05-12-002), Exhibit PG&E-4, page 3-32, lines 17 through 22.

[953] Ex. 75 (DRA-7), p. 67, citing PG&E 2011 GRC (A.09-12-020), Exhibit PG&E-3, page 7-7, lines 16 through 21.

[954] Ex 17 (PG&E-4), p. 18-6, lines 2 and 3.

[955] Ex. 75 (DRA-7), p. 66, Table 7-16, Columns 8 and 10.

Commission. In accordance with Ordering Paragraph 7 of Decision 73078 in Case 8209, PG&E is required to submit an annual report to the Commission providing various financial information regarding the amounts of Rule 20A allocations and the amounts that have actually been spent. DRA has included the Rule 20A financial data for 2011 and 2012 in Appendix B in Exhibit 75. On Line 10 of the 2011 report, the data show that PG&E has, cumulatively, spent $574,783,800 less than had been allocated over the years. The comparable figure for 2012 (on Line 11) shows $579,423,402. While neither figure definitively indicates how much PG&E will actually spend in a given year, those figures do indicate that it is spending less than is being allocated, and that the spending imbalance is growing.

DRA examined the total amounts for the category "Funds Committed" (Line 13 on the 2011 report and Line 14 on the 2012 report), which represents the sum of the dollars necessary to finish jobs that are not yet completed, plus the dollars allocated for projects where underground districts have already been formed. In 2011, the total for "Funds Committed" amounted to $521,430,773, while in 2012, the total was $442,126,301. These two figures do not definitively indicate how much will be spent in a given future year. However, since the "committed" amount is lower at the end of 2012 than it was at the end of 2011, it does suggest that the actual levels of capital expenditures in 2013 and 2014 are unlikely to be much higher than the 2012 amounts.

Next, DRA sought to examine how historical recorded MWC 30 capital expenditures compared to what PG&E had been authorized. In DRA's testimony, Table 7-17, presents authorized Rule 20A expenditures and recorded expenditures, and compares the two.[956] As shown at the bottom of the table, from 2007 through 2012, PG&E has consistently spent less for MWC 30 than has been authorized. Based on PG&E's expenditure history, there is no certainty that the backlog of work would be addressed, even if PG&E was authorized to increase its 2013 and 2014 MWC 30 spending to its requested levels. Table 7-17 causes DRA to question the likelihood that, even if PG&E's forecast was authorized, it would suddenly begin spending all of the $86.000 million it is requesting for 2013 and 2014, especially given the fact that the commencement of Rule 20A projects are not entirely within the control of PG&E.

The final piece of DRA's Rule 20A analysis was to examine how PG&E's forecast for 2012 comported with reality. As shown in Table 7-16 (Row 4, Column 6) of DRA's

[956] Ex. 75 (DRA-7), p. 69.

Testimony,[957] Exhibit 75 (page 66), PG&E forecasted $61.799 million for Rule 20A expenditures in 2012. PG&E's forecast presumably incorporated its recent proposals to eliminate the work backlog, as well as its most recent forecasts. However, as the saying goes, "the proof is in the pudding." In spite of the fact that 2012 was the first forecast year for PG&E in this GRC, and would involve the least amount of extrapolation of data trends, the actual 2012 recorded amount for MWC 30 was $52.426 million,[958] $9.373 million less than PG&E's forecast.

In its Rebuttal testimony, PG&E alleges that its historical Rule 20A expenditures are not an appropriate basis for funding in 2013 and 2014 because PG&E is forecasting a significantly higher amount of Rule 20A work and has implemented a plan to increase the rate at which requested Rule 20A projects are completed.[959]

DRA agrees that PG&E has stated that they have implemented such a plan. However, this is not the first GRC in which PG&E states that it plans to implement various initiatives to improve the Rule 20A process. In the 2011 GRC, PG&E discussed Rule 20A expenditures in Exhibit PG&E-3, Chapter 7. On page 7-4 of that document, PG&E presents a section called "Rule 20A Program Improvements" that details the various programs that PG&E planned to implement in order to reduce the overall duration of Rule 20A projects. DRA assumes that these programs were implemented, as it could find no discussion in the GRC Settlement that disallowed those programs. Yet, as shown in DRA's Testimony in the current GRC, the amount of authorized Rule 20A funds that went unspent in 2011 and 2012 has never been higher ($46.372 million unspent in 2011, and $27.574 million unspent in 2012).[960] PG&E has presented no evidence to suggest that the plan outlined in the current GRC will be more successful than the prior plan.

In its Rebuttal, Question and Answer 9, PG&E states that DRA appears to erroneously claim that "allocations" in Total Unexpended Funds represents funding that the CPUC has

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[957] Ex. 75 (DRA-7), p. 66.

[958] Ex. 75 (DRA-7), p. 69, Table 7-17.

[959] Ex. 55 (PG&E-19), p. 18-1, Q/A7.

[960] Ex. 75 (DRA-7), p. 69, Table 7-17.

approved for PG&E to spend, but which PG&E did not actually spend.[961] PG&E states that there is no correlation between the amount of the balance in Total Unexpended Funds and PG&E's funding for Rule 20-A projects.

In response, DRA notes that each year, an amount allocated for conversions (which PG&E terms as "work credits") will be added to the Total Allocation Balance. If this amount increases faster than Expenditures For Conversions, then the Total Unexpended Funds balance will increase, which correlates to potential Rule 20A work that will be undertaken in the future. In its testimony, DRA specifically states that the Total Unexpended Fund balance does not definitively indicate how much PG&E will spend in a given year.[962] However, the fact that this balance is growing does convey useful information. PG&E notes that the Total Unexpended Funds balance is a rough measure of how much potential Rule 20A work will be performed in the future.[963] DRA agrees with PG&E's assessment that this balance indicates future Rule 20A work. The fact that this balance is growing indicates that Allocations For Conversions (the "work credits" that are allocated each year) are exceeding the Expenditures For Conversions. For the years 2011 through 2013, the Commission fixed the annual "work credit" level at $41.3 million, yet the Expenditures For Conversions still failed to keep pace. DRA views this as just one indicator that PG&E's 2014 forecast of $88.222 million is not likely to occur.

In its Rebuttal, Question and Answer 10, PG&E asserts that the "Funds Committed" balance is variable: it goes down in years where more Rule 20A projects are completed than new projects are scheduled, but goes up when the opposite occurs. PG&E also states that the "Funds Committed" balance is not an accurate measure of work that will need to be performed. Even with the ending balance reduction between 2011 and 2012, the amount of "Funds Committed" which has not yet been paid (i.e., which PG&E still needs a budget for) is $274.1 million, which would take more than three years to work down at PG&E's proposed funding levels of $86 million per year.

In response to these allegations, DRA makes the following points. DRA agrees that the "Funds Committed" balance is variable. However, DRA believes that those year-to-year

[961] Ex 55 (PG&E-19), p. 18-4.

[962] Ex. 75 (DRA-7), p. 68.

[963] Ex. 55 (PG&E-19), p. 18-4.

changes provide information regarding the likelihood that PG&E will be spending more or less than in previous years. PG&E's Rebuttal discussion of the $274.1 million "Funds Committed" balance is an example. In its Rebuttal testimony,[964] PG&E shows how it derived the $274.1 million figure (the "Funds Committed" total for which payment has not yet been received) for 2012. Using the same methodology, and applying it to the 2011 Rule 20A data, results in a figure of $325.9 million. Therefore, at the end of 2012, the value of Rule 20A "Funds Committed" projects that still required budgeting was lower than at the end 2011. In its Rebuttal, PG&E fails to explain why it believes that a lower level of "Funds Committed" (that has not yet been budgeted) at the end of 2012 will result in higher capital budgeting in 2013.

DRA does not claim that this analysis definitively proves that PG&E will spend less in 2013, but it does strongly suggest that PG&E's forecast of $86.0 million in 2013 is unlikely.

In its Rebuttal, Question and Answer 11, PG&E acknowledges that it spent less than its authorized amount for Rule 20A projects for several years. However, PG&E states that it is planning to increase the amount of Rule 20A work it performs in order to complete projects that are already underway and to address customer demand for undergrounding of overhead electric distribution facilities in a more timely fashion.

DRA does not doubt that PG&E is planning on doing exactly as it states. The problem is that PG&E has been planning much the same thing for the past several rate cases. As quoted in DRA's Testimony, PG&E anticipated an increased demand for Rule 20A work in the 2007 GRC.[965] In the 2011 GRC, PG&E stated that its 2011 forecast would be significantly higher than previous years because it wanted to include funds to address the accumulation of Rule 20A credits. In spite of these good intentions, as Table 7-17 in DRA's testimony shows, since 2007, PG&E has failed to spend what had been authorized by the Commission. Even as recently as 2012, PG&E has failed to spend what was authorized. This being the case, DRA sees no reason to conclude that PG&E's increased forecasts for 2013 and 2014 will suddenly be more accurate than those in the past. Table 7-17 shows that the most PG&E has spent for Rule 20A projects over the last 6 years has been $52.426 million. This is a far cry from the $86.0 million PG&E is requesting for 2013 and 2014.

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[964] Ex. 55 (PG&E-19), p. 18-5, footnote 19.

[965] Ex. 75 (DRA-7, p. 67.

In Rebuttal, Question and Answer 12, PG&E alleges that it is on pace to spend considerably more in 2013 than it did in 2012. PG&E goes on to state that the 2013 and 2014 forecasts are based entirely on work that has already been identified, much of it on projects that are already partially completed.

DRA saw these claims for the first time in PG&E's Rebuttal testimony. This is new information that DRA has not had an opportunity to analyze. What does the term "considerably more" signify – a million dollars more, 5 million more, 10 million more? DRA has no idea what this means. More importantly, PG&E stated that it was on target to spend its full forecast amount in 2012 until various events caused PG&E to divert resources to other activities.[966] (See Exhibit 55, page 18-7, lines 2 through 4.) Therefore, PG&E's own recent history indicates that just because it is "on pace" to spend considerably more in 2013 at the mid-point of the year, that is no indication that it will still be "on pace" at the end of the year.

4.18.2 Extension of Work Credit Allocation

DRA does not object to the continuation of the policy, adopted in the previous PG&E GRC, of fixing the annual work credit allocation at the level of $41.3 million.

4.19 LED Streetlight Program

4.19.1 Capital Expenditures

PG&E requests the Commission adopt its capital expenditure forecast for the LED Streeetlight Program of $18.6 million for 2014, $22.3 million for 2015, and $18.6 million for 2016 for replacement of non-decorative streetlights with energy efficient LED streetlights.[967] DRA recommends amortizing PG&E's request over a 24 year period, or a forecast of $2.468 million in 2014.[968]

During PG&E's last general rate case, DRA recommended that PG&E receive its funding request over a ten-year period. PG&E did not replace any of its streetlights and deferred this project to this general rate case. Because of PG&E's reluctance to replace its streetlights, DRA recommends the Commission amortize PG&E's request over a 24 year period, which is the life

[966] Ex. 55 (PG&E-19), p. 18-7, lines 2—4.

[967] Ex. 17 (PG&E-4), p. 19-1.

[968] Ex. 76 (DRA-8), p. 18, Table 8-12 and p. 25, lines 5-16.

of the new streetlights. This will allow for the roll-out of the project over a reasonable number of years while providing for coordination with local communities. DRA's estimate will provide funding for the replacement of almost 7,000 streetlights per year over the GRC cycle. PG&E can request modification to the program in its next GRC, if needed.[969]

4.19.2 Rate Design

4.20 Electric Distribution Support Activities

4.20.1 Expense

Electric Distribution Support Activities include training curriculum creation, revision, and other distribution support expenses. The program is recorded in two Major Work Categories (MWCs): DN for Technical Training Curriculum with a forecast of $4.135 million and MWC AB with a forecast of $(10.191) million.

PG&E forecasts $(6.056) million for TY2014 expenses. The corresponding DRA estimate for Electric Distribution Support Activities is $(10.696) million, which is ($4.135) million greater than PG&E's TY forecast.[970]

4.20.1.1 MWC DN – Develop and Provide Training

PG&E records expenses for the Technical Training Curriculum in Major Work Category (MWC) DN. The expenses cover new training materials and course curriculums provided to PG&E employees.[971] PG&E developed its forecast by multiplying the estimated course length by the estimated contract rate for each course.[972]

Since there were no recorded historical expenses for MWC DN, DRA asked PG&E where it currently records annual expenses for PG&E's training curriculum.[973]

PG&E responded:

> "PG&E has not recorded historical costs for developing training materials and course curriculums in MWC DN. Expenditures have been recorded to both Provider Cost Centers (PCCs) and order numbers in either the Electric Operations

[969] Ex. 76 (DRA-8), p. 25.

[970] Ex. 73 (DRA-5), p. 70.

[971] Ex. 17 (PG&E-4) page 20-2

[972] Ex. 21 (PG&E-4 workpapers) WP 20-8

[973] Ex. 73 (DRA-5), p. 71 citing DRA-150-EJ1 Question 1

> and/or Human Resources organization. This is why there are no recorded costs for MWC DN in the workpapers for MWC DN. This is still currently the practice, with Human Resources providing curriculum oversight and some training development and training maintenance. Each Line of Business supported by PG&E Academy, including Electric Operations, funds all other training development.
>
> With respect to the annual costs incurred from 2007-2012 PG&E has identified the courses and estimated the costs. The courses and values for 2007-2011 were provided in response to data request DRA 84, question 5(g), Supplement 01. Attachment GRC2014-Ph-I_DR_DRA_150-Q01Atch01 provides the same information from DRA 84, question 5(g) plus 2012 data. Note that the Development tab from this attachment provides the requested information."

Although PG&E reduced its request in Rebuttal, DRA still opposes it. PG&E provides training curriculum expenses in a different format than by MWC. This makes it unnecessarily difficult to track expenses associated with training. With no reliable historical data to evaluate, there is no way to ensure that a duplication of efforts and expenses does not occur or assess why PG&E is requesting additional funding for a routine, ongoing expense.

DRA considers training curriculum expenses to be routine and ongoing because PG&E is constantly updating and revising old courses, as well as implementing new courses. PG&E provided a list of PG&E's training courses from 2007-2012 and the dates that each course was last delivered.[974] Several courses were last delivered prior to 2012 while many are continuing, thereby illustrating that there are embedded costs from ongoing, obsolete, and completed courses. PG&E provided no evidence or explanation as to why current embedded costs for these programs are not sufficient to cover training of PG&E's work force. PG&E is responsible for reallocating ratepayer funds from outdated and ongoing courses into the newly proposed course programs and making appropriate downward adjustments to the MWCs. PG&E did not adjust existing MWCs where historical training expenses are recorded. Therefore, DRA recommends that the Commission reject PG&E's request for $4.135 million.[975]

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[974] Ex. 73 (DRA-5), p. 71 citing DRA-150-EJ1 question 1

[975] Ex. DRA-73 (DRA-5), p. 71.

4.20.1.2 MWC AB -- Support

PG&E records expenses for miscellaneous support activities in Major Work Category (MWC) AB such as membership to the Edison Electric Institute (EEI). PG&E also uses MWC AB to record a credit representing PG&E productivity improvements. DRA recommends in Exhibit DRA-2 (Summary of Earnings) that PG&E's forecast of $(10.191) million for productivity improvements be accepted.

4.20.2 Capital Expenditures

PG&E requests $9.082 million cumulative capital expenditure for 2012 through 2014 for MWC 78.[976] DRA recommends a cumulative capital expenditure of $4.051 million for 2012, 2013 and 2014

PG&E's requested increase is for additional security for five locations starting in 2013 and ten locations starting in 2015.[977] PG&E has approximately 20,000 employees who provide gas and electric service to approximately 15 million people throughout a 70,000 square mile service territory. Every year PG&E provides building upgrades throughout its service territory. These costs are normal and continuous and build into PG&E's base costs. These costs are located in every department of PG&E at all levels and cannot be separated. Therefore, DRA recommends no additional funding for PG&E's electric distribution building – additional security.

Escalation

DRA made modifications to PG&E's escalation worpkapers by replacing PG&E's proposed Manage Buildings 2013 and 2014 capital expenditures with DRA's recommended 2013 and 2014 recommended Manage Buildings Capital expenditures for MWC 78.[978]

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[976] Ex. 55 (PG&E-19), p. 20-9.

[977] Ex. 76 (DRA-8), p. 52.

[978] Ex. 76 (DRA-8), p. 53.

5 CUSTOMER CARE

5.1 Policy and Introduction

5.1.1 Policy

In this GRC, PG&E's Senior Vice President and Chief Customer Officer says that her objective is to "…focus the organization on providing customer satisfaction at every interaction, while delivering cost-effective products and programs to help our customers manage their energy use." She says she is also "…. keenly focused" on preparing PG&E to serve customers in the future with upgraded technology and process improvements as well as effective and informative communications.[979]

In PG&E's last GRC, PG&E said it was "…focused on providing our customers with safe and reliable electric and gas service" and that, "[d]elighting our customers is the first goal for PG&E."[980]

Though the words change slightly, the pattern is the same. PG&E seeks substantial increases to "focus" its attention on Customer Care, and then spends the funding elsewhere. In some instances, PG&E is seeking rate increases for exactly the same Customer Care projects it swore were essential in the last GRC, but then never carried out.[981]

Given this track record, DRA attempted to review PG&E's Customer Care forecasts as presented in this GRC, but also in light of representations made in previous GRCs, and PG&E's actual spending in the intervening years. PG&E's presentation in this case has not made that task easy.

PG&E changed the way it organized Customer Care Departments, Major Work Categories, and Chapters between the last GRC and this one. PG&E's testimony in this GRC often does not provide recorded 2011 expenses for specific activities where PG&E requests

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[979] Ex. 22 (PG&E-5), p. 1-1.

[980] Ex. 215, p. 1-1.

[981] See, Ex.81 (DRA-13), p. 40, lines 13-18 (Local Office Staffing), p. 44-45 (Local Office Improvements), p. 74-75 (Meter Tampering), p. 106, line 7 (Account Services), p. 114, line 12 (Ongoing support of PDP program, p. 119, line 8 (Customer Insight and Strategy Department).

incremental increases for 2014. Rather, PG&E provides 2011 expenses by Chapter and Major Work Category to forecast 2014.[982]

For example, PG&Es first request in testimony for an increase of $1.6 million for "Training and Communication of CSRs"[983] does not provide 2011 recorded expenses for such activities. DRA requested "average monthly training and training costs (in nominal dollars) for CSRs and team leads for the years 2007-2011 and forecasts for 2012-2014,"[984] PG&E provided only ongoing training, and included Smart Meter related training, which was apparently charged to the non-GRC balancing account, Major Work Category IG. PG&E's choice to narrow the scope of DRA's question, and then relate the question to non-GRC activities, was a reoccurring theme during discovery. This wasted DRA's time, as well as PG&E's, and hindered the evaluation of PG&E's requests.

Below, DRA presents its recommendations and discusses the areas of Customer Care where DRA disputes PG&E's forecasts.

5.1.2 Introduction and Summary

When PG&E filed its Application in this GRC, it was forecasting Customer Care expenses for 2014 of $461.9 million. PG&E later amended that to $454.6 million.[985] In 2011, PG&E's actual recorded costs for Customer Care expenses were $310.41 million. This amount does not include meter reading expenses which were recorded in a balancing account throughout the 2011 GRC cycle.[986]

For Customer Care expenses, DRA recommends an overall adjustment of $155.5 million from PG&E's expense forecast, or total TY 2014 Customer Care expense forecast of $299.086 million.[987]

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[982] Ex. 81 (DRA-13), p. 5. *See, e.g.*, Office Services, described below in Section 5.3 of this Opening Brief.

[983] Ex 22 (PG&E-5), p. 2-9.

[984] Ex. 81 (DRA-13), p. 6, citing PG&E's response to DRA_014-Q08.

[985] Ex. 57 (PG&E-20), p. 2.

[986] Ex. 22 (PG&E-5), p. 1-3, 1-18, Table 1-3, column "2011" Recorded, line 10 minus line 6.

[987] Ex. 110 (DRA Errata), p. 3.

In this Application, PG&E's Customer Care capital expenditure forecasts were $134.1 million in 2012, $142.6 million in 2013, $190.1 million in 2014, $166.8 million in 2015, and $161.7 million in 2016. In 2011, PG&E's recorded capital expenditures were $113.9 million.[988]

For Customer Care capital expenditures DRA recommends $131.062 million in 2012, $118.773 million in 2013, and $120.633 million in 2014.[989]

PG&E's O&M activities and costs are grouped with similar types of work into a Major Work Category (MWC). PG&E's forecasts for MWC expenses are expressed in SAP nominal dollars. SAP dollars include certain labor-driven adders such as employee benefits and payroll taxes that are charged to separate Federal Energy Regulatory Commission (FERC) accounts. DRA's recommendations are made by MWC and SAP nominal dollars which are then translated into the appropriate FERC accounts through the Results of Operations (RO) model.

In general, PG&E's estimating method to forecast most of the TY 2014 Customer Care expenses was to use 2011 recorded expenses as the base year (after removing one-time and non-recurring costs), add planned or anticipated cost increases (including labor escalation), and deduct planned 2012 through 2014 cost-savings initiatives. PG&E used this method to forecast TY 2014 expenses for Customer Inquiry Assistance,[990] Office Services,[991] Meter to Cash,[992] Customer Energy Solutions,[993] and Metering.[994]

For Information Technology Projects, PG&E proposed individual projects and forecasts expenses (and capital expenditures) with PG&E's Concept Estimating Tool.[995]

For capital expenditures for 2012, 2013, and 2014, PG&E method was predominately project -based.[996]

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[988] Ex. 22 (PG&E-5), p. 1-4.

[989] Ex. 110 (DRA Errata), p. 4.

[990] Ex. 22 (PG&E-5), p. 2-21.

[991] Ex. 22 (PG&E-5), p. 3-14.

[992] Ex. 22 (PG&E-5), p. 4-48.

[993] Ex. 22 (PG&E-5), p. 7-42.

[994] Ex. 22 (PG&E-5), p. 5-26.

[995] Ex. 22 (PG&E-5), p. 9-14.

[996] *See* Ex. 22, (PG&E-5), pp. 2-20 (Customer Inquiry Assistance), 3-14 – 3-15 (Office Services), p. 4-37 (Meter to Cash), p. 7-43 (Customer Energy Solutions), but see p. 5-26 (Metering) and p. 9-14

5.2 Customer Inquiry Assistance

5.2.1 Expense

PG&E's Customer Inquiry Assistance Program consists of PG&E's five contact centers, the Workforce Management (WFM) group, the Escalated Complaints Management (ECM) group, and the Customer Care Compliance group.[997] PG&E says that its Customer Inquiry Assistance Program is "…the Company's primary method of direct communication with its customers enabling PG&E to provide information to customers, listen to customer feedback, respond to customer requests, and improve public safety communications.[998]

For 2014, PG&E requests $119.1 million in expenses, reduced from PG&E's original forecast of $125.2 million in expenses associated with Customer Inquiry Assistance. PG&E's 2011 recorded expenses were $102.3 million, an expense increase of $16.8 million. DRA recommends $96.4 million for 2014, $5.8 below 2011 recorded expenses.[999] This is an adjustment of $22.7 million to PG&E's request.[1000]

The forecasts in dispute are discussed below.

5.2.1.1 Training and Communication for Customer Service Representatives (CSRs)

For 2014, PG&E forecasts an incremental increase of $1.6 million over 2011 recorded expenses for increased training for Customer Service Representatives (CSRs.)[1001] DRA recommends no incremental ratepayer funding for increased training in 2014.

PG&E states that there has been increasing complexity of calls requiring more training for CSRs. Drivers that can increase call complexity include "…new tariffs, the significant increase in customer information associated with the implementation of Smart Meter devices, changes to credit policies that require additional information, topics such as community choice

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(Information Technology).

[997] Costs associated with customer payment and non-payment transactions handled at PG&E's 75 local offices are discussed below, in Section 5.3, Office Services.

[998] Ex. 22 (PG&E-5), p. 2-1, lines 25-28.

[999] *See* Ex. 103 (DRA-13 workpapers vol. 1), p. WP 2-4.

[1000] Ex. 81 (DRA-13), p. 13.

[1001] Ex. 22 (PG&E-5), p. 2-9, Ex. 23 (PG&E-5workpapers), p. 2-32.

aggregation and other complex topics."[1002] PG&E's cost estimate is based on implementing training for 1,020 CSRs.[1003] PG&E's 2011 yearly average Active Bargaining Unit headcount was 910.[1004] PG&E identified increases in training for new hires as contributing to the increased total labor costs.[1005] PG&E states that "The two additional hours of training for CSRs in 2014 is intended to improve the customer experience and positively contribute to PG&E's repeat call reduction initiative, which is forecasted to save $2M."[1006]

In 2010, the Boston Consulting Group (BCG) evaluated PG&E's customer contact center performances, and identified different approaches to training that could result in overall improvement without requiring increased ratepayer funding. The BCG issued a report which noted the following potential initiatives:[1007]

- Provide additional soft skill training and increase consistency across agents
- Deliver training in needs-based model
- Provide additional facilitated ongoing training for CSRs
- Shift from initial training or self-paced training and determine whether current level of multi-skilling is optimal
- Develop and utilize training effectiveness measures
- Ingrain common understanding of the perfect call across teams and levels
- Build learning's from analysis of top-performing agents into training curriculum
- Upgrade staffing system capabilities to allow real time training scheduling during periods of low demand (i.e. removing agents from phone for online training modules delivered on desktop)

The initiatives BCG identified could be implemented with a shift in procedures and without incremental funding. BCG states that PG&E's training is "front loaded for new hires."[1008] BCG's initiative to "develop and utilize training effectiveness measures" highlights

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[1002] Ex. 22 (PG&E-5), p. 2-9, lines 9-13.

[1003] Ex. 23 (PG&E-5 workpapers), p. WP 2-33.

[1004] Ex. 81 (DRA-13), p. 16, citing PG&E's response to DRA_014-11.

[1005] Ex. 81 (DRA-13), p. 16 citing PG&E's response to DRA_014-05.

[1006] Ex. 81 (DRA-13), p. 16 citing PG&E's response to DRA_014-08.

[1007] Ex. 81 (DRA-13), p. 16, citing PG&E's response to DRA_14-Q13, see Atch01, p. 29, 30.

[1008] Ex. 81 (DRA-13), p. 17, citing PG&E's response to DRA_14-Q13 see Atch01, p. 13.

the notion that more refined training could be more effective than simply increasing the hours of training.

BCG recommended that PG&E "deliver training in needs-based model."[1009] This is a process change which recognizes that training is not "one size fits all" but rather driven by the needs of the employee. A needs based model could reduce the amount of training hours by shifting training hours to those employees who need more, from those who need less training to be effective.

In Rebuttal, PG&E says that "DRA's recommendation is based on the false assumption that PG&E does not use any of the training practices identified in the BCG Report," and then goes on to say that PG&E "… does utilize to some extent the majority of the training initiatives noted in the BCG report."[1010] PG&E may indeed be using some of the training initiatives, but it does not appear to be using them very effectively.

The BCG report identified that PG&E's initial training was 2.6 times comparable benchmarks and ongoing training was 0.6 times comparable benchmarks.[1011] In Rebuttal, PG&E argues that the industries BCG used as comparable benchmarks, including Insurance, Finance, Healthcare, Technology, Media and Telecommunications, are not really comparable at all. According to PG&E, "none of the industries sampled are regulated utilities, and thus the complexity of the programs that PG&E CSRs need training on are not necessarily inherent in the call centers of the sampled benchmarks."[1012] Evidently, the Boston Consulting Group considered that a Customer Service Representative handling calls about insurance, health care, finance or technology, media and telecommunications does indeed have to be trained on complex customer programs or regulatory requirements and common sense supports that.

DRA continues to recommend no incremental funding for CSR training. DRA recommends that instead of constantly asking for rate increases, PG&E find ways to use embedded training money more effectively.

[1009] Ex. 81 (DRA-13), p. 18, citing PG&E's response to DRA_014-Q13 see Atch01, p. 29.

[1010] Ex. 57 (PG&E-20), p. 2-8.

[1011] Ex. 81 (DRA-13), p. 17, citing PG&E's response to DRA_14-Q13 see Atch01, p. 74.

[1012] Ex. 57 (PG&E-20), p. 2-10.

5.2.1.2 Customer Access Improvements

For 2014, PG&E forecasts an incremental increase of $5.9 million over 2011 recorded expenses for Major Work Category DK –Manage Customer Inquiries.[1013] DRA recommends no incremental ratepayer funding in 2014 for this function.[1014]

PG&E proposes lowering the "2011 Average Speed of Answer (ASA) of 59 seconds to the first quartile performance target of 28 seconds."[1015] To do so, PG&E includes in its forecast the costs of "approximately 68 additional CSRs."[1016]

In response to a data request, PG&E stated that its actual ASA in 2011 was 32 seconds, a second quartile performance in benchmarking, and 27 seconds faster than the 2011 utility average of 59 seconds.[1017] In its testimony, PG&E does not distinguish between blended ASA, which includes interactive voice response (IVR) and customer service representative (CSR) ASA. In PG&E's responses to DRA data requests, PG&E provided "blended" Average Speed of Answer.

In Rebuttal, PG&E says that DRA's recommendation "…is primarily based on DRA's flawed comparison of live CSR ASA and Blended (live CSR plus automated system) ASA."[1018] According to PG&E, adding 68 new employees at an expense of $5.9 million will result in a 31-scond improvement in Average Speed of Answer for calls answered by a live Customer Service Representative.

That does not change the fact that the Commission has not adopted a requirement for speed of answer by a live Customer Service Representative. Instead, the Commission has adopted a Telephone Service Level (TSL) standard requiring that PG&E answer 80 percent of calls within 20 seconds."[1019] PG&E has been in compliance with the Commissions standard TSL

[1013] Ex. 22 (PG&E-5), p. 2-9.

[1014] Ex. 81 (DRA-13), p. 18.

[1015] Ex. 22 (PG&E-5), p. 2-9, lines 26-27.

[1016] Ex. 22 (PG&E-5), p. 2-9, line 29.

[1017] Ex. 81 (DRA-13), p. 19 citing PG&E's response to DRA_232_01.

[1018] Ex. 57 (PG&E-20), p. 2-4.

[1019] Ex. 81 (DRA-13), p. 19 citing PG&E's response to DRA_014-Q09.

since 2007, and has improved its percentage of total calls handled within 20 seconds to 84% in 2011 and 2012.[1020]

In response to DRA discovery requests regarding historical benchmarking of customer service representative ASA, PG&E said that "… the results of the Boston Consulting Group (BCG) … was a stand-alone study that provided a snapshot of PG&E's performance compared to the industry averages, including Agent to Supervisor ratios and Customer Service Representative (CSR) Average Speed of Answer (ASA)."[1021] This statement seems to imply that PG&E has not historically tracked CSR ASA, yet the request for $5.9 million for the addition of 68 CSRs is specifically for CSR ASA.

In any event, PG&E already has the capability to use Virtual Hold Technology (VHT).[1022] If the customer chooses to use it, this feature dramatically reduces the time a customer actually spends on the phone waiting. Also, the implementation of the Contact Center Refresh project, forecasted by PG&E to be operational at the end of 2013,[1023] will allow PG&E to better manage the customer queue and increase "…operational efficiencies and Service Level ("SL") attainment due to increases in IVR resolution rate."[1024] The increase in interactive voice response (IVR) systems will drive a reduction in CSR handled calls allowing the 2011 level of staffing to answer calls more quickly.

DRA continues to recommend zero incremental funding for PG&E's request for an additional 68 CSRs. At its current staffing level, PG&E is well above the Commission adopted Telephone Service level of 80%, and should be expected to remain at that level or higher with the completion of the Contact Center Refresh project[1025] at the end of the year.

[1020] Ex. 81 (DRA-13), p. 19, Table 13-16.

[1021] Ex. 103 (DRA-13 workpapers, vol. 1), (PG&E's response to DRA-271, Q. 1.)

[1022] VHT is a call-back function that holds caller's place in queue.

[1023] Ex. 81 (DRA-13), p. 20 citing PG&E's response to DRA_171-Q07.

[1024] Ex. 81 (DRA-13), p. 20 citing PG&E's response to DRA_125-Q21 p. 2.

[1025] The Contact Center Refresh project is described in more detail below in Section 5.2.1.4. in this Brief.

5.2.1.3 Increased CSR Supervision and Support

For 2014, PG&E forecasts an incremental increase of $1.8 million over 2011 recorded expenses for increased CSR supervision and support.[1026] DRA recommends no incremental ratepayer funding in 2014 for this proposed supervisor- to- employee- ratio cost increase.

PG&E forecasts 16 additional supervisors from 2011 to 2014. PG&E says that "the added leadership will provide increased coaching and counseling support for CSRs, which will expand CSRs soft skills, enhance employee engagement, and improve CSRs interaction with customers."[1027] PG&E says that the added leadership will improve CSR interaction with customers which "…will help increase customer satisfaction."[1028] PG&E has not, however, forecasted any ratepayer benefits for this "…additional leadership for CSRs."[1029]

PG&E improved the "agent (FTE) to supervisor" ratio from 2007 to 2011.[1030] Then in 2012 PG&E added 100 FTE CSRs, Utility Clerks, and smart energy line (SEL) representatives, yet added zero supervisors.[1031] From data provided by PG&E it appears that "team leads" provide a leadership role. Later in the BCG report "team leads" are referred to as "leadership."[1032] (In the data presented by PG&E team leads are captured as FTEs supervised). PG&E later clarified that it uses the titles "Team Lead" and "Supervisor" interchangeably in this context.[1033]

If PG&E is truly committed to "continuously innovating to improve [PG&E's] customer service[1034] then it should have acted on this idea in 2011 or 2012, rather than waiting until TY 2014 to act. PG&E's inaction on increasing supervision for CSRs to date, suggests that even PG&E does not consider it to be critical and necessary to providing safe and reliable customer service.

[1026] Ex. 22 (PG&E-5), p. 2-10.

[1027] Ex. 22 (PG&E-5), p. 2-10, lines 13-17.

[1028] Ex. 22 (PG&E-5), p. 2-10.

[1029] Ex.81 (DRA-13), p. 21 citing PG&E's response to DRA_014-Q10.

[1030] Ex. 81 (DRA-13), p. 21.

[1031] Ex.81 (DRA-13), p. 21 citing PG&E's response to DRA_125-Q07Atch01.

[1032] Ex.81 (DRA-13), p. 21 citing PG&E's response to DRA_014-Q13 see Atch01.

[1033] Ex. 57 (PG&E 20), p. 2-15.

[1034] Ex. 22 (PG&E-5), p. 1-1, lines 12-13.

In Rebuttal, PG&E says that "PG&E was unable to add supervisors in 2012 due to budgetary constraints and competing priorities."[1035] These are budgetary constraints of PG&E's own making. The revenue requirement adopted for PG&E for the years 2011, 2012 and 2013 resulted when the Commission adopted a Settlement in PG&E's last GRC which PG&E willingly signed. If PG&E elected to use that revenue requirement to pay out Short Term Incentive Program bonuses in 2012, rather than add supervisors in its Customer Care organization, that is no reason for PG&E's ratepayers to make up the difference in 2014.

In any event, the implementation of the Contact Center Refresh PG&E will result in "improved caller authentication and improved call targeting"[1036] which in turn will result in calls being handled more efficiently, resulting in fewer employees. For these reasons DRA recommends zero ratepayer funding for additional supervisor positions for 2014.

5.2.1.4 Average Handle Time Increases

For 2014, PG&E forecasts an $11.2 million increase beyond 2011 recorded expenses.[1037] DRA recommends no incremental ratepayer funding for PG&E's forecasted average handle time increases (AHT).

PG&E says that AHT is trending up and that PG&E "expects AHT to continue to increase in 2014 and beyond."[1038] According to PG&E, AHT has increased an average of 4.1% annually and that, to maintain the current service levels will require $11.2 million incremental funding for 2014 or approximately 129 incremental CSRs (Full Time Equivalent). DRA recommends that the Commission allocate no additional ratepayer funding for this proposal.

Several historical factors should be considered in order to put PG&E's request in context. First, when looking at historical AHT data, there is no direct correlation between total yearly recorded expenses and total yearly CSR labor costs.[1039] CSR costs, and especially Total Customer Inquiry expenses, are not dependent on the "minutes CSRs handle calls."[1040] PG&E

[1035] Ex. 57 (PG&E 20), p. 2-13.

[1036] Ex. 23 (PG&E-5 workpapers), WP 9-104.

[1037] Ex. 22 (PG&E-5), p. 2-12.

[1038] Ex. 22 (PG&E-5), p. 2-11, lines 9-10.

[1039] 19 RT 2105, lines 10-15, Phillips/PG&E.

[1040] Ex. 81 (DRA-13), p. 22: Minutes CSRs handle calls is the amount of time customer service

forecasted AHT to be at 337[1041] seconds in 2012, yet the actual recorded 2012 AHT was 332[1042] seconds. Further, PG&E realized a reduction of approximately 120,000[1043] CSR handled calls in 2012 compared to 2011. Although AHT in 2012 increased to 332[1044] seconds over the average 324 seconds in 2011,[1045] this increase was at a lower rate than PG&E's forecast of 337.[1046] Moreover, Actual Total CSR Labor Costs decreased from 2011 to 2012,[1047] strengthening the point that AHT and Actual CSR Total Labor costs are not directly correlated.

Second, PG&E is currently finalizing a major information technology (IT) project[1048] which will replace outdated software. According to PG&E, eight different outdated software programs currently in use will be replaced by the Contact Center Refresh project by the end of the fourth quarter, 2013.[1049] PG&E's total forecasted cost for the Contact Center Refresh Project is approximately $20.5 million.

One of the non-cost benefits of the Contact Center Refresh project, according to PG&E is "Average Handle Time ("AHT") reduction due to high authentication rate and persistence of attached data during transfers."[1050] PG&E did not quantify an associated cost benefit for AHT with this statement, but acknowledges that some actual cost benefits for AHT will be realized in 2014 from new functionalities associated with the Contact Center Refresh project.[1051] In hearings, DRA asked PG&E if there could be additional reductions in the average handle time due to the Contact Center Refresh other than PG&E's quantified soft phone savings. PG&E's

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representatives (CSRs) are on the phone with customers and is calculated by taking total yearly CSR handled calls * yearly average handle time (AHT) divided by 60 to convert AHT (which is presented in seconds) into minutes.

[1041] Ex. 22 (PG&E-5), p. 2-11.

[1042] Ex. 81 (DRA-13), p. 25, citing PG&E's response to DRA_125Q03 see Atch01, WP 2-19.

[1043] Ex. 81 (DRA-13), p. 25, citing PG&E's response to DRA_125-Q03 see Atch01, WP 2-15.

[1044] Ex. 81 (DRA-13), p. 25, citing PG&E's response to DRA_125-Q03 see Atch01 WP 2-19.

[1045] Ex. 23 (PG&E-5 workpapers), p. WP 2-19.

[1046] Ex. 22 (PG&E-5), p. 2-11, Table 2-3.

[1047] Ex. 81 (DRA-13), p. 25, citing PG&E's response to DRA_125-Q03 see Atch01 WP 2-15.

[1048] Ex. 81 (DRA-13), p. 25, citing PG&E's response to DRA_125-Q07.

[1049] Ex. 81 (DRA-13), pp. 25, 26, Table 13-20.

[1050] Ex. 23 (PG&E-5 workpapers), WP 9-105 see (bullet 4).

[1051] Ex. 23 (PG&E-5 workpapers), p. WP, pp. 9-104-9-105.

witness responded, "I don't know the answer to that. We are still in the process of doing Contact Center Refresh. So I don't have any experience with what those other benefits might be or reductions in AHT."[1052]

The evidence does not support PG&E's inherent assumption that AHT will continue to increase at the yearly 4.1%.[1053] Given the implementation of the Contact Center Refresh Project (at the considerable investment of $20.5 million) and the weak correlation between Actual Recorded CSR Costs, Actual Recorded Customer Inquiry Assistance Costs and minutes CRSs handling calls, DRA continues to recommend no ratepayer funding for PG&E's forecasted increase in AHT.

5.2.1.5 Repeat Call Reduction

For 2014, PG&E forecasts an incremental decrease of $2.0 million to 2011 recorded expenses in MWC DK due to repeat call reductions. DRA recommends a $1.7 million incremental decrease in 2014 for repeat call reductions.

DRA's forecast is based on the assumption of a 2% reduction in the number of repeat calls in 2014. This is likely a conservative estimate given the increase in capabilities through the Contact Center Refresh.[1054]

5.2.1.6 Contact Center Staffing and Facilities

For 2014, PG&E requests an incremental increase of $1.2 million over 2011 recorded expenses for the expansion of Contact Center facilities.[1055] DRA recommends zero incremental expenses for the expansion of the contact center facilities in 2014.

PG&E is requesting funding to expand its Sacramento and Fresno Contact Centers by 135 seats each in 2014 at an estimated $1.2 million in expenses and $15.5 million in capital for 2014. Based on DRA's recommendation regarding PG&E's proposed capital expenditure, which appears below in Section 5.2.2. in this Opening Brief, DRA recommends reducing PG&E's 2014 expense forecast by $1.2 million.

[1052] 21 RT 2106-2107, Phillips/ PG&E.

[1053] Ex. 23 (PG&E-5 workpapers), p. WP 2-20.

[1054] Ex. 23 (PG&E-5 workpapers) p. WP 2-3.

[1055] Ex. 22 (PG&E-5), p. 2-16.

5.2.2 Capital Expenditures

PG&E requests funding to expand its Sacramento and Fresno Contact Centers by 135 seats each in 2014 at an estimated $1.2 million in expenses and $15.5 million in capital expenditures in 2014.[1056] PG&E states three reasons for the expansion of Sacramento and Fresno Contact Centers: (1) additional staffing increase of 200 net positions for 2014; (2) Increased safety concerns in the Stockton Contact Center area; and (3) Expensive/limited parking availability in the San Jose Contact Center area.[1057]

PG&E states that items 2 and 3 "have led to a reduction of operation hours both in Stockton and San Jose Contact Centers and increased employee attrition."[1058]

As discussed elsewhere, DRA opposes PG&E's requested increase in employees. As to reasons (2) and (3), DRA notes that PG&E just completed an expansion of the Sacramento Contact Center of nearly 125 CSR workstations in 2011.[1059] During a tour of that Sacramento Contact Center in 2012, PG&E told DRA that CSRs share desks and have several different shifts throughout the day. Since each employee does not necessarily have his or her own desk, PG&E should need no more than the number of desks required to respond to customer calls at peak times. According to a handout PG&E provided DRA during its tour, on October 4, 2012, PG&E's planned call center staffing for peak time was 490 Customer Service Representatives.[1060]

The Contact Refresh Project is expected to provide "Agent flexibility – Laying the foundation for future at home agent capability (Split days off-occupancy, lower attrition, reduce training, split shifts-occupancy and lower facility costs)."[1061] Due to the current number of workstations already available, and the fact that PG&E did not quantify the benefits, (if any) associated with the expansion of 270 CSR workstations. DRA recommends zero capital funding

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[1056] Ex. 22 (PG&E-5), p. 2-16.

[1057] Ex. 22 (PG&E-5), p. 2-15, lines 25-29.

[1058] Ex. 22 (PG&E-5), p. 2-15, lines 27-29.

[1059] Ex. 23 (PG&E-5 workpapers), WP 2-45, note 1 (bottom of page).

[1060] Ex. 218; 19 RT 2117, Phillips/ PG&E.

[1061] Ex. 81, p. 36, citing PG&E's response to DRA_125-Q21.

in 2014 for expansions of Customer Contact Centers, DRA's recommendation also reduces PG&E's 2014 expense forecast by $1.2 million, as previously discussed.[1062]

5.3 Office Services

PG&E seeks ratepayer funding of $34.2 million for Office Services expenses. This request for 2014 expenses is 18% higher than 2011 recorded expenses.[1063] PG&E says its forecasted increases in costs are due to labor escalation, additional customer service representatives and building improvements. DRA recommends TY 2014 Office Service expenses of $31.6 million, an adjustment of $2.6 million to PG&E's forecast.

For Office Services capital expenditures in Major Work Category 21 – Miscellaneous Capital, and Major Work Category 22—Maintain Buildings, PG&E requests $0.2 million in 2012, $0 million in 2013 and $4.0 million in 2014. DRA recommends that PG&E's 2014 request for ratepayer funding of $4.0 million in 2014 for Major Work Category 22 be rejected.[1064]

5.3.1 Expense

PG&E's Office Services Program manages the 75 local offices operated by PG&E employees. Expenses are for management of customer payments and, to a lesser degree, non-payment transactions.

PG&E made a number of changes to the Major Work Categories for Office Services since the 2011 GRC. Office Services was previously covered under Major Work Category FT. In the 2014 GRC, Office Services costs are reflected in Major Work Categories DK -- Manage Customer Inquiries, EZ -- Manage Various Customer Care Processes, and IU -- Collect Revenue.[1065] PG&E's testimony does not delineate forecasted incremental increases in expenses by Major Work Category, but rather allocates them between Major Work Categories, DK, EZ

[1062] Ex. 81 (DRA-13), p. 36.

[1063] Ex. 22 (PG&E-5), p. 3-1, lines 18-22.

[1064] Ex. 81 (DRA-13), p. 45.

[1065] Ex. 22 (PG&E-5), p. 3-3, footnote 2.

and IU.[1066] Therefore, DRA will address PG&E's increases from a global perspective and allocate adjustments based on percentage of 2011 recorded expenses.

5.3.1.1 Local Offices Customer Service

For 2014, PG&E requests an increase of $1.1 million beyond 2011 recorded expenses for the addition of 10 customer service representatives to staff the 75 local offices.[1067] DRA recommends zero ratepayer funding for this proposed increase.[1068]

There has been a decline in staffing in the local offices in the years 2007-2011. PG&E says it needs an increase in staffing to reduce customer wait times. According to PG&E, customers are waiting at certain local offices to speak to a customer service representative an average of 8 minutes 35 seconds to 10 minutes 16 seconds on selected days between July and December 2011.[1069] DRA requested information on staffing levels for days presented in PG&E's workpapers,[1070] but PG&E provided no evidence to show that offices were, in fact, fully staffed on the days presented in workpapers.[1071] DRA recommends the Commission not rely on PG&E's data.

In PG&E's prior GRC, PG&E requested funding for increases for non-payment transactions. PG&E stressed "this increase directly affects local offices because, historically, 60 percent of customers looking to restore their power have used the local offices to make their payment. To maintain existing service levels, PG&E estimates that 11 new positions will be required in 2011 to address the increase in walk-in traffic. PG&E estimates the cost at $0.98 million."[1072]

According to PG&E's recorded staffing levels, however, PG&E has actually reduced staffing at PG&E's local 75 offices from 2008-2011 by 26 positions, and the number of payment

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[1066] Ex. 23 (PG&E-5), p. WP 3-9.

[1067] Ex. 22 (PG&E-5), p. 3-7.

[1068] Ex. 81 (DRA-13), p. 39.

[1069] Ex. 23 (PG&E-5), p. WPs 5-16 to 5-17.

[1070] Ex. 81 (DRA-13), p. 40 citing PG&E's responses to DRA_15-Q16 and DRA_126-Q01.

[1071] Ex. 23 (PG&E-5 workpapers), p. WP 3-16 – 3-17.

[1072] Ex. 81 (DRA-13), p. 40, citing A. 09-12-020, Ex. PG&E-4, p. 3-6, 18-22.

transactions recorded at the local offices decreased by approximately 700,000 between 2007 and 2011.[1073] PG&E does not track the number of non-payment transactions.[1074]

In Rebuttal, PG&E says the "reduction in staffing resources from 2008 – 2011 was due to a reprioritization of funding from Customer Care to other operational lines of business which ultimately translated to less resources and CSRs available at local offices."[1075] PG&E then cites to its own testimony in its TY 2011 GRC which says that in 2008 through 2011 PG&E also "re-prioritized" funding away from Customer Care."[1076]

PG&E's arguments notwithstanding, the evidence shows that the payment behavior of PG&E's customers is changing significantly. In addition to the expansion of electronic payment options for customers, PG&E also increased payment kiosks in its local 75 offices for customers to use. PG&E maintained 20 payment kiosks at the end of 2011 and added 10 more for a total of 30 by the end of 2012,[1077] leading to an increase of kiosk payments of approximately 70,000 from 2011 to 2012.

But even without the evidence of increased payment options for customers, and their increased use by customers, PG&E's past practices of asking for funding for Customer Care staffing, and then diverting the funding to other lines of business should give the Commission pause. There is absolutely no assurance that PG&E will use ratepayer funding authorized for Customer Service Representatives at local offices for that purpose. DRA continues to recommend no incremental funding for the addition of customer service representatives in its local 75 offices.[1078]

5.3.1.2 Local Office Operational Reviews

For 2014, PG&E requests an increase of $0.1 million over 2011 recorded expenses for an additional auditor in order to audit all of PG&E's 75 local offices on an annual basis.[1079] DRA

[1073] Ex. 81 (DRA-13), p. 40.

[1074] Ex. 81, (DRA-13) p. 41 citing PG&E's response to DRA_015_Q13.

[1075] Ex. 57 (PG&E-20), p. 3-4.

[1076] Ex. 57 (PG&E-20), p. 3-4.

[1077] Ex. 81 (DRA-13), p. 42, citing PG&E's response to DRA_151-Q22.

[1078] Ex. 81 (DRA-13), p. 42.

[1079] Ex. 22 (PG&E-5), p. 3-9, lines 1-3.

recommends an incremental increase over 2011 expenses of $0.06 million to support a part-time position in 2014; this is an adjustment of $0.06 million to PG&E's request. PG&E was able to audit 69% of the 75 local offices in 2011 with one auditor and providing PG&E with an additional part-time position should allow PG&E to audit 100% of the 75 local offices.[1080]

5.3.1.3 Local Office Facilities

For 2014, PG&E requests $1.4 million in incremental expenses beyond 2011 recorded for expenses associated with requested capital expenditures. DRA recommends no incremental ratepayer funding for 2014 beyond 2011 recorded as explained in the capital section below.

5.3.2 Capital Expenditures

PG&E requests capital expenditures of $0.2 million in 2012, $0 in 2013 $4.0 million in 2014, Major Work Category 21 --Miscellaneous Capital and Major Work Category 22 -- Maintain Buildings.

5.3.2.1 MWC 22 – Maintain Buildings

PG&E says that some of its 75 local offices are in need of major upgrades including remodeling, relocations, workstations, and signage.[1081]

PG&E states that it has identified six locations that require remodeling and six that require relocation to improve the Company's ability to serve customers.[1082] PG&E requests incremental expenses beyond 2011 recorded of $0.4 million in 2014, and a total of $2.5 million in capital expenditures from 2014-2016, $1.0 in 2014, $1.0 in 2015 and $0.5 in 2016.[1083] PG&E also requests funding over recorded 2011 levels for the installation of ergonomic workstations. For 2014, PG&E seeks $1.0 million in 2014, and a total of $7.7 million in capital expenditures from 2014-2016.[1084] Finally, PG&E requests capital expenditures for improved customer signage of $0.4 million in 2014, $0.4 million in 2015 and $0.5 million in 2016.[1085] DRA

[1080] Ex. 81 (DRA-13), p. 43.

[1081] Ex. 22 (PG&E-5) p. 3-9, lines 5-7.

[1082] Ex. 22 (PG&E-5), p 3-10 lines 7-10.

[1083] Ex. 22 (PG&E-5), p. 3-11, lines 5-7.

[1084] Ex. 22 (PG&E-5), p. 3-11, lines 30-32.

[1085] Ex. 22 (PG&E-5), p. 3-12 lines 7-9.

recommends no incremental ratepayer funding for any of PG&E's proposed Office Services capital projects in MWC 22 Maintain Buildings.

PG&E requested, in its TY 2011 GRC, funding through the Shared Services and Other Support Costs Exhibit, to:

> "…provide ergonomic front counter space furniture, improved lighting and new carpeting and paint as needed to create a consistent level of comfort and convenience for customers…As part of the initiative PG&E plans to relocate three Customer Service Offices to new locations because the existing space is inadequate or not cost effective to refurbish…PG&E's forecasts capital expenditures for CRE's Customer Office Refurbishment Initiative of $0.3 million in 2009, $0.2 million in 2010, $3.5 million in 2011, $3.3 million in 2012 and $4.2 million in 2013, and $1.5 million in expenses annually in 2011, 2012 and 2013."[1086]

The initiative also included signage costs of an average cost per site of approximately $30,000[1087] for every office except Colusa, Napa, Lakeport, and Stockton.[1088]

Since PG&E is seeking ratepayer funding in this 2014 GRC for work previously requested in its last GRC, Ordering Paragraph 43 of the Commission decision resolving that last GRC clearly applies:

> In its next general rate case, as part of its showing, Pacific Gas and Electric Company shall 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. Pacific Gas and Electric Company shall fully explain its reprioritization process, justify deferrals of specific activities and projects, and justify the implemented higher reprioritized activities and projects that were not identified in this general rate case. For activities and projects that were deferred and are now being re-requested, Pacific Gas and Electric Company shall fully explain why they are needed now when they were able to be deferred before.[1089]

In this GRC showing PG&E has not explained its reprioritization process, justified the deferral of upgrades or explained why the upgrades to the 75 local offices are needed now when

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[1086] Ex. 81 (DRA-13), p. 44, citing A. 09-12-020, Ex. PG&E-7, p. 6-35, lines 10-26.

[1087] Ex. 81 (DRA-13), p. 45, citing A. 09-12-020, Ex. PG&E-7, WP 6-133.

[1088] Ex. 81 (DRA-13), p. 45, citing A. 09-12-020, Ex. PG&E-7, WP 6-136.

[1089] D.11-05-018, Ordering Paragraph, 43; 2011 Cal. PUC LEXIS 275.

they could be deferred before. PG&E has embedded funding to support these projects if PG&E deems they are necessary for the 2014-2016 GRC cycle. For these reasons DRA recommends no incremental ratepayer funding for the refurbishment, relocation, installation of ergonomic workstation or improved customer signage as PG&E's local 75 offices.

5.3.2.2 MWC 21 – Miscellaneous Capital

5.4 Meter to Cash

For 2014, PG&E requests $136.4 million in expenses for its Meter to Cash programs. This is an increase of $25.6 million above 2011 recorded expenses of $110.9 million.[1090] DRA recommends a total 2014 Meter To Cash forecast of $107.9 million, $3 million below 2011 recorded expenses, an adjustment of $28.5 million to PG&E's request.

PG&E's Meter To Cash programs were previously known as Billing, Revenue and Credit. Meter to Cash includes pre-billing activities, issuance of customer bills and credit notices, post-billing maintenance of customer account information, customer payment processing, post-billing credit and collection activities, revenue reporting and customer-owned street light auditing and billing correction.[1091]

For 2014, PG&E seeks $9.011 million for capital expenditures. DRA recommends zero ratepayer dollars.[1092]

5.4.1 Expense

PG&E's Meter To Cash expense forecast includes pre-billing activities such as meter validation and exception processing bills and credit notices, post-billing maintenance of customer account information, customer payment processing, post-billing credit and collection operations activities, revenue reporting, and customer owned street light auditing and billing correction. PG&E's Meter To Cash activities are covered in Major Work Categories AR – Read Investigate Meters, IS – Bill Customers, IU – Collect Revenue, IT – Manage Credit, and EZ – Manage Various Customer Care Processes.[1093] DRA does not dispute PG&E's Meter to Cash

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[1090] Ex. 22 (PG&E-5), p. 4-2. PG&E revised the figures that appeared in its November 2012 testimony in the course of responding to DRA discovery.

[1091] Ex. 22 (PG&E-5), p. 4-1, lines 11-17.

[1092] Ex. 81 (DRA-13), p. 47.

[1093] Ex. 22 (PG&E-5), pp. 4-1 to 4-2.

expense forecasts for Major Work Categories AR and EZ. The other forecasts which DRA does dispute are discussed below.

5.4.1.1 MWC Is – Bill Customers

For 2014 expenses in Major Work Category IS, PG&E requests $89.5 million, which is an increase of $21.3 million above 2011 recorded expenses of $68.2 million. For 2014 for this Major Work Category, DRA recommends a total expense forecast of $67.1 million, which is $1.2 million below 2011 recorded expenses, and an adjustment of $22.4 million to PG&E's request.[1094]

Major Work Category IS includes pre-billing including data validation, processing and calculating customer bills including non-energy related services, maintenance of customer records within PG&E's billing system, Bill Print and Mail (BPM) operations, revenue reporting, cash management, and calculation of tax and franchise fee payments, field audit of customer owned streetlights and subsequent billing record corrections, and non-energy billing.[1095] In the following sections, DRA presents its review of activities covered by MWC IS for which PG&E seeks increases over 2011 recorded expenses.

Data Interval Processing

For 2014, PG&E requests an increase of $18.8 million for data processing and billing related work which will be offset by $5.2 million in Smart Meter benefits for a total increase of $13.7 million.[1096] For 2014, DRA forecasts a decrease of $5.2 million for data and billing related work below 2011 recorded expenses due to the fully realized benefits as identified in PG&E's AMI decision assumed by PG&E to be completed by 2014.[1097]

PG&E says that, in 2011, "…Billing Operation Support applied automated validation and editing (as required) to all Smart Meter interval data, and only manually worked data exceptions for those customers whose time-varying pricing tariff required interval values for billing."[1098]

[1094] Ex. 81 (DRA-13), p. 49.

[1095] Ex. 22 (PG&E-5), p. 4-9, lines 81-27.

[1096] Ex. 22 (PG&E-5), pages 4-17 to 4-18.

[1097] Ex. 81 (DRA-13), p. 50 citing D. 06-07-027, Table 1 "Stipulated AMI Project Costs," p. 29, line 7 and 14.

[1098] Ex. 22 (PG&E-5), p. 4-17, lines 11-15.

According to PG&E, in order to apply the same quality assurance and exception processing methods to all Smart Meter customers, daily exception processing would need to increase from approximately 500 transactions a day, to 50,000 per day, based on an electric meter population of 4.6 million meters.[1099]

To evaluate the validity of PG&E's claim that it needs incremental staffing to manually process such exceptions created through validating interval data, DRA reviewed past funding for such activities. In D.05-06-028, PG&E was authorized $85 million for "Interval billing system."[1100] In addition, PG&E was allocated $6.6 for "Customer exceptions processing."[1101] Based on the "PG&E Advanced Metering Assessment Report Commissioned by the CPUC," the Commission allocated funding for PG&E to upgrade its billing system. The upgrade was not fully implemented on the same schedule as Smart Meter deployment.

Structure, the consultant preparing the report, "…identified several items of partial or non-compliance related to industry best practices during the assessment."[1102] According to the Structure report further explains:

> The Meter Data Managements (MDMS) Interface best practice to correlate AMI meter events and alarms with Validation, Estimating and Editing (VEE) and Customer Information System (CIS) audits and checks for automated exception handling; and ii. The VEE Best Practice of MDMS must provide an on-line method, with workflow, resolving validation errors rather than reports. These lapses have created a situation where data required manual editing, causing cancel/re-bills and delayed processing of Customer data in a relatively small portion of the bills processed. The cancel/re-bills and delayed processing potentially increased the days within a billing cycle presented in Customer's bills, as reflected in a portion of the High Bill complaints, and furthered Customer perception that Smart Meters may not have been accurate.[1103]

This was Structure's finding for September 2010. Funding was provided in D.05-06-009 for the "interval billing system" and "customer exceptions processing" in order to resolve

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[1099] Ex. 22 (PG&E-5), p. 4-17, lines 21-26.

[1100] D.06-07-027, Table 1 "Stipulated AMI Project Costs," p. 29, line 7.

[1101] D.06-07-027, Table 1 "Stipulated AMI Project Costs," p. 29, line 14.

[1102] Ex. 81 (DRA-13), p. 51, citing PG&E Advanced Metering Assessment Report, A.07-12-009 (Structure Report), p. 10.

[1103] Structure Report, p. 9.

possible issues with PG&E's validation of interval data processing. PG&E is not following industry best practices, creating a lag between data gathering and data validating resulting in increasing manual exception processing.

In D.06-07-027, the Commission noted that the "Joint Parties propose hourly and daily electricity and gas usage data collected via the AMI network should be posted to a data server in an open format immediately following retrieval and any necessary pre-processing."[1104] In the Advanced Metering Investigation decision, the Commission stated that "PG&E should provide free web access to day-after data for individual customers."[1105] PG&E has complied by providing residential customers the ability to access hourly interval data via "My Energy" through PG&E's website.

Now, through GRC funding PG&E is requesting to increase the meter population of customer who need to have exceptions processed manually to all 4.6 million electric customers so that all electric customers with SmartMeters have access to billing quality data. DRA questions the usefulness of providing all customers with billing quality data when customers currently have access to pre-billing quality data. Funding approved in D. 06-07-027 was intended to, and should, enable PG&E to implement a system which would reduce the amount of time for data exception processing (coinciding with Smart Meter deployment) with the capability to provide accurate data to all customers for web presentment and billing purposes.

In D. 07-12-009, the Commission stated:

> Regarding future costs that may be related to the original AMI project or the Upgrade and which are raised in separate proceedings for the purpose of additional rate recovery, they are only speculative at this time. We can only note that, in order to get such additional rate recovery, PG&E has the burden to show that such costs are neither covered by specific costs adopted in either proceeding nor by risk based allowances adopted in either proceeding.[1106]

PG&E has not provided any information to show that the funding it requests in this GRC proceeding is not covered by funding approved in other proceedings.

[1104] D.06-07-027, p. 55; 2006 Cal. PUC LEXIS 274.

[1105] D.06-07-027, p. 66, Conclusion of Law 16.

[1106] D.09-03-026, p. 89; 2009 Cal. PUC LEXIS 136.

PG&E says its planned Interval Data Processing and Exception Management project should be operational in late 2015 that will reduce the need for manual intervention for exception processing.[1107] PG&E has already been allocated funding through the Original AMI and Smart Meter Upgrade decisions to implement the Interval Data Processing and Exception Management project or similar project. Due to delays in implementation, PG&E is now requesting incremental funding for the IT project and ongoing maintenance of manually validating interval customer data through 2017.

DRA accepts the $5.3 million in incremental savings as identified in D.06-07-027[1108] for "exception processing" and "automated interval billing" respectively. DRA recommends no incremental ratepayer funding for 2014 beyond escalation for data processing and billing-related work.[1109]

With regarding to the four business analyst positions to support Billing Operations[1110] for 2014, DRA recommends no incremental funding beyond 2011 recorded levels. These positions are associated with the same or similar interval data processing work for which PG&E has already been authorized funding.[1111]

Smart Meter Opt-Out Program

For 2014, PG&E requests an increase of $0.8 million over 2011 recorded expenses for Billing Operations to respond to Opt-Out requests and process meter-related transactions.[1112] DRA recommends a 2014 expense of $0.2 million for Billing Operations support of the Smart Meter Opt-Out program. In addition, DRA recommends that starting in 2014, all Opt-Out expenses, capital expenditures, and revenues, be booked in a one-way balancing account as explained below.[1113]

In response to a DRA data request about PG&E's Opt Out forecast, PG&E stated:

[1107] Ex. 22 (PG&E-5), p. 4-18, lines 5-10.

[1108] Ex. 22 (PG&E-5), p. 10-7, Table 10-1, lines 7, 15.

[1109] Ex. 81 (DRA-13), p. 54.

[1110] Ex. 22 (PG&E-5), p. 4-18, lines10-11.

[1111] Ex. 81 (DRA-13), p.54.

[1112] Ex. 22 (PG&E-5), p. 4-18, lines 17-22.

[1113] Ex. 81 (DRA-13), p. 54.

> The estimated number of CSRs needed to process the Opt-Out Program work in 2012 through 2014 is based on PG&E's best judgment and experience with the Opt-Out Program since its February 1, 2012 inception. No additional detailed analysis is available to support the staffing levels shown on page WP 4-28.[1114]

PG&E's Opt-Out program started on February 1, 2012,[1115] PG&E states that the 2012 recorded expense of performing such work in 2012 was $1.258 million, or $58,000 above its original 2012 forecast.[1116] However, this was a time when customers were first offered the option to Opt-Out, resulting in higher levels of work than is likely for ongoing maintenance of the program. The total Opt-Out enrollment as of December, 31 2012 was 33,525 customers.[1117] For 2014, PG&E has forecasted 70 additional Opt-Out customers[1118] (for new residential customers), a fraction of the recorded enrollment in 2012.

With the completion of PG&E's Opt-Out Automation Information Technology (IT) Project in December 2012, "information for customers who enroll or un-enroll using PG&E's webpage is automatically uploaded to PG&E's Customer Care and Billing (CC&B) system."[1119] In A.11-03-014, the Smart Meter "Opt-Out" proceeding, PG&E identifies Billing Operations monthly operating expenses forecast of $175,000 in November and $59,536 in December (due to the implementation of the Opt-Out Automation IT Project) and $59,536 monthly for all of 2013,[1120] a reduction of $115,464 per month due to the implementation of the Opt-Out Automation IT Project. This forecast assumes monthly Opt-Out enrollment of 1,796 customers or 2,992 meters in 2013.[1121] PG&E forecasts the number of "Additional Forecast Opt-Out Customers in 2014" of 70 for a total additional number of 139 meters in 2014 less than 5% of PG&E's 2013 forecast.[1122]

[1114] Ex. 81 (DRA-13), p.55 citing PG&E's response to DRA_151-Q05.

[1115] Ex. 81 (DRA-13), p. 55 citing PG&E's response to DRA_151-Q05.

[1116] Ex. 81 (DRA-13), p. 55 citing PG&E's response to DRA_151-Q05.

[1117] Ex. 81 (DRA-13), p. 55 citing PG&E's response to DRA_208-Q11.

[1118] Ex. 81 (DRA-13), p. 55 citing PG&E-5, WP 10-12, line 12.

[1119] Ex. 81 (DRA-13), p. 55 citing PG&E's response to DRA_151-Q05, p. 2.

[1120] Ex. 81 (DRA-13), p. 55 citing A. 11-03-014, WP 2-3, line 2.

[1121] Ex. 81 (DRA-13), p. 55 A. 11-03-014, WP 1-3, line 8.

[1122] Ex. 23 (PG&E-5 workpapers), p. WP 10-12, line 12.

PG&E states in A.11-03-014, "'After IT Project is operational in December 2012, assumes required incremental labor decreases to a team of seven incremental CSRs who will process exception handling for SOP bills and enroll new SOP customers. This assumes an average annual Billing Operations CSR Salary in 2013 dollars of $102,061."[1123]

Although the language PG&E uses in this GRC testimony to describe the activities which will be performed by Billing Operations for Opt-Out option work is slightly different, the work is essentially the same--to respond to Opt-Out requests and process meter-related transactions.[1124] In A.11-03-014, PG&E forecasted 7 CSRs to perform opt-out related work in 2013 (book in a balancing account), while in the 2014 GRC, PG&E is requesting 8 Business Analysts for less than 5% of the "Opt-Out" customer requests of PG&E's 2013 forecast.

Given the drastic reduction in the number of new Opt-Out customers forecast by PG&E for 2014 (reducing the need for processing), and implementation of the Opt-Out Automation, DRA recommends 2 incremental FTEs in 2014 over 2011 staffing levels to process Opt-Out requests and meter-related transactions at a 2014 expense of $198,000.[1125]

DRA recommends the Commission adopt a one-way balancing account for all Opt-Out costs and revenues as the actual costs in 2014 are dependent on the results of A.11-03-014. The Opt-Out proceeding also impacts several other expenses, small capital additions, and revenues. DRA proposes a one-way balancing account due to the overstated and sometimes contradictory forecasts between PG&E's A. 11-03-014 and this GRC proceeding. A one-way balancing account is also warranted given the uncertainty of the outcome of A.11-03-014 and customer's reactions to whatever that decision is, and the uncertainty of the actual costs and revenues which will be incurred and collected by PG&E for activates such as Billing Operations, Meter Reading, Field Collection Activities, Network Monitoring, Meter Installations, Mesh Network Device Installations, and associated revenues. Moreover, adoption of DRA's recommendation in this GRC has the added benefit of giving PG&E an incentive to control expenses and capital expenditures related to the Opt-Out program.[1126]

[1123] Ex. 81 (DRA-13), p. 56, citing A. 11-03-014, WP 2-3, note 2.

[1124] Ex. 81, p. 56.

[1125] Ex. 23 (PG&E-5 workpapers), p. WP 2-26, cost per CSR line 6.

[1126] Ex. 81 (DRA-13), p. 56.

Relocation of Billing Operations Group

For 2014, PG&E requests a $0.8 million dollar increase over 2011 recorded expenses to relocate the Billing Operations group, currently based in Stockton, to a new leased facility. DRA recommends no incremental ratepayer funding for this relocation.[1127]

PG&E says that relocation of the Billing Operations is "…being done in part to accommodate the increased staffing mentioned previously."[1128] PG&E has already moved some employees to a building in the city of Fremont. Thus, it appears that the current offices are sufficient as PG&E has already shifted employees to accommodate increases billings operations from 2011-2012. In any event, DRA does not support the incremental staffing PG&E forecasts as discussed elsewhere in this Brief.

In Rebuttal, PG&E devotes two pages to describing the inadequacies of the Stockton facility including heating and air conditioning problem and limited parking, and alludes to instances of car theft, drug dealing and shots fired in the vicinity.[1129] None of this appeared in the one paragraph PG&E submitted in its direct Customer Care testimony. In fact, the only reason PG&E did give was "to accommodate the increased staffing" it is seeking in the Customer Care organization.

DRA continues to recommend no incremental ratepayer funding for a relocation of the Billing Operations group.

Customer Billing

For 2014, PG&E is requesting an additional $0.3 million over 2011 expenses to address growth in the Net Energy Metering (NEM) population by adding 3 Business Analyst positions within Customer Billing to augment the 12 employees currently performing this work.[1130] DRA recommends no incremental ratepayer funding beyond 2011 recorded expenses for 2014.[1131]

[1127] Ex. 81 (DRA-13), p. 58

[1128] Ex. 22 (PG&E-5), p. 4-18, lines 25-30.

[1129] Ex. 57 (PG&E-20), pp. 4-12 – 4-14.

[1130] Ex. 22 (PG&E-5), p. 4-18 and 4-19, lines 32-34 and 1-3.

[1131] Ex. 81 (DRA-13), p. 59.

PG&E states the NEM population has been increasing at a rate of 20% per year from 2009-2011.[1132] In connection with its Customer Care Technology Projects forecast to be completed in 2013,[1133] PG&E describes the new functionalities of the NEM Billing IT project as:

> Net Energy Metering (NEMs) Billing will mitigate the business continuity risk of overburdening the ABS system, allow for cost savings due to NEMS accounts being worked by CSRs rather than specialized Meter to Cash resources, improve operational efficiencies by reducing the need to provide customers with two billing statements from both ABS and CC&B, provide the capabilities of allowing customers to review consumption, generation and receivable information on a single billing statement instead of performing manual reconciliation across two system generated statements. With the approval of Assembly Bill 920, customers have been given incentives for generation credits, the enrollment rate could increase thereby adding scalability risks to the existing ABS legacy system.[1134]

PG&E has not quantified the operational efficiencies, or included them to offset requested funding increases for 2014. Therefore, DRA recommends no incremental ratepayer funding beyond 2011 recorded in 2014 to support NEMs Billing.[1135]

Bill Printing and Mailing

PG&E's Bill Print and Mail (BPM) operation prints and mails customer bills, credit notices, checks (payroll, accounts payable and customer refunds).[1136] For 2014, PG&E requests two incremental FTEs increases over 2011 funding and one decrease for a total incremental increase over 2011 recorded expenses for 2014 total expenses of $2.2 million.[1137] DRA recommends a $0.8 million increase over 2011 recorded expenses for 2014, an adjustment of $1.4 million to PG&E's forecast, explained below in the sections related to Electronic Bill Presentment, Bill Print Costs, Revenue and Statistics, and Streetlight Inventory Project.

[1132] Ex. 22 (PG&E-5), p. 4-19, lines 3-5.

[1133] Ex. 23 (PG&E-5 workpapers), p. WP 9-102.

[1134] Ex. 23 (PG&E-5 workpapers), p. WP 9-103, see fourth bullet point.

[1135] Ex. 81 (DRA-13), p. 60.

[1136] Ex. 22 (PG&E-5), p. 4-13, lines 8-10.

[1137] Ex. 22 (PG&E-5), p. 4-20.

Electronic Bill Presentment

For 2014, PG&E requests an additional $1.65 million over 2011 expense of $0.7 million[1138] to expand electronic bill (e-Bill) to customers[1139] for a total 2014 Electronic Bill Presentment expense of $2.4 million. DRA recommends $0.3 million in incremental funding for the Test Year for a total 2014 Electronic Bill Presentment expense of $1.0 million.[1140]

PG&E's 2012 recorded data for electronic bill presentment shows that its actual incremental cost from 2011 to 2012 was $85,063[1141] compared with its forecast presented in workpapers of $711,954.[1142] The vendor fees will not increase at the rate forecasted by PG&E due to PG&E's 2012 recorded data being about 12% percent of 2012 forecasted. The Push eBilling, Web eBill Viewing Fees, or Web eBill loading fees, will not increase at rates forecasted by PG&E. DRA recommends a total annual expense of $991,000 an increase of $256,870 above 2011 recorded expenses.[1143]

Bill Print Costs

For 2014, PG&E proposes a $2.2 million decrease from 2011 recorded expenses for paper bill production, as a result of increasing payments by e-Bills.[1144] DRA accepts PG&E's forecasted decrease in paper bill production costs and forecasts, with assumption that the DRA recommended funding level of $991,000 for electronic bill presentment, will provide PG&E with sufficient funding to reach the $2.24 million in savings related to a reduction in mailed bills.

Revenue and Statistics

In 2014, PG&E forecasts increased expense of $0.3 million over 2011 expenses of $2.1 million[1145] within the Revenue and Statistics (R&S) department[1146] for a total 2014 forecasted

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[1138] Ex. 23 (PG&E-5 workpapers), p. WP 4-20, line 6.

[1139] Ex. 22 (PG&E-5), p. 4-19, lines 16-18.

[1140] Ex. 81 (DRA-13), p. 61.

[1141] Ex. 81 (DRA-13), p. 61 citing PG&E's response to DRA_151-Q21 see Atch01, WP 4-21, line 2, third to last column.

[1142] Ex. 23 (PG&E-5 workpapers), p.WP 4-21, line 2, last column.

[1143] Ex. 103 (Ex. DRA-13 workpapers), p. WP 4-3.

[1144] Ex. 22 (PG&E-5), p. 4-19 to 4-20, lines 33-34 and 1-2.

[1145] Ex. 81 (PG&E-13) p. 63 citing PG&E's response to DRA 151-Q28 see Atch01.

[1146] Ex. 22 (PG&E-5), p. 4-20 lines 15-17.

expense of $2.5 million. DRA recommends an increase of $0.1 million beyond 2011 recorded expenses for a total 2014 expense forecast of $2.2 million.[1147]

PG&E's reasons for requesting incremental expenses for 2014 include: (a)the addition of 2 Business Analysts for development and testing of new mass transaction procedures for customer refunds, utility users tax and franchise fee processing; (b) the addition of 1 Business Analyst to support federal 1099 reporting associated with the processing of customer refunds; and (c) moving to Revenue & Statistics the annual contract costs for the Escheat Compliance Fulfillment Services LLC, an outside vendor used by PG&E to identify and contact customers to inform them of monies they may be entitled to.[1148]

PG&E originally forecasted a staffing increase of $260,000 in 2012,[1149] yet recorded 2012 data shows an increase in labor (including taxes and burdens) of $102,000. Therefore, DRA recommends an increase of $102,000 (the actual recorded increase in labor) plus escalation for a total incremental expense of $108,000 for Revenue and Statistics over 2011 expenses for 2014. This equals a total of approximately $2.2 million, which is almost exactly the five year average 2008-2012 recorded expenses for the Revenue and Statistics Department.[1150]

In addition, PG&E included an incremental increase of $0.2 million for "increase of Business Analysts to perform quality assurance, testing, and training development.[1151] PG&E does not explain this increase in its testimony, and it appears these positions come from a workpaper.[1152] In testimony PG&E states "Billing Operations will increase supporting Quality Assurance (QA) positions by four business analyst positions…these positions will provide process evaluation and development, training assessment, and other support activities to Billing Operations."[1153] DRA recommends zero incremental funding for these positions because DRA

[1147] Ex. 103 (DRA-13 workpapers), p. WP 4-5.

[1148] Ex. 22 (PG&E-5), p 4-20, lines 17-28.

[1149] Ex. 23 (PG&E-5 workpapers), p. WP 4-28, line 9.

[1150] Ex. 103 (DRA-13 workpapers), p. WP 4-5.

[1151] Ex. 23 (PG&E-5 workpapers), p. WP 4-28, line 4.

[1152] Ex. 23 (PG&E-5 workpapers), p. WP 4-28, line 2.

[1153] Ex. 22 (PG&E-5), p. 4-18, lines 11-16.

finds no mention in PG&E's testimony of why current staffing levels are inadequate. This results in an adjustment of $.2 million to PG&E's request.[1154]

Street Light Inventory Project

In 2014, PG&E requests an increase in expenses supporting field auditing of streetlights by $374,000[1155] over 2011 expenses of $641,689[1156] a 58% increase above 2011 recorded expenses. DRA recommends no incremental ratepayer funding for 2014 beyond 2011 recorded expenses of $641,689 for the Street Light Inventory Project.

In its Test Year 2011 GRC, PG&E requested incremental funding of $441,000 for Street Light Program Management.[1157]

> This increase will provide for the customer service and support for both customer-owned and PG&E-owned street lights. In 2011, the program will focus on the significant safety, aesthetic, and energy efficiency benefits offered by street lights…[1158]

These specific Street Light Program Management costs are charged to Major Work Category EZ as identified by PG&E in 2009: "the costs of the Program's customer care work and program management activities are charged to MWC EZ."[1159] PG&E's 2014 testimony did not identify any changes to the Street Light Program Management and therefore appears to be booking Street Light Program Management expenses to MWC EZ and the Street Light Inventory Project to Major Work Category IS. It seems PG&E has embedded Street Light Program Management expenses recorded in MWC EZ.

In Rebuttal, PG&E says that it "realigned" costs within MWC IS for the inclusion of the [Street Light Inventory Project] and that "DRA is incorrect that costs for this project are embedded within other MWCs."[1160] This is just one instance of PG&E changing the way it uses Major Work Categories between the last GRC and this one.

[1154] Ex. 81 (DRA-13), p. 64.

[1155] Ex. 22 (PG&E-5), p. 4-20, lines 30-32.

[1156] Ex. 81 (DRA-13), p. 65, citing PG&E's response to DRA_028-Q12.

[1157] Ex. 81 (DRA-13) p. 65 citing A. 09-12-020, Ex. PG&E-4, p. 4-24, lines 4-7.

[1158] Ex. 81 (DRA-13) p. 65 citing A. 09-12-020, Ex. PG&E-4, p. 4-16, Table 4-4, line 5.

[1159] Ex. 81 (DRA-13) p. 65 citing A. 09-12-020, Ex. PG&E-4, p. 4-12, lines 22-23.

[1160] Ex. 57 (PG&E-20), p. 4-24.

The information arrived too late for DRA to verify it. DRA, therefore, continues to recommend no incremental funding for the Street Light Inventory Project in MWC IS for 2014, other than labor and non-labor escalation.

5.4.1.2 MWC IU – Collect Revenue

For Major Work Category IU – Collect Revenue, PG&E requests an incremental increase of $4.5 million over 2011 recorded expenses of $14.9 million, for a total forecasted 2014 expense of $19.4 million.[1161] DRA recommends an incremental increase of $1.6 million over 2011 recorded expenses for a total forecasted 2014 expense of $16.5 million.[1162]

Major Work Category IU includes: (1) payment processing activities related to removing payments from envelopes, capturing payment information, applying payments to individual customer accounts, and completing bank deposits; (2) operation of Neighborhood Payment Centers; (3) researching and responding to customer payment inquiries; (4) revenue control activities related to reconciling payments deposited with amounts credited to customers' accounts; (5) and Revenue Assurance activities.[1163] Of these DRA disagrees with PG&E's forecasts relating to Payment Processing and Revenue Assurance. These are discussed below.

Payment Processing

For 2014, PG&E requests five incremental increases in expenses over 2011 recorded for Payment Processing, for a total increase of approximately $2.2 million. For 2014, DRA recommends incremental funding over 2011 recorded expenses of approximately $1.0 million for increased payment processing activities.

PG&E's forecast includes increases for: (i) $0.5 million to increase electronic payment options for customers; (ii) $1.0 million to support increased pay-by-phone activities; (iii) $0.3 million for staffing increase by three business analysts to support the expansion of electronic payment options for customers; (iv) $0.3 million for marketing to make customers aware of new payment options; (v) $0.1 million for increased maintenance and operation of ten new self-service payment kiosks added in 2011.[1164]

[1161] Ex. 22 (PG&E-5), p. 4-2.

[1162] Ex. 81 (DRA-13), p. 66.

[1163] Ex. 22 (PG&E-5), p. 4-21, lines 11-18.

[1164] Ex. 22 (PG&E-5), p. 2-26 and 2-17, lines 21-33 and 1-6.

DRA accepts PG&E's forecast relating to its payment kiosks, but recommends adjustments to PG&E's other estimates. DRA's recommendations are as follows: (i) $0.4 million for increase in vendor fees for electronic payment processing; (ii) $0.55 million to support increased pay-by-phone activities; (iii) no incremental ratepayer funding for staffing increases to support the expansion of electronic payment options for customers; (iv) zero incremental funding for marketing to make customers aware of new payment options; (v) $0.1 million for increased maintenance and operation of ten new self-service payment kiosks added in 2011.[1165] DRA's adjustments are mostly based on PG&E's lower 2012 recorded expenses that what PG&E forecasted in its application.[1166]

Electronic Payment Options

For 2014, PG&E requests an increase in spending of $0.5 million beyond 2011 recorded expenses of $4.15 million[1167] for a total forecasted 2014 Electronic Payment Options expense of $4.65 million. For 2014, DRA recommends an increase in spending of $0.4 million beyond 2011 recorded expenses of $4.15 for a total forecasted 2014 Electronic Payment Options expense of $4.55 million.[1168]

PG&E's Workpapers PG&E's 2011 recorded costs of $4.155 million for vendor fees for electronic payment processing.[1169] In 2012, PG&E's costs for vendor fees for electronic payment processing were below what PG&E forecasted by $89,000.[1170]

For 2014, PG&E requests an increase in web based payments of approximately 200% of 2012 recorded payments due to the introduction of the one-time payment option.[1171] PG&E states that "… based the forecast of Web based payment volumes as essentially flat for enrolled

[1165] Ex. 111 (DRA-13 workpapers), p. WP 4-3.

[1166] Ex. 81 (DRA-13), p. 68.

[1167] Ex. 23 (PG&E-5 workpapers), p. WP 4-20, line 1.

[1168] Ex. 81 (DRA-13), p. 68.

[1169] Ex. 23 (PG&E-5 workpapers), p. WP 4-20, line 1.

[1170] Ex. 81 (DRA-13), p. 69 citing PG&E's response to DRA_151-Q21, tab WP 4-20, line 1.

[1171] Ex. 23 (PG&E-5 workpapers), p. WP 4-23, see note for lines 16-17.

customers with recurring payments,"[1172] yet PG&E has forecasted an increase in enrollment of almost 1.6 million payments, or 146%, above 2012 payments.

PG&E's contradictory language does not appear to correspond to its forecast and PG&E's 2012 spending is well below what it forecasted in its application. DRA, therefore, recommends an incremental expense of $0.4 million over 2011 expenses for a total 2014 recommendation of $4.55 million.[1173]

Increase in Pay-by-Phone Activities

For 2014, PG&E forecasts an increase in spending of $1.0 million beyond 2011 recorded expenses of $0.2 million for a total forecasted 2014 expense of $1.2 million to support Pay-by-Phone transactions and mobile device payment channels.[1174] DRA recommends an increase of $0.65 million beyond 2011 recorded expenses for a total forecasted 2014 expense of $0.85 million.[1175]

Although PG&E does not directly state so in testimony, it appears that the increases in Pay-by-Phone transactions are for the customers who try to pay through mobile devices, but experience problems. Once this occurs, the customer is transferred to an agent where the customer's payment is made via a phone call, rather than through an electronic transaction. Based on this understanding, DRA used 2012 data to forecast the level of Customer Service Representative (CSR) payments and inquiries for 2014.

Using a formula derived from the number of mobile payments and CSR-assisted payments and inquiries in 2012, DRA calculated a $0.3 million reduction to PG&E's forecast.[1176]

In Rebuttal, PG&E says:

> DRA bases its recommendation on an erroneous assumption that pay-by-phone customer assistance phone costs are inked to mobile payments. The two payment channels are completely different and not linked. The forecasted customer assistance costs are for

[1172] Ex. 23 (PG&E-5 workpapers), p. WP 4-23, see note for lines 16-17.

[1173] Ex. 81 (DRA-13), p. 69.

[1174] Ex. 23 (PG&E-5 workpapers), p. WP 4-22, lines 7-9.

[1175] Ex. 81 (DRA-13), p. 69.

[1176] Ex. 81 (DRA-13), p. 70.

> PG&E's pay-by-phone vendor for customers who have difficulty trying to make a payment in the automated phone system.[1177]

PG&E's Direct testimony provides no explanation at all of how PG&E arrived at its forecast increase for Pay-by-Phone activities. Its workpapers include the only explanation DRA could find in a Note to a Table entitled "Derivation of Electronic Payment Program Costs by Channel. According to that Note: PG&E based the forecast for assisted pay-by-phone volumes on existing call volumes with our current vendor, and some industry and benchmarking studies of the introduction of similar payment services in other markets. Volume increases are based on customer growth and the increased marketing of mobile options to customer"[1178]

Using PG&E's recorded 2011 expenses of $0.2 million; DRA recommends a 2014 expense for mobile transactions of $0.64 million an adjustment of $0.56 million to PG&E's 2014 forecast of $1.2 million.

Staffing Increase to Support Electronic Payment Transactions

In 2014, PG&E requests funding to increase staffing within Payment Processing by three business analysts positions to support the expansion of the electronic payments options for customers at an expense of $0.3 million over 2011 expenses.[1179] DRA recommends no incremental funding increased staffing to support electronic payment transactions in 2014.

PG&E stated in response to a DRA data request:

> The Pay Channels department was established in 2011 to consolidate management of PG&E's electronic billing and payments programs. Prior to 2011, this function was dispersed among multiple organizations within PG&E.
>
> In planning staffing for the new department, it was determined that three additional positions would be required to support management of these programs along with the work required to implement the Electronic Pay Channel Consolidation Project currently underway. The determination of the number of new employees needed was based on PG&E's best judgment and experience with project management and product implementation

[1177] Ex. 57 (PG&E 20), p. 4-15.

[1178] Ex. 23 (PG&E workpapers), p. WP 4-23, Note to Line 36.

[1179] Ex. 22 (PG&E-5), p. 4-26, lines 25-29.

functions. No additional detailed analysis is available to support the staffing levels shown on page WP 4-20.[1180]

Based on PG&E's answer to this DRA data request, and specifically PG&E's statement that "this function was dispersed among multiple organizations within PG&E," PG&E has embedded funding to support the Pay Channels function for 2014.[1181] DRA continues to recommend no incremental funding for 2011 for increases to staffing to support the Payment Processing.

Marketing of New Payment Options

For 2014, PG&E requests incremental spending over 2011 recorded expenses of $0.3 million for a marketing effort to make customers aware of new payment options. DRA recommends zero incremental over 2011 recorded expenses for marketing of new payment options in 2014.

PG&E recorded 190,500 recorded mobile payment transactions in 2011[1182] and increased that number to 579,026 in 2012.[1183] DRA asserts that the mobile payment option is not a new payment option for 2014 and PG&E experienced a more than 300% growth in mobile payments from 2011 to 2012. Other payment options such as home banking and payments through PG&E's website are not new for 2014 either.

In a marketing campaign conducted in 2012 for PG&E's neighbor payment centers (NPC) "the costs for materials, printing, and mailing were paid for entirely by CheckFreePay, PG&E's (NPC) vendor. A follow up mailing to the same customers with similar content is planned for February 2013."[1184] This statement highlights that most if the expenses for the NPC marketing campaign were incurred by PG&E's vendor rather than PG&E. PG&E also identified a another initiative currently in the planning/analyze stage the "Channel of Choice Initiative designed to provide customers with the ability to conduct services with PG&E in the manner that

[1180] Ex. 81 (DRA-13), p. 70, citing PG&E's response to DRA_151-Q. 06, p. 2.

[1181] Ex. 81 (DRA-13), p. 71.

[1182] Ex. 23 (PG&E-5 workpapers), p. WP 4-23, line 12.

[1183] Ex. 81 (DRA-13), p. 72 citing PG&E's response to DRA_151-Q21see Atch01 WP 4-23, line 12.

[1184] Ex. 81 (DRA013), p. 72 citing PG&E's response to DRA_126-Q05.

the customer chooses as best suited for their unique needs."[1185] It appears this marketing campaign will be implemented in 2013.

DRA recommends no incremental ratepayer funding for marketing. If, however, the Commission approves any ratepayer funding for "Marketing for New Payment Options," then DRA recommends that the Commission also establish a mechanism by which it can assess whether PG&E has used ratepayer funds effectively.[1186]

Revenue Assurance

In 2014, PG&E requests an increase of 13 field representatives to perform Revenue Assistance work, at an incremental expense of $1.3 million over 2011 recorded expenses of $3.0 million[1187] for a total 2014 forecast of $4.3 million. DRA recommends no incremental ratepayer funding for 2014, for an adjustment of $1.3 million to PG&E's 2014 forecast.

PG&E forecasts an increase in Revenue Assurance staffing "in response to increased workloads in this area."[1188] In the course of discovery DRA learned that the number of processed meter tampering cases has declined yearly from 2008 to 2012, and that the cost per case has increased 32% from 2008 to 2012 (in base year 2011 dollars, $823 to $1,084).[1189]

In PG&E's test year 2011 GRC, PG&E requested an additional four Revenue Assurance representatives for the essentially the same reasons: more data provided by the system leading to more cases as explained below.

> PG&E's SmartMeter™ Program is scheduled to be deployed system wide by 2012 and the company is expecting the data provided by this system will help us to identify more cases of tampering than had previously been identified by manual meter reading. Each of these additional cases will require resources to allow for investigation and resolution. Labor and non-labor escalation. Based on the above factors, PG&E has determined the need for four additional RA representatives in 2011 to effectively manage this increasing RA workload.[1190]

[1185] Ex. 81 (DRA-13), p. 72 citing PG&E's response to DRA_126-Q08.

[1186] Ex. 81 (DRA-13), p. 72.

[1187] Ex. 81 (DRA 13), p. 73 citing PG&E's response to DRA_151-Q16, see atch01, tab 17d.

[1188] Ex. 22 (PG&E-5), p. 4-27, lines 8-9.

[1189] Ex. 81 (DRA 13), p. 73 citing PG&E's response to DRA_151_Q17 see Supp01, tab 17a, b, c.

[1190] Ex. 81 (DRA 13), p. 75 citing A.09-12-020, Ex. PG&E-4, p. 8-24, lines 12-22.

Recorded data shows the number of cases has actually declined since the implementation of Smart Meters, yet PG&E uses the same argument for 2014. DRA accepted PG&E's forecast in A. 09-12-020.[1191] In this GRC, DRA opposes PG&E's request for an increase for Revenue Assurance positions.

With the number of meter tampering cases declining historically and PG&E's unsubstantiated claim of increasing costs DRA recommends no incremental ratepayer funding for 2014 over 2011 recorded expenses of $3.0 million. DRA recognizes that meter tampering can be a safety issue and encourages PG&E's efforts to address it.

But meter tampering has always been a safety issue, and PG&E should have been addressing it all along. In fact, given PG&E's statement in its Customer Care testimony in the last GRC that it was "focused on providing safe and reliable electric and gas service,"[1192] PG&E should have embedded costs already to deal with meter tampering in this GRC period. PG&E's request for more ratepayer money without some showing that PG&E will use it effectively should be denied.

5.4.1.3 MWC IT – Manage Credit

For 2014, PG&E forecasts a decrease of $2.0 million to 2011 recorded expenses of $24.6 million in Major Work Category IT – Manage Credit. PG&E's total expense forecast is thus $2.6 million.[1193] For 2014, DRA forecasts a decrease of $5.1 million to 2011 recorded expenses of $24.6 million for total expense forecast of $19.4 million.

Activities under Major Work Category IT include: (1) management of credit related transactions conducted by the Credit Operations Center; (2) the production of mailing of credit related notices in the Bill Print Mail center; and (3) field collection activities conducted by Customer Field Service on behalf of Credit Operations.[1194] For the above activities PG&E forecasts an overall reduction in 2014 expenses below 2011 recorded expenses of $2.2 million due mostly to Smart Meter benefits and the inclusion of 15-day credit notices on the subsequent

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[1191] Ex. 81 (DRA-13), p. 65 citing A.09-12-020, Ex. DRA-10, p. 29, lines 7-12.

[1192] Ex. 21 (PG&E-5), p. 1-1.

[1193] Ex. 22 (PG&E-5), p. 4-2, Table 4-1, line 4.

[1194] Ex. 22 (PG&E-5), p. 4-28, lines 27-31.

bill[1195] (pursuant to the CPUC final decision on Phase 2 of the Disconnect OIR),[1196] decreases are offset by various staffing increases, relocation of the Meter To Cash Billing and Credit Operations, and labor escalation.

For 2014, PG&E requests an increase in expenses for credit operations for staffing of 10 positions for $1.0 million and new software in the amount of $0.3 million for a total incremental expense for 2014 of $1.3 million. DRA accepts PG&E's incremental increase of $1.3 million as will support revenue collection activities to drive a reduction in uncollectibles.

DRA recommends three adjustments to PG&E's 2014 forecast for MWC IT. They are as follows: (1) an adjustment of $667,000 consistent with DRA's opposition to PG&E's proposal to move the Credit and Billing Operations facility, discussed above (2) the removal of Smart Meter Opt-Out funding for Field Collection of $2.1 million[1197] to a one-way Smart Meter Opt-Out balancing account, also discussed above, and (3) a total 15-day credit notice savings of $1.9 million, an incremental decrease of $0.1 million from PG&E's forecast.

PG&E's 15-day credit notice forecast uses a forecasted quantity of 15 day notices of 3.6 million,[1198] while in response to DRA discovery PG&E recorded 4.4 million in 2011 and 4.5 million in 2012.[1199] DRA averaged 2011 and 2012 and applied PG&E's forecasted cost per notice savings to forecast a recommended $1.9 million in savings.

DRA continues to recommends a total of approximately $2.9 million[1200] in adjustments for a total expense forecast for Major Work Category IT of $19.4 million.

5.4.2 Capital Expenditures

In 2014, PG&E plans to relocate two departments, Billing Operations and Credit Operations, to a new leased facility in 2014. The departments will relocate to a larger upgraded facility to accommodate staffing growth for a forecasted capital expenditure of $9.0 million in

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[1195] Ex. 22 (PG&E-5), p. 4-33, lines 28-29.

[1196] Ex. 23 (PG&E-5 workpapers), p. WP 4-46, line 16.

[1197] Ex. 22 (PG&E-5), p. 4-34, lines 2-3.

[1198] See Ex. 23 (PG&E-5 workpapers), p. WP 4-36, line 11.

[1199] Ex. 81 (DRA 13), p. 77, citing PG&E's response to DRA_151-Q27 see atch01.

[1200] Ex. 103 (DRA-13 workpapers), p. WP 4-1.

2014.[1201] DRA does not support the staffing increases forecasted by PG&E and therefore recommends no ratepayer funding for the relocation of the Billing and Credit Operations.

5.4.3 Mechanism Regarding the Service Disconnection Memorandum Account

DRA has no comment on this issue at this time.

5.4.4 Non-Sufficient Funds Fees and Reconnection Fees

DRA does not oppose PG&E's proposals in these areas.

5.4.5 Uncollectibles Mechanism

In previous GRC proceedings, PG&E, like other California Investor-Owned Utilities (IOUs), has been allowed recovery for bad debt write-off by way of a CPUC-adopted uncollectibles factor.[1202] The uncollectibles factor has historically been adopted for the given GRC cycle, generally based on historical and economic factors.

PG&E proposes several changes to the process by which it will be compensated for uncollectibles from 2011 forward. PG&E claims that, "[g]iven the current economic volatility, on a going-forward basis the current uncollectibles factor-based mechanism, in spite of its prior acceptance, will expose customers and the utility to excessively large risks between rate cases and significant future adjustments."[1203]

PG&E requests an uncollectibles factor based on a 5-year rolling average that adjusts annually with a one year lag from the current year. PG&E says that, "… as an example, the average uncollectibles for the period of 2007-2011 would be the average used and applied to 2013 performance and rates. In addition, changes in the base factor (up or down) would be built into rates via an annual advice letter filing."[1204] PG&E's proposed uncollectibles mechanism results in a 2014 factor of 0.00376, 21% above its current authorized factor of 0.003105.

DRA recommends an average of years 2003-2012 recorded uncollectibles factor removing the lowest and highest recorded years to account for the abnormally high and low years of 2009 and 2006 respectively. This leads to a 2014 uncollectible factor of 0.003199.

[1201] Ex. 22 (PG&E-5), p. 4-37, lines 12-17.

[1202] Ex. 22 (PG&E-5), p. 4-37, lines 20-22.

[1203] Ex. 22 (PG&E-5), p. 4-39, lines 11-15.

[1204] Ex. 22 (PG&E-5), p. 4-41, lines 1-14.

DRA's forecast is a slight increase above PG&E's authorized 2011 write-off of factor of 0.003105. DRA also recommends that the Commission continue to address uncollectibles through the GRC, rather than allowing PG&E to change its base factor via an annual advice letter filing. DRA's forecast uses more historical data to smooth the variable of economic conditions, while PG&E's proposal places greater weight on the economic downturn experienced by California from 2008-2011.[1205]

PG&E's current uncollectibles factor is substantially higher than SCE's current authorized write-off factor of 0.00205.[1206] DRA has accepted PG&E's request for new software and an incremental 10 positions for Credit Operations, an apparent problem area for PG&E as highlighted by its historical uncollectibles rate. DRA's proposal is supported by historical experience and will give PG&E an incentive to implement new strategies and policies to reduce under-collection.

5.5 Metering

In 2014, PG&E requests $74.7 million for Metering Programs, a 231% increase above the 2011 recorded expense of $32.3 million.[1207] DRA recommends $24.1 million, a decrease of $8.3 million below 2011 recorded expenses of $32.3 million, an adjustment of $50.6 million to PG&E's request.[1208]

5.5.1 Expense

PG&E presents its 2014 request for Metering Programs for activities within the Field Meter Operation and Meter Asset Management organizations. Expenses for these activities are recorded in Major Work Categories: AR Read Investigate Meters, DC Dispatch Customer Service, DD Provide Field Service, EY Change/Maintain Used Electric Meters, and HY Change/Maintain Used Gas Meters.[1209] PG&E forecasts total 2014 expenses of $74.6 million,

[1205] Ex. 81 (DRA-13), p. 80.

[1206] D.12-11-051, p. 337.

[1207] Ex. 22 (PG&E-5), p. 5-2, lines 8-11.

[1208] Ex. 81 (DRA-13), p. 82.

[1209] Ex. 22 (PG&E-5), p. 5-2 to 5-3.

which is an increase of $42.3 million beyond 2011 recorded expenses of $32.3 million, or a 231% increase.[1210]

5.5.1.1 MWC AR – Read and Investigate Meters

For 2014, PG&E forecasts $32.0 million in meter reading expenses, comprising $27.9 million due to residential Smart Meter Opt-Out (SMO) customers[1211] and $4.7 million due to non-communicating devices needing to be manually read.[1212] For 2014, DRA forecasts SmartMeter Opt-Out expenses of $7.5 million,[1213] an adjustment of $20.4 million to PG&E's forecast of $27.9 million, which DRA recommends be recorded in a one-way balancing account, as discussed above. For the remaining meter reading expenses for non-communicating SmartMeters and locations which require manual reads, DRA forecasts $1.6 million, an adjustment of $3.1 million to PG&E's forecast of $4.6 million.[1214] DRA subtracts from its $1.6 forecast PG&E's forecasted revenues from Customer Access Charges of $0.6[1215] million for a total recommendation of $1.0 million.[1216]

The field meter reading expenses for the Read and Investigate Meters Program are charged to MWC AR – Read and Investigate Meters, which includes senior meter readers, clerical support and management team who work to manually read meters each month.[1217] Pursuant to D.11-05-018, meter costs are being recorded in a balancing account throughout the 2011 GRC cycle (2011-2013). PG&E's meter reading balancing account (MWC IG) recorded amount was $73 million in 2011.[1218]

To forecast 2014 meter reading expenses, DRA used PG&E's cost per meter read forecast of $11.60 and forecasted Opt-Out population at the end of 2013 from the PG&E Smart

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[1210] Ex. 22 (PG&E-5), p. 5-3.

[1211] Ex. 81 (DRA 13), p. 84 citing PG&E's response to DRA_167-Q01.

[1212] Ex. 23 (PG&E-5 workpapers), p. WP 5-2.

[1213] Ex. 23 (PG&E-5 workpapers), p WP 5-2.

[1214] Ex. 23 (PG&E workpapers), p. WP 5-2.

[1215] Ex. 23 (PG&E-5 workpapers), p. WP 5-50, line 2.

[1216] Ex. 81 (DRA-13), p. 84.

[1217] Ex. 22 (PG&E-5,) p. 5-12, lines 5-10.

[1218] Ex. 22 (PG&E-5), p. 5-14.

Meter Opt-Out program proceeding,[1219] plus the 70 incremental Opt-Out premises forecasted by PG&E[1220] in 2014 to reach DRA's recommended expense of $1.6 million.[1221]

PG&E's 2014 request for non-Opt-Out meters requiring manual reads identifies two causes for manual reads: (1) Locations Where Conditions Require Manual Reads, and (2) Smart Meter Maintenance.[1222]

DRA recommends the Commission reject PG&E's assumption that SmartMeter maintenance meters will need to be read manually for three months. DRA recommends using one month per meter, as one month should be sufficient time for PG&E to remediate communication errors. In addition, DRA uses PG&E's 2012 "recorded Electric meters and Gas modules replaced" due to corrective maintenance number of 64,565[1223] with an adder of 500 meters (to account for increased number of installed meters and new residential customers) for a total of 65,065 reads per year due to non-communicating devices. DRA's forecast of 65,065 is a reduction of 148,475 to PG&E's 2014 forecast of 213,540 reads which PG&E says "is for a small number of Smart Meters/modules that are expected to fail for various reasons that will need to be replaced or repaired."[1224]

For Locations Where Conditions Require Manual Reads, DRA accepts PG&E's assertion that these meters will required manual reading each month, but questions PG&E's forecasted meters of 15,600.[1225] In a data request response PG&E said the current number of "technically challenged meter premises is at least 5,978."[1226] DRA uses this number for forecasting "Locations Where Conditions Require Manual Reads" as it is the only data PG&E provided other than its forecast PG&E says that its estimate of approximately 16,000 premises is the best estimate today by the end of deployment.[1227]

[1219] Ex. 81 (DRA 13), p. 85, citing A.11-03-014, workpapers, p. WP 1-3, line 7.

[1220] Ex. 23 (PG&E-5 workpapers), p. WP 10-12.

[1221] Ex. 103 (DRA-13 workpapers), p. 5-2.

[1222] Ex. 23 (PG&E-5 workpapers), p. WP 5-34, lines 6, 7.

[1223] Ex. 81 (DRA 13), p. 85 citing PG&E's response to DRA_208_Q15, p. 2.

[1224] Ex. 23 (PG&E-5 workpapers), WP 5-34, footnote 3.

[1225] Ex. 23 (PG&E-5 workpapers), WP 5-34, line 6.

[1226] See Ex. 81 (DRA 13), p. 86 citing PG&E's response to DRA_208-Q14, p. 2.

[1227] Ex. 81 (DRA-13), p. 86 citing PG&E's response to DRA_208-Q14, p. 2.

DRA expects that PG&E's current "technically challenged meter premises" will decrease as PG&E reaches full deployment and remediates communication issues due to SmartMeter Opt-Out customers. "Customers' opt-out or delay in accepting an electronic SmartMeter has, in some cases, reduced connectivity (i.e., degraded the RF-network) requiring network compensation."[1228] PG&E has requested $10.35 million for IT expenses in the SmartMeter Opt-Out proceeding which, in part, is for remediating Smart Meter network communication issues.[1229] DRA forecasts a total non-Opt-Out meter reading expense for 2014 of $1.6 million, an adjustment of $3.1 million to PG&E's forecast.[1230]

5.5.1.2 MWD DD – Provide Field Service

For 2014, PG&E forecasts expenses in Major Work Category DD – Provide Field Service of $4.96 million. This is a reduction of $4.85 million to 2011 recorded expenses of $9.81 million. DRA accepts PG&E's forecast of million for electric turn-ons and shut-offs under MWC DD for 2014, but due to its allocation of escalation DRA recommends $4.7 million an adjustment of $0.15 million to PG&E's request.[1231]

Since the last GRC, PG&E has reorganized and relocated the gas service personnel to Gas Operations.[1232] Due to the reorganization, Major Work Category DD will be split into three separate organizations: Electric Operations, Gas Operations and Customer Care. The Customer Care Portion of Field Meter Operations under Major Work Category DD includes electric turn-ons and shut-offs and will be completed by electric meter technicians and meter maintenance personnel. Field Meter Operations employees are not responsible for gas turn-ons and shut-offs.[1233]

5.5.1.3 MWD EY – Change/ Maintain Used Electric Meters

PG&E requests a 2014 expense of $26.0 million for Change/Maintain Used Electric meters, which PG&E reduced to $25.7 million, or a $14.2 million increase over 2011 recorded

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[1228] Ex. 22 (PG&E-5), p. 10-3, see footnote 3.

[1229] Ex. 81 (DRA-13) p. 85 citing A. 11-03-014, workpapers, p. WP 4-1.

[1230] Ex. 81 (DRA-13), p. 86.

[1231] Ex. 103 (DRA-13 workpapers), p. WP 4-1.

[1232] Ex. 22 (PG&E-5), p. 5-14, lines 21-23.

[1233] Ex. 22 (PG&E-5), p 5-14 and 5-15, lines 26-30 and 1-3.

expenses of $11.5 million. DRA recommends a 2014 expense of $7.8 million, a reduction of $3.7 million to 2011 recorded expenses and a total adjustment of $18.2 million to PG&E's request.

Starting in 2011 the management of the MWC EY budget includes the incremental cost of operating and maintaining Smart Meter devices. The four activities covered in MWC EY are: (1) installation of electric meters returned through the warranty process; (2) electric meter preventative maintenance; (3) electric meter corrective maintenance; and (4) staff support for electric metering work and activates.[1234]

Routine- Testing Meters

For 2014, PG&E requests incremental expenses of $4.9 million over 2011 recorded expense of $0.3 million for a total 2014 Routine Test (R-Test) program expense of $5.2 million.[1235] In Errata, PG&E decreased its forecast by $0.3 million which was PG&E's 2011 recorded expense level.[1236] For 2014, DRA recommends $0.3 million in expenses for R-Testing plus escalation.[1237]

In 2014, PG&E plans to test 15,000 meters at a forecasted expense of $5.2 million. DRA recommends zero incremental funding beyond 2011 recorded expenses for R-Testing for a number of reasons. First, there is no customer benefit to test meters when more than 99% are testing accurately. Second, customers have the option pursuant to Public Utilities Code Section 394.4(f) to have their meters tested if they believe the meters are inaccurate. Third, increased information transmitted by Smart Meters gives PG&E greater ability to identify and remediate inaccurate meters.

The recorded data of PG&E's R-Tests from 2007 – 2012 shows that Smart Meters are passing at a rate of at least 99% from 2007-2012, which is a much higher pass rate than the 2003-2006 data where 6.4% of meters were removed.[1238]

[1234] Ex. 22 (PG&E-5), p. 5-15, lines 13-20.

[1235] Ex. 22 (PG&E-5), p. WP 5-37.

[1236] Ex. 374 (PG&E-31), p. 2-183.

[1237] Ex. 81 (DRA-13), p. 89.

[1238] Ex. 22 (PG&E-5), p. 5-16, footnote 10.

For all these reasons, DRA recommends funding of $0.3 million in 2014 for R-Testing of a similar number of meters as tested in 2011.

Electric and Gas SmartMeterMeter Maintenance

For 2014, PG&E forecasts for a total 2014 expense for Electric and Gas SmartMeter Maintenance of $15.4 million.[1239] This is an increase in expenses of $6.4 million for electronic meter maintenance over 2011 recorded expenses of $9.0 million. DRA recommends $9.0 million in ratepayer funding for 2014, equal to PG&E's 2011 recorded expenses for these activities, plus escalation.[1240]

PG&E forecasts that electric SmartMeter maintenance work will increase by 25,000 units and gas SmartMeter maintenance by 6,000 units in 2014 over 2011. PG&E forecasts this increase due to several factors: an increased number of deployed Smart Meter devices, an increase in the amount of meters that can be remediated in lieu of replacement when error codes are signaled, and management of additional non-critical error codes beyond those which are currently addressed. PG&E has also included in its 2014 forecast an increase of 5 minutes per job for answering customer questions as a result of engaging in additional customer outreach.[1241]

PG&E states that the "SmartMeter maintenance work is necessary to resolve communication/network issues, flags and alerts being generated from installed SmartMeters that have transitioned to billing utilizing remotely read data. Resolving communication issues that affect billing (delayed/estimated) will not only result in improved billing accuracy and timeliness, but also allow customers to take advantage of the full array of benefits offered with the technology."[1242]

As of January 2013, PG&E has deployed 94.1% of the SmartMeters,[1243] making the increased number of deployed SmartMeter devices incremental to the end of 2014 about 500,000. DRA expects that the relatively small increase in SmartMeter population will be offset by PG&E employees becoming more familiar with this new type of work, thereby increasing

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[1239] Ex. 23 (PG&E-5 workpapers), WP 5-31.

[1240] Ex. 81 (DRA-13), p. 91.

[1241] Ex. 22 (PG&E-5), p. 5-17, lines 1-15.

[1242] Ex. 23 (PG&E-5 workpapers), p. WP 5-31.

[1243] Ex. 81 (DRA-13), p. 93, citing PG&E's response to DRA_103-Q01.

efficiency. DRA's forecast assumes that the network is fully implemented overall, thereby increasing reliability. DRA, therefore, forecasts that SmartMeter Maintenance expenses in 2014 will remain consistent with 2011 levels.[1244]

Field Metering Operations Additional Management

For 2014, PG&E forecasts an additional 8 management personnel between 2011 and 2014 at an expense of $1.5 million in Major Work Category EY. DRA recommends no incremental ratepayer funding beyond escalation for 2014.[1245]

PG&E says its request for 8 new management personnel is due to the organizational split between Gas and Electric Operations, and the fact that additional work has been assigned to Field Metering that included gas module changes and maintenance.[1246] Although these expenses may be new to the Customer Care Organization, PG&E has embedded funding for providing oversight to employees performing gas module changes and maintenance. PG&E's numerous re-organizations appear to be increase the costs of supervision and management, as shown in response to DRA discovery where the supervision and management portion of the Gas Service Representatives (GSRs) went from $6.2 million in 2011 to $24 million in 2012.[1247]

Meter Asset Management and Engineering

For 2014, PG&E is forecasting an additional 18 management personnel between 2011 and 2014 at an expense of $2.1 million, which will be distributed between Major Work Categories EY ($1.4 million) and ($0.7 million).[1248] For 2014, DRA forecasts no incremental funding for either Major Work Category.

PG&E states "[t]he improved efficiencies and streamlined metering asset operations will result in cost avoidances in the following areas…"[1249] and lists five areas. DRA asked PG&E to quantify the "cost avoidances" and in response PG&E stated: "Due to the limited information

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[1244] Ex. 81 (DRA-13), p. 92.

[1245] Ex. 81 (DRA-13), p. 93.

[1246] Ex. 22 (PG&E-5), p. 5-17, lines 16-21.

[1247] Ex. 81 (DRA-13), p. 93 citing PG&E's response to DRA_208-Q04, see Atch01, line 7.

[1248] Ex. 22 (PG&E-5), p. 5-18, lines 17-20.

[1249] Ex. 22 (PG&E-5), p. 5-19, lines 16-17.

currently available, PG&E is unable to quantify cost avoidances at this time."[1250] PG&E has identified no new regulations that are driving PG&E's request for increased ratepayer funding. PG&E has, historically, been assuring meter safety, accuracy, and reliability. The work described in PG&E's Direct testimony[1251] is not new work, and PG&E has embedded funding to cover the expenses for providing the same or similar oversight.

Therefore, DRA forecasts no incremental ratepayer funding beyond escalation for incremental management personnel in Major Work Categories EY in 2014 beyond recorded expenses of $11.5 million and HY recorded expenses of $9.9 million.[1252]

Gas and Electric Meter Services Improvements (GEMS)

For 2014, PG&E requests total 2014 forecast of $4.6 million distributed between Major Work Categories EY.[1253] This is an incremental increase of $3.7 million above 2011 recorded expenses of $0.9 million. DRA recommends an incremental increase of $1.0 million distributed between Major Work Categories EY ($0.8 million) and HY ($0.2 million)[1254] over 2011 recorded expenses, for a total 2014 recommendation of $1.9 million for GEMS.[1255]

To forecast 2014 expenses DRA used PG&E's model which used 2012 funding (a forecast) and then escalated labor expenses by 2.75%. DRA used recorded 2012 labor expenses and escalated to 2014 adding 2.75% for 2013 and 2014 to account for escalation, and averaged operations expenses from 2007-2011 for an operations expense of $0.2 million ($150,000 above PG&E's operations forecast). DRA's forecast of $1.9 million is comparable to the five-year average (2007-2011) and $0.7 million above a three-year average (2009-2011) for work performed by GEMS.[1256]

[1250] Ex. 81 (DRA-13), p. 94 citing PG&E's response to DRA_167-Q26.

[1251] Ex. 22 (PG&E-5), p. 5-18 – 5-19.

[1252] Ex. 81 (DRA-13), p. 94.

[1253] Ex. 22 (PG&E-5), p. 5-20, lines 19-20.

[1254] Ex. 103 (DRA-13 workpapers), p. WP 5-4.

[1255] Ex. 81 (DRA-13), p. 95.

[1256] Ex. 81 (DRA 13), p. 95, citing PG&E's response to DRA_167-Q09 see Atch01.

5.5.1.4 MWC HY – Change/ Maintain Used Gas Meters

For 2014, PG&E requests incremental expenses for Major Work Category HY—Change/ Maintain Used Gas Meters, of $12.0 million. This is an increase of $2.1 million beyond 2011 recorded expenses of $9.9 million.[1257] For 2014, DRA recommends $10.6 million.[1258]

Activities charged to MWC HY are: (1) installation of gas meters or gas modules returned though the warranty process; (2) gas meter preventative maintenance; (3) gas meter corrective maintenance; and (4) staff support for gas metering work and activities.[1259]

Gas SmartMeter Maintenance

PG&E requests incremental funding of $1.2 million for Gas Smart Meter Maintenance over the 2011 recorded expense of $4.1 million dollars, for a total 2014 expense of $5.4 million.[1260] For 2014, DRA recommends 2011 recorded expenses of $4.1 million plus escalation, an adjustment of $1.2 million to PG&E's 2014 forecast.[1261]

Meter Asset Management and Engineering

For 2014, PG&E forecasts incremental funding of $0.7 million above 2011 recorded expense for additional management personnel.[1262] DRA recommends no incremental ratepayer funding for Meter Asset Management and Engineering activities.[1263]

Gas and Electric Meter Services Improvements (GEMS)

For 2014, PG&E requests incremental expenses of $0.7 million above 2011 recorded expenses $0.7 million for a total 2014 expense of $1.4 million.[1264] DRA recommends an incremental increase of $0.2 million for a total 2014 recommendation of $0.9 million, resulting in an adjustment of $0.5 million to PG&E's 2014 request.[1265]

[1257] Ex. 23 (PG&E-5 workpapers), p. WP 5-1, line 5.

[1258] Ex. 81 (DRA-13), p. 96.

[1259] Ex. 22 (PG&E-5), p. 5-20, lines 25-32.

[1260] Ex. 23 (PG&E-5 workpapers), p. WP 5-31.

[1261] *See* Section 5.5.1.3, above.

[1262] Ex. 23 (PG&E-5 workpapers), p. WP 5-30.

[1263] *See* Section 5.5.1.3, above.

[1264] Ex. 23 (PG&E-5 workpapers), p. WP 5-42.

[1265] *See* Section 5.5.1.3, and Ex. 103 (DRA-13, workpapers), p. WP 5-4.

5.5.2 Capital Expenditures

PG&E forecasts total 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.[1266]

PG&E's Metering Capital expenditures include Major Work Categories 01 – IT – Desktop Computers, 05 – Tools and Equipment, 25 – Install New Electric Meters, and 74 – Install New Gas Meters. PG&E says it estimate the capital expenditures for its Metering Programs by (1) deriving unit costs by dividing 2011 recorded capital expenditures by 2011 recorded units; and (2) multiplying the forecast of units by the unit cost and adding escalation (both labor and non-labor) for each forecasted year through 2016.[1267]

DRA forecasts capital expenditures for PG&E's Metering Programs for Major Work Categories 25 and 74 by: (1) using PG&E's 2011 unit cost forecast and escalating using PG&E's escalation factors to derive 2013 and 2014 unit costs to estimate each unit cost; (2) multiplying derived yearly unit 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 includes special projects for regulator replacements and rotary meter replacements in Major Work Category 25, in years 2012-2014.[1268] Although PG&E did not commence this work in 2012, DRA accepts these forecasts for 2013 and 2014, and expects that the work will commence in 2013.[1269]

PG&E includes capital expenditures for Metering in MWC 01 – IT Desktop Computers, for $1.1 million in 2012 which DRA has reduced to the actual recorded expenditure of $.5 million in 2012 and $1.0 million in 2013.

[1266] Ex. 81 (DRA-13), p. 98.

[1267] Ex. 22 (PG&E-5), p. 5-26.

[1268] Ex. 23 (PG&E-5 workpapers), p. WP 5-48 and 5-48A, lines 24-25.

[1269] Ex. 81 (DRA-13), p. 99.

Finally, PG&E forecasts Metering capital expenditures in MWC 05 – Tools for $1.2 million yearly 2012-2014, which DRA accepts as PG&E spent $1.25 million in 2012.[1270]

5.6 Quality Assurance Program/Safety Net Program

DRA has no comments on this area at this time.

5.6.1 Expense

5.6.2 Capital Expenditures

5.7 Customer Energy Solutions

PG&E says its Customer Energy Solutions organization develops, plans and delivers customer products (rate options, energy tools, and customer resources) to industrial and agriculture (LCI & Ag), small and medium business (SMB) and residential customers. PG&E says that Customer Energy Solutions (CES) provides support for community services and economic development within local communities.[1271]

5.7.1 MWC IV – Provide Account Services

For 2014, PG&E requests a total Customer Energy Solutions expense of $80.4 million. This is an increase of $47.7 million, or 146%, over 2011 recorded expenses. For 2014, DRA recommends an expense of $35.6 million, an increase of $2.9 million over 2011 recorded adjusted expenses, equal to a 9% increase.

The areas in dispute are discussed below.

5.7.1.1 MWC IV – Provide Account Services

PG&E requests a 2014 expense of $34.6 million for MWC IV equal to a $24.1 million increase over 2011 recorded expenses of $10.5 million, or a 230% increase. DRA recommends $150,000 incremental funding beyond 2011 recorded expense for a total 2014 forecast of $12.0 million an adjustment of $22.56 million to PG&E's 2014 forecast.

Major Work Category IV was a new Major Work Category developed for the 2011-2013 General Rate Case period, to distinguish Customer Account Services from the more general Major Work Category EZ – Manage Various Customer Care Processes. According to PG&E,

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[1270] Ex. 81 (DRA-13), p. 99.

[1271] Ex. 22 (PG&E-5), p. 7-1.

"MWC IV covers the cost of labor, materials and other expenses incurred in responding to customer inquiries, primarily of non-residential customers, regarding contracts, credit, billing and accounting, collections and complaints."[1272] Employees who charge their time to MWC IV are within the Energy Solutions and Services (ES&S) Department, which is primarily responsible for meeting the needs of PG&E's Large Commercial and Industrial (LCI), Agricultural (Ag), and Small and Medium Business (SMB) customers as well as local communities served by PG&E.[1273]

The ES&S Customer Account Managers generally provide business customers with the following types of service: advise customers on rates, rules and contracts; provide and interpret tariff information; resolve billing, credit and collection issues; facilitate distribution service needs; provide reliability and outage information; coordinate planned outages; provide retail interconnection information; promote EE, DR, and reliability programs; and provide information to customers on conservation and various utility industry issues.[1274]

PG&E says that Customer Account Managers now have iPads. PG&E states "Updating checklist audit product for use on iPad so field representatives can conduct a quick energy survey for our SMB customers and send the customer a report – all from the iPad. Pilot is going well with users reporting decreased time to complete an audit; usage reporting available in 2013 (Launched Pilot 9/30/12; full launch 12/1/12)."[1275] PG&E purchased iPads through funding approved through the Energy Efficiency proceeding (D.09-09-047).[1276]

PG&E says that LCI, Ag and SMB customers now have access to new tools online. "Customer-facing online self-assessment tool on pge.com provides customized energy-saving recommendations that can lower operating costs, and programs that offer financial incentives to implement them."[1277]

[1272] Ex. 81 (DRA 13), p. 76 citing PG&E's response to DRA_082-Q02.

[1273] Ex. 22 (PG&E-5), p. 7-12.

[1274] Ex. 22 (PG&E-5), p. 7-12, lines 16-24.

[1275] Ex. 81 (DRA 13), p. 102 citing PG&E's response to DRA_183-Q13 see Atch08 (TVP Quarterly Report – Dec. 17, 2012, p.35).

[1276] Ex. 81 (DRA 13), p. 102 referencing DRA meeting with PG&E March 13, 2013.

[1277] Ex. 81 (DRA 13), p. 102 citing PG&E's response to DRA_183-Q13 see Atch08 (TVP Quarterly Report – Dec. 17, 2012, p.35).

Customer Account Managers work activities are charged to GRC and Non-GRC sources.[1278]

For 2014, PG&E is requesting an increase of approximately of 146 equivalent full-time employees.[1279] DRA recommends the Commission approve no incremental ratepayer funding for Provide Account Services in this GRC. PG&E has embedded funding from D.11-05-018 (2011GRC), approved funding from D.12-04-045 (EE), D.12-11-015 (DR), and has requested funding through A.10-02-028 (2010 RDW) for 2014.[1280]

Since 2007, ES&S hours recorded to GRC accounts have decreased. On the other hand, non-GRC hours in ES&S have almost tripled in five years, as PG&E has increasingly chosen to charge time spent with LC&I, Ag and SMB customers to non-GRC accounts. DRA is not convinced that PG&E requires an increase in the number of Customer Account Representatives funded through the GRC.[1281]

In PG&E's 2011 GRC, it requested incremental funding beyond 2008 recorded expense for Account Services.[1282] In that GRC, PG&E submitted testimony saying that, "for service improvements within the account services function, PG&E forecasts an increase of $3.30 million over 2008 recorded adjusted expenses. This increase will support the development of: (1) regional energy strategies; (2) innovative customer portfolio offerings; and (3) broader response to service issues of business customers."[1283] It appears from the recorded hours spent by ES&S that the level of service forecasted by PG&E for 2011 was not attained.

PG&E has made numerous organizational changes and department name changes within the Customer Energy Solutions department (including a change of the department name formally Customer Engagement), which makes it difficult to track PG&E's actual spending.[1284] PG&E

[1278] See Ex. 239. See also, Ex. 81 (DRA-13), p. 103-104 for a list of the Approved Sources of Funding for Marketing Education and Outreach 2006-2014 (Table 13-65), and Requested Solurces of Funding for Marketing Education and Outreach 2012-2017 (Table 13-66).

[1279] Ex. 22 (PG&E-5), p. 7-15, lines 1-2.

[1280] Ex. 81 (DRA-13), p. 107.

[1281] Ex. 81 (DRA-13), p. 106.

[1282] PG&E now records expenses for Account Services in MWC IV, rather than MWC EZ.

[1283] Ex. 81 (DRA-13), p. 106, citing A. 09-12-020, Ex. PG&E-4, p. 4-22, lines 6-11.

[1284] Ex. 81 (DRA-13), p. 106 citing PG&E's response to DRA_082-Q3.

forecasted spending $32.2 million[1285] in 2011 for Account Services, but actually only spent about one-third of that amount[1286] for what PG&E now calls Provide Account Services.

PG&E continues to request, and has been approved,[1287] funding for Customer Account Managers through the Demand Response, Energy Efficiency, and Rate Design Window (RDW) proceedings. In this GRC, PG&E seeks even more incremental funding in the amount of $24.1 million dollars.

In Rebuttal, PG&E says that:

> [a]lthough customer account managers have also been funded through non-GRC funding sources such as Energy Efficiency (EE) and Demand Response (DR), PG&E does not and cannot charge "basic customer service" activities as described above to these non-GRC accounts because expenditures from these accounts must have a direct relationship to the authorized programs (e.g., authorized EE or DR programs).[1288]

DRA asked PG&E to identify and provide citations to the specific Commission language that is the basis of PG&E's opinion that PG&E is prohibited from using funding from EE, DR or the Rate Design Window proceedings for the marketing, education and/ or outreach that PG&E is requesting for Customer Energy Solutions.[1289] Nothing in PG&E's response to that data request identified any specific language prohibiting PG&E from using the funding from Energy Efficiency, Demand Response or Rate Design Window proceedings for "basic customer service." On the witness stand, PG&E witness was unable to identify any such prohibition[1290]; certainly DRA is aware of none.

Therefore, DRA continues to recommend the Commission approve no incremental ratepayer funding for Provide Account Services in this GRC.

PG&E forecasts an incremental increase of $1.2 million in MWC IV, to support PG&E's anticipated expansion of customers participating in a Community Choice Aggregation (CCA)

[1285] Ex. 81 (DRA-13), p. 106 citing PG&E's response to DRA_082-Q26 see Atch02, tab 4-6, line 1.

[1286] Ex. 23 (PG&E-5 workpapers), p. WP 7-1, line 5.

[1287] D.12-04-045, p. 192-193; 2012 Cal. PUC LEXIS 193; D.12-11-015; 2012 Cal. PUC LEXIS 492; A.10-02-028.

[1288] Ex. 57 (PG&E-20), p. 6-4.

[1289] Ex. 238, Q/A. 2.

[1290] 21 RT 2258-2559 Brown/ PG&E.

program.[1291] DRA forecasts one incremental position at an increase of $150,000 to support increasing participation in CCA programs.[1292]

In September 2002, the California Legislature passed Assembly Bill (AB) 117, enabling Community Choice Aggregation (CCA) programs. Since the passage of AB 117, one CCA, Marin Energy Authority, has started providing generation service to customers. Marin Energy Authority (MEA), currently serves approximately 90,000 customers, and expects to expand to Richmond in 2013, to serve approximately another 100,000 customers.[1293]

Within PG&E's service territory, Clean Power SF is seeking to provide generation services to current PG&E customers. Clean Power SF is scheduled to start in October 2013, with participating customers paying extra monthly rates of $10.24-$29.78.[1294] Clean Power SF is expecting a participation rate of 90,000 customers in the initial roll out.[1295]

PG&E requested two positions for Account Services in its last GRC application. As PG&E stated then, "The 2 FTEs proposed for 2011 are required to manage the process and work the forecasted exceptions and data synchronization problems that are typical and expected to arise because of this kind of ongoing data exchange between PG&E and the city/county or designated third party. The number of FTEs needed could change depending on the number of communities that ultimately choose this option."[1296] Although the last GRC was settled and no exact expense for CCA participation identified, PG&E should have sufficient embedded funding to provide CCA customer service.

PG&E's Direct testimony forecasts a total CCA population of between 625,991 to 855,702, but offers no factual support for this assumed range.[1297] PG&E then uses a baseline,

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[1291] Ex. 23 (PG&E-5 workpapers), WP 7-24, line 5.

[1292] Ex. 81 (DRA-13), p. 107.

[1293] https://mcecleanenergy.com/, accessed 4/2/2013.

[1294] Roberts, Chris. Debate Over Rates Stalls SF Clean Power Plans, March 26, 2013. http://www.nbcbayarea.com/news/green/Debate-Over-Rates-Stalls-SF-Clean-Power-Plan-200124881.html, accessed 4/2/2013.

[1295] California Energy Markets, Feb. 15, 2013. No. 1219, p. 11.

[1296] Ex. 81 (DRA-13), p. 108 citing A.09-12-020, Ex. PG&E-4, p. 8-8, lines 27-34.

[1297] Ex. 22 (PG&E-5), p. 7-16; Ex. 23 (PG&E-5 workpapers), p. WP-7-24.

1 position for every 90,000 service agreements to claim it needs an increase of 8 full time employees.[1298]

PG&E introduced its actual forecasting method in Rebuttal testimony. PG&E said it was "…based on the number of Customer Service Agreements (SA) for each entity who requested that PG&E provide information while exploring CCA as an option, or who have publicly expressed an interest during the past two years in launching a CCA program."[1299]

PG&E's forecast is clearly overstated given that there is only one existing CCA to date: Marin Energy Authority. DRA forecasts a total CCA population of approximately 280,000, with the assumptions that there are 90,000 current customers in MEA, additional 100,000 Richmond customers joining MEA in 2013, and 90,000 Clean Power SF customers in 2013. DRA also uses the assumption that PG&E has embedded funding for two positions to support CCA customers, resulting in an incremental one position at the expense of $150,000 to provide service to the forecasted 280,000 customers.

5.7.1.2 MWC FK – Retain and Grow Customers

For 2014, PG&E forecasts a total of $3.2 million, or a 470% increase for Major Work Category Expenses FK – Retain and Grow Customers. This is an increase of $2.8 million over 2011 recorded expenses of $0.6 million[1300] DRA recommends using a five-year average of 2007-2011 recorded expenses for a 2014 forecast of $0.8 million, which is $0.2 million above 2011 recorded.[1301]

PG&E states that the requested level of funding is to provide an increased level of economic development project and support services, which will support the equivalent of 12 full-time employees and $1.5 million of economic development organization (EDO) membership dues.[1302] PG&E asserts that state cutbacks and local revenue shortfalls have reduced local government budgets including funds for local economic activities, and as a result there is a "…greater demand from communities for PG&E to provide a higher level of economic

[1298] Ex. 23 (PG&E-5 workpapers), p. WP 7-24, line 5.

[1299] Ex. 57 (PG&E-20), p. 6-7, lines 20-24.

[1300] Ex. 22 (PG&E-5), p. 7-21.

[1301] Ex. 81 (DRA-13), p. 109.

[1302] Ex. 22 (PG&E-5), p. 7-21, lines 16-20.

development services helping to drive business investment and job retention and creation in some areas in California most impacted by a slower economy."[1303]

PG&E has already been allocated funding for Local Government Partnerships and Statewide Institutional Partnerships through Energy Efficiency proceedings as set forth in the table below.

2007-2012 Authorized Budget for Government Partnerships
(in Thousands of Nominal Dollars)

	Authorized	Authorizing
Year	Budget	Decision/Advice Letter (AL)
2007	$ 41,207,443	AL 2704-G/2786-E, Attachment III - Program Summary Tables, D.05-09-043
2008	$ 41,207,443	AL 2704-G/2786-E, Attachment III - Program Summary Tables, D.05-09-043
2009	$ 47,087,824	AL 2967-G-A/3356-E-A - Attachment 1, D.08-10-027 (p. 18)
2010	$ 57,409,184	AL 3065-G-A/3562-E-A (p. 6, Table 2, p. 12, Table 12), D.09-09-047 (Appendix 1)
2011	$ 57,409,184	AL 3065-G-A/3562-E-A (p. 6, Table 2, p. 12, Table 12), D.09-09-047 (Appendix 1)
2012	$ 57,409,184	AL 3065-G-A/3562-E-A (p. 6, Table 2, p. 12, Table 12), D.09-09-047 (Appendix 1)

Source: See PG&E's response to DRA_082-07 Supp Atch01.[1304]

In addition, PG&E has been allocated funding through the most recent Energy Efficiency decision for Local Government Partnerships of approximately $50 million yearly for 2013 and 2014.[1305]

[1303] Ex. 22 (PG&E-5), p. 7-20 and 7-21, lines 29-31 and 6-8.

[1304] Ex. 81 (DRA-13), p. 110, Table 13-71.

[1305] D. 12-11-015, p. 104.

PG&E refers to the Ratepayer Impact Measurement (RIM) which it says shows the success of its GRC-funded Economic Development Program. According to PG&E, a "RIM test shows a positive Net Present Value result based on assumptions of successful attraction and retention of a minimum of two large customers (over 500 kW) and for medium-size customers (under 500 kW) per year based on forecast expenses for economic development …" PG&E points to its experience from 1996 to 2007 when it "helped to successfully attract and retain an average of 10 large customers and five medium-size customers per year."[1306]

PG&E's more recent customer retention statistics, however, show a decline. In 2011, a year when PG&E's Economic Development Program retained no large customers and no medium customers, PG&E still recorded $600,000 in expenses. In 2010, when PG&E says it retained 1 medium-sized customer, recorded expenses were $690,000. Evidently, recorded expenses for PG&E's efforts at retaining customers are not proportional to PG&E's success at doing so,[1307]

DRA, therefore, recommends using a five-year average (2007—2011) of recorded expenses for a 2014 forecast of $0.8 million.

5.7.1.3 MWC EZ – Manage Various Customer Care Processes

For Major Work Category EZ – Manage Various Customer Care Processes, PG&E forecasts a total of $31.6 million in expenses. This is a 166% increase over 2011 recorded expenses of $11.8 million. DRA recommends $11.8 million for Major Work Category EZ expenses in 2014.[1308]

PG&E's says its forecasted increase is due to several factors: (1) Electric and Gas Safety and Reliability Outreach; (2) Customer Rate Education; and (3) Customer Research, Planning and Product Development. Also included are Customer Access Charges which PG&E forecasts for 2014 to be a negative $0.8 million.[1309] This is an incremental decrease of $0.05 million beyond 2011 recorded of $0.75 million, which DRA accepts as it appears to be reasonable. Lastly, PG&E includes miscellaneous reductions of $1.4 million in Major Work Categories EZ

[1306] Ex. 22 (PG&E-5), p. 7-23, lines 16-21.

[1307] Ex. 81(DRA-13), p. 111.

[1308] Ex. 81 (DRA-13), p. 112.

[1309] Ex. 22 (PG&E-5), p. 7-11, Table 7-3, line 12.

and GM[1310] which DRA recommends be reallocated to Customer Rate Education, Major Work Category, EZ.

Electric and Gas Safety and Reliability Outreach

PG&E requests $5.4 million in 2014 for electric and gas safety and reliability outreach.[1311] DRA recommends no incremental ratepayer funding for PG&E's request.

PG&E says it plans to expand community-oriented and local outreach that will focus on general gas and electric safety and awareness and education. PG&E says that this expense has historically been charged to the operational lines of business.[1312] PG&E says that the activities it proposes here are separate and distinct from the customer outreach activities associated with utility infrastructure upgrade projects, which are charged to the operational lines of business. PG&E says it plans to focus outreach activities in schools, community events and other customer interactions in the field in order to increase general understanding of electric and gas safety practices.[1313] Examples of the type of situations PG&E forecasts for its expanded outreach are what to do in the event of downed power lines in areas with heavy vegetation, digging safely in agricultural areas, how to safely handle electricity and gas, and avoid hazards and deal with dangerous situations.[1314]

PG&E is currently, and has historically, provided education for these types of situations. As identified by PG&E in response to DRA discovery, "While CES (Customer Energy Solutions) has not historically funded electric and gas safety and reliability outreach, CES collaborates with other lines of business to educate the public about proper procedures to prevent unsafe situations such as fallen power lines and outage impacts by utilizing safety board demonstrations at various customer and community events. This type of outreach is funded by the other operational lines of business." Further PG&E states, "CES's request for Electric and

[1310] Ex. 22 (PG&E-5), p. 7-11, Table 7-3, line 11.

[1311] Ex. 22 (PG&E-5), p. 7-26.

[1312] Ex. 22 (PG&E-5), p. 7-26.

[1313] Ex. 22 (PG&E-5), p. 7-26.

[1314] Ex. 22 (PG&E-5), p. 7-27, Table 7-4, lines 2-3.

Gas Safety Reliability Outreach supports the Company's renewed focus on delivering a higher level of safe and reliable service to its customers."[1315]

PG&E currently has educational resources available at PGE.com for teachers and children regarding electricity and gas including hazardous situations,[1316] and uses bill inserts to inform customers about hazardous situations[1317] Thus, PG&E has embedded funding to educate customers on hazardous situations. To DRA's knowledge, PG&E has not reduced requested funding in the operational lines of business to offset its proposed increase for 2014 in Customer Energy Solutions. DRA recommends no incremental ratepayer funding for increased electric and gas safety and reliability outreach.

Customer Rate Education

For 2014, PG&E is requesting $18 million in funding for rate education and outreach.[1318] DRA recommends $7.0 million in expenses for 2014, equal to PG&E's recorded Peak Day Pricing (PDP) expenses charged to Major Work Category, resulting in an $11 million adjustment to PG&E's forecast plus escalation.

PG&E says that, at present, tariffed program outreach and education is funded through multiple means including the 2011 GRC, but also the Advanced Metering Infrastructure (AMI) decision, and the 2009 Rate Design Window.[1319] In the TY 2011 GRC, PG&E requested $23.7 million yearly for 2011-2013 for "Ongoing Support of PDP Program."[1320] Since the 2011 GRC was a "black box" settlement, no specific amount was earmarked for the ongoing support of Peak Day Pricing program, yet PG&E received funding and has embedded expenses in its 2011 recorded expenses for PDP in Major Work Category EZ of at least $7.0 million.[1321]

[1315] Ex. 81, (DRA-13), p. 113 citing PG&E's response to DRA_082-Q12.

[1316] http://www.pge.com/myhome/edusafety/teach/educationalresources/. Accessed April 8, 2013.

[1317]http://www.pge.com/en/myhome/myaccount/explanationofbill/billinserts/previous/index.page? Accessed April 8, 2013.

[1318] Ex. 22 (PG&E-5), p. 7-33.

[1319] Ex. 22 (PG&E-5), p. 7-27, lines 3-5.

[1320] Ex. 81 (DRA-13), p. 114, citing A.09-12-020, Ex. PG&E-4, p. 4-2, Table 4-1, line 5.

[1321] Ex. 22 (PG&E-5), p. 7-11, Table 7-3, line 7.

In this GRC, PG&E seeks $8.0 million[1322] to attract and retain customers to the SmartRate pricing plan. This request should be denied. PG&E was authorized $54.8 million through the original AMI decision to fund education and outreach activities of a critical peak pricing (CPP) rate or SmartRate.[1323] In the AMI decision, the Commission stated:

> We believe that PG&E conducted a comprehensive study of demand response using the statistical model developed in the SPP. With the aggressive and comprehensive educational advertising component in PG&E's CPP proposal, the customer participation level is likely to achieve the levels supported by PG&E's testimony. This CPP rate is a precursor of more accurate and timely rate designs that will be possible following the full implementation of AMI. A voluntary program will allow PG&E to build trust with the first eligible customers (those with AMI deployed) and subsequent rate design proceedings can build on the experience we derive from the voluntary CPP as we achieve full deployment. We have no record to consider either a mandatory or an opt-out program at this time.[1324]

As of the end of 2012, PG&E still had $7.1 million unspent dollars authorized for customer education for CPP rate enrollment. [1325] The intention of the funding was to "build trust with the first eligible customers and subsequent rate design." PG&E should already have achieved these goals with the current funding.

Nor has PG&E shown that it cannot use funding approved for 2014 from the Rate Design Window, Energy Efficiency or Demand Response decisions for SmartRate acquisition and associated ongoing activities. DRA asked PG&E to "…identify and provide citations to the specific Commission language that is the basis for PG&E's opinion that PG&E is prohibited from using funding from each of those (2009 RDW, DR and EE) decisions for the 2014 GRC marketing, education and/ or outreach that PG&E is requesting in PG&E-5…"[1326]

PG&E responded vaguely by saying, "Generally speaking the decisions approving the IOUs' portfolio applications for Energy Efficiency (D12-11-015), Demand Response

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[1322] Ex. 22 (PG&E-5), p. 7-31, line 2.

[1323] *See* Ex. 239 (PG&E Response to DRA-PG&E 183, Q. 15b, See Supp. 01).

[1324] D.06-07-027, p. 46.

[1325] Ex. 81 (DRA-13), p. 114 citing PG&E's response to DRA_183-Q15a see Supp01Atch01.

[1326] Ex. 238 (PGE Response to DRA_ 272)

(D12-04-045) and 2009 Rate Design Window (D.10-02-032) specify the purpose for which the funding is approved (or not approved) and such funding is typically limited to the purposes specified in the IOUs' applications." The only cited language was two Ordering Paragraphs from D.12-04-045, neither of which included any prohibition. In hearings, PG&E's witness said "I was not able to find any reference to prohibition in that decision."[1327]

In this GRC, PG&E's requests $6.65 million for ongoing maintenance and Peak Day Pricing (PDP) customer support and retention activities for LCI, Ag and SMB customers.[1328] This request should also be denied. The Decision in PG&E's Rate Design Window case proceeding specifically addressed that saying:

> This decision continues implementation of the Commission's policy to make dynamic pricing available for all electric customers by adopting and implementing default and optional critical peak pricing and time-of-use rates (together, referred to as Peak Day Pricing) beginning May 2, 2010 for Pacific Gas and Electric Company. This decision also adopts appropriate customer outreach and education activities and measures to ensure customer awareness and understanding of the new rates and options.[1329]

PG&E was granted $30 million in the 2009 Rate Design Window proceeding for implementation of Peak Day Pricing and, as of the end of 2012, $13.7 million was still unspent.[1330] PG&E also requested $23.7 million yearly for 2011-2013 for "Ongoing Support of PDP Program" in the 2011 GRC. In the 2011 GRC, PG&E said that "PG&E estimates that approximately 300,000 of the small and medium commercial and industrial and small agricultural customers will have sufficient interval meter data to default to new rates before October 2011 and will receive some direct outreach described in the (2009) RDW application."[1331] PG&E has requested that Rate Design Window funding period, already extended through 2014, be extended through 2016.

[1327] 21 RT 2559, Brown/ PG&E.

[1328] Ex. 22 (PG&E-5), p. 7-30, line 1.

[1329] D.10-02-032, mimeo, p. 2; 2010 Cal. PUC LEXIS 68.

[1330] Ex. 239, PG&E's response to DRA_183-Q15a see Atch01. PG&E has filed a Petition for Modification of the 2009 RDW decision which, if granted, would extend the funding period from 2014 to 2016. (21 RT 2577: 18-21, Brown/ PG&E.)

[1331] Ex. 81 9DRA 13,), p. 114, citing A.10-02-028, p. 5A-1.

In hearings, DRA asked if there had been fewer customers transitioning to Peak Day Pricing rates in 2011 than PG&E had forecasted in its Test Year 2011 application. PG&E's witness responded, "You know, I – I'm not familiar enough with the Peak Day Pricing proceeding and what was originally forecast."[1332] In fact, PG&E has had numerous delays in PDP implementation. With these delays, PG&E has sufficient embedded, unused funding to support its PDP plan for at least this GRC cycle.

Finally, in this GRC, PG&E requests $3.05 million for general rate communication and education for all customers.[1333] This request, too, should be denied. PG&E already has embedded funding for general rate communications and education through the 2011 GRC decision.

PG&E has also been authorized funding for marketing education and outreach through the Demand Response proceeding ($17.7 million for all customer classes both ongoing and implementation[1334] of DR programs for years 2012-2014),[1335] and the Energy Efficiency proceeding ($43.3 million[1336] for all customer classes both ongoing and for the implementation of EE programs 2013-2014), [1337]

In Rebuttal, PG&E says that "it does not have the discretion to use unspent non-GRC funds for activities that are not consistent with the purpose for which the funds were authorized."[1338] Considering the evidence throughout this case that Customer Care funds have been used to pay for projects completely outside of the Customer Care organization, this is a surprising argument for PG&E to make. In any event, though, PG&E has not shown any convincing evidence that the "three areas of focus: retention and acquisition of residential SmartRate customers; ongoing maintenance and customer support for non-residential PDP

[1332] 21 RT 2574 –2576, Brown/ PG&E.

[1333] Ex. 22 (PG&E-5), p. 7-31, line 3.

[1334] Ex. 81 (DRA 13), p. 115, citing PG&E's response to DRA_183-Q14 see Atch01.

[1335] D. 12-04-045, p. 192-193.

[1336] Ex. 81 (DRA 13), p. 115, citing PG&E's response to DRA_183-Q14 see Atch01.

[1337] Ex. 81 (DRA 13), p. 115, citing See PG&E's response to DRA_183-Q14c.

[1338] Ex. 57 (PG&E-20), p. 6-19.

customers; and general rate education for residential and non-residential customers[1339]" cannot be funded with the funding approved in the AMI decision, and the Energy Efficiency, Demand Response, and Rate Design Window proceedings and with the decision in PG&E's last General Rate Case.

Due to the several sources of non-GRC funding, delays in the implementation of Peak Day Pricing, and GRC embedded funding for marketing, education and outreach that PG&E has already been granted, DRA continues to recommend the Commission adopt DRA's forecast of $7.0 million plus for these activities.

Customer Research, Planning and Product Development

For 2014, PG&E requests a total expense of $3.1 million for its Customer Insight and Strategy Department. DRA recommends no incremental ratepayer funding for this Department beyond 2011 recorded expense of $2.0 million plus escalation.[1340]

For 2014, PG&E seeks a total expense of $ 2.8 million Pricing Products Department. DRA recommends no incremental ratepayer funding for these Departments beyond 2011 recorded expense of $1.4 million plus escalation.[1341]

Finally, for 2014, PG&E also seeks a total expense for the Policy and Integrated Planning Department of $2.6 million. DRA recommends no incremental ratepayer funding for this Departments beyond 2011 recorded expense of $1.2 million plus escalation.[1342]

In its TY 2011 GRC, PG&E requested an increase in funding for incremental staffing in the Customer Insight and Strategy Department saying that: "PG&E proposes to expand its data management staff by adding 2.5 FTE employees to manage the database, conduct statistical data analyses, and design statistical models of PG&E's customer data."[1343] In the TY 2011 GRC, PG&E also requested funding for the purchase of data and an additional information analyst saying that: "PG&E proposes to use direct outreach and to purchase external classification data

[1339] Ex. 57 (PG&E-20), p. 6-17.

[1340] Ex. 81 (DRA 13), p. 120.

[1341] Ex. 81 (DRA 13), p. 120.

[1342] Ex. 81 (DRA 13), p. 120.

[1343] Ex. 81 (DRA 13), p. 119, citing A. 09-12-020, Ex. PG&E-4, p. 4-18, lines 2-6.

(such as InfoUSA/Experian) to confirm the NAICS codes for these customers. In addition, PG&E proposes to hire one additional information analyst to record the new NAICS codes."[1344]

Now, in the 2014 GRC, PG&E forecasts an increase of $1.1 million over 2011 recorded expenses, "…for an additional database management position and costs to purchase external classification data to refresh customer information, in order to improve North American Industry Classification System coding of our business customers."[1345]

In the TY 2011 GRC, PG&E did not ask for incremental funding to support these positions due to certain expenses incurred in 2008 that will not be incurred in 2011,[1346] yet PG&E's recorded GRC labor expenses for the Customer Insight and Strategy Department in 2011 are less than half of the 2008 recorded expense. PG&E's Direct testimony does not substantiate this request for the same type of funding and DRA recommends no incremental ratepayer funding beyond 2011 recorded expenses plus escalation of $2.0 million.

PG&E's incremental expense requests for the Pricing Products Department and the Policy and Integrated Planning Departments have been increasingly funded through non-GRC sources of funding as Table 13-75 shows. PG&E continues to be allocated funding through the EE and DR proceedings which it has chosen to use to fund the Pricing Products and Policy and Integrated Planning Departments. Therefore, DRA recommends no incremental ratepayer funding for the Pricing Products and Integrated Planning Departments beyond 2011 recorded expense of $2.6 million plus escalation.[1347]

Capital

For Major Work Category 28 EV – Station Infrastructure, PG&E forecasts capital expenditures of $0.3 million in 2012 and $0.8 in 2013.[1348]

DRA recommends using PG&E's recorded expenditure of $44 thousand for 2012, and forecasts $112 thousand for 2013.[1349]

[1344] Ex. 81 (DRA 13), p. 119, citing A. 09-12-020, Ex. PG&E-4, p. 4-17, lines 19-24.

[1345] Ex. 22 (PG&E-5), p. 7-36, p. 7-36, lines 28-31.

[1346] Ex. 81 (DRA 13), p. 120, citing A. 09-12-020, Ex. PG&E-4, 4-18, lines 19-26.

[1347] Ex. 81, p. 120.

[1348] Ex. 22 (PG&E-5), p. 7-43, Table 7-9.

[1349] Ex. 81, p. 122.

PG&'s Direct testimony provides no explanation of planned projects or how it forecasted 2012 or 2013 capital expenditures. DRA's forecast is derived using the percentage of PG&E's 2012 forecast which it actually spent (13.5%) , and applying that (13.5%) to PG&E's 2013 forecast of $0.8 million to reach DRA's forecast of $0.1 million.

In Rebuttal, PG&E says it actually spent $1.1 million on this project in 2012, but apparently recorded part of its 2012 spending somewhere else.[1350] Again, this information comes too late for DRA to verify it and DRA continues to recommend that the Commission adopt DRA's forecast instead.

5.8 Customer Retention

PG&E requests authorization to book Customer Retention Program expenses above-the-line starting in 2014, in Major Work Category FK – Retain and Grow Customers. PG&E forecasts $1.5 million of expenses in 2014. DRA recommends no ratepayer funding.[1351] DRA has historically supported the concept of municipalization and stresses that ratepayers should not have to fund utilities' efforts to block or oppose reasonable municipal utility projects. While PG&E's recorded expenses in MWC FK are fairly small, PG&E's parent corporation has spent far more money on its efforts to fight publicly-owned power. In 2006, PG&E Corp. spent more than $11 million to convince ratepayers in Yolo and Sacramento Counties to vote down an annexation proposal that would have extended the Sacramento Municipal Utility District's (SMUD) service territory to include the Yolo County cities of West Sacramento, Davis and Woodland.[1352]

In its Direct Testimony, PG&E says it is "… asked to provide information and analysis when an elected official, city or agency staff or an external advocates, proposes to the city or agency that it enter the retail electricity distribution business. Other elected officials or interested community members approach PG&E with urgent questions about these proposals, to

[1350] Ex. 57, p. 6-23.

[1351] Ex. 81, p. 124.

[1352] http://www.newsreview.com/sacramento/content?oid=1040018. Accessed, April 9, 2013.

which PG&E must respond."[1353] PG&E also says its "customer retention activities benefit customers by providing accurate information and analysis to enable well-informed decisions."

But DRA notes that in the recent past, there has been considerable dispute over the accuracy of the information and analysis PG&E provides. For example, in the campaign leading up to the defeat of Proposition 16, the League of Women Voters said that "PG&E's campaign tries to make voters believe that if local governments choose to buy electric power from any source other than PG&E, the likely result is either higher rates for that service or the local government raising local taxes or floating bond measures to meet escalating costs. But under current law, local governments cannot either raise any taxes or pass bond measures without going to the voters for approval. Neither local government power providers nor CCAs are profit-making enterprises that need to satisfy shareholders. If communities choose to obtain their energy from publicly owned utilities or CCAs, it is because they want to obtain it at lower cost, or from "greener" sources, such as renewable or less polluting energy sources, than PG&E offers."[1354]

In 2010, PG&E Corp. spent $43 million on Proposition 16 that would have required two-thirds voter approval for local municipalization. Proposition 16 failed to pass by a small margin.[1355] While PG&E Corp. is free to pursue such expensive efforts, these activities should not have to be funded by its ratepayers. DRA therefore recommends denying all costs for customer retention.

5.9 Information Technology Programs

5.9.1 Expense

For 2014, PG&E forecasts $8.2 million in expenses to support PG&E's forecasted Customer Care IT projects.[1356] DRA recommends $3.5 million in expenses for 2014, an adjustment of $4.7 million to PG&E's 2014 forecast.

PG&E forecasts were derived using PG&E's Concept Estimating Tool. The areas in dispute are discussed below.

[1353] Ex. 22 (PG&E-5), p. 8-2.

[1354] See Ex. 241.

[1355] http://venturebeat.com/2010/06/09/pge-loses-its-46m-prop-16-battle-in-california-a-win-for-grid-innovation/. Accessed, April 9, 2013.

[1356] Ex. 22 (PG&E-5), p. 9-14.

5.9.1.1 Customer Interaction and Relationship Management

PG&E forecasts total expenses of $9.0 million, ($3.0 million in 2014, $3.0 million in 2015 and $3.0 million in 2016,)[1357] for the implementation of the Customer Interaction and Relationship Management Project. DRA recommends no ratepayer funding for this project as explained below in Section 5.9.2., Capital.

5.9.1.2 Customer Self-Service and Energy Management Enhancements

PG&E forecasts total expenses for 2014-2016 of $3.0 million, $0.8 million in 2014, $1.2 million in 2015 and $1.0 million in 2014.[1358] DRA reviewed PG&E's Customer Self-Service and Energy Management Enhancements Project. DRA accepts the project is reasonable, if the expense level reduced by 14%, or $0.21 million, based on DRA's concerns with forecasts of IT projects calculated with the "Concept Estimating Tool," as discussed in Section 7 of this Opening Brief. This leads to a 2014 forecast of $0.69 million.[1359]

5.9.1.3 Interval Data Processing and Exceptions Management

PG&E forecasts total expenses of $4.8 million for years 2014-2016, $1.8 million in 2014, $1.5 million in 2015 and $1.5 million in 2016.[1360] DRA has reviewed PG&E's the project and accepts the project is reasonable if the: 1) yearly capital expenditures are normalized for a 2014 expense forecast of $1.6 million; and (2) the expense level is reduced by 14%, or $0.46 million, based on DRA's concerns with forecasts of IT projects calculated with the "Concept Estimating Tool," as discussed in Section 7 of this Opening Brief. This leads to a 2014 estimate of $1.14 million.[1361]

[1357] Ex. 23 (PG&E-5 workpapers), p. WP 9-34.

[1358] Ex. 23 (PG&E-5 workpapers), p. WP 9-40.

[1359] Ex. 110 (DRA Errata), p.127

[1360] Ex. 23 (PG&E-5 workpapers), p. WP 9-45.

[1361] Ex. 110 (DRA Errata), p. 128.F

5.9.1.4 Optimizing Time to Market for Rates

PG&E forecasts total expenses of $2.0 million dollars for years 2015-2016, $1.0 million in 2015 and $1.0 million in 2016.[1362] This project is not part of PG&E's request for the 2014 revenue requirement, so DRA has not included any expenses for its 2014 forecast.

5.9.1.5 Meter Management

PG&E forecasts total expenses of $1.6 million all to be spent in 2014.[1363] DRA has reviewed PG&E's Interval Data Processing and Exceptions Management Project and accepts the project if the 1) yearly capital expenditures are normalized for the 2014-2016 GRC cycle, for a 2014 expense forecast of $0.53 million; and (2) the expense level is reduced by 14%, or $0.45 million, based on DRA's concerns with forecasts of IT projects calculated with the "Concept Estimating Tool," as discussed in Section 7 of this Opening Brief.

5.9.2 Capital Expenditures

PG&E requests $16.0 million in 2012, $13.8 million in 2013 and $33.4 million in 2014 for its Customer Care IT Programs. PG&E's 2014 capital expenditure forecast is 329% greater than the 2011 recorded amount of $7.8 million.[1364] DRA recommends the Commission adopt: (1) PG&E's recorded capital expenditures of $18.3 million for 2012, an increase of $2.3 million to PG&E's request; (2) $11.6 million for 2013, and (3) $10.5 million for 2014. The reasons for the differences are discussed below.

Customer Care IT capital expenditures in 2012 and 2013 include Contact Center Refresh and Meter to Cash Enhancements.

5.9.2.1 Customer Care Technology Projects

For 2013, PG&E requests $13.8 million for the completion of several smaller scale projects and the Contact Center Refresh. DRA accepts PG&E's forecast with the inclusion of DRA's global recommendation to reduce PG&E's forecasts of IT projects which are calculated using the "Concept Estimate Tool" by 14%. For 2013, this results in a forecast of $11.9 million.

[1362] Ex. 22 (PG&E-5), p. 9-12, lines 27-28.

[1363] Ex. 22 (PG&E-5), p. 9-13, lines 13-14.

[1364] Ex. 22 (PG&E-5), p. 9-1 and 9-2, lines 20-25 and 1-2.

All projects included in PG&E Customer Care Technology Projects are forecast to be completed in 2013; so there are no capital expenditures beyond then.

5.9.2.2 Customer Interaction and Relationship Management

PG&E requests capital expenditures for the implementation of the Customer Interaction and Relationship Management project of $12.0 million in 2014, $15.0 in 2015 and $10.0 million in 2016 for a total project capital forecast of $37.0 million. DRA recommends zero funding for this project.

PG&E's Direct testimony and workpapers provide little insight into how PG&E derived its forecasts, and the planning status of the project. DRA, therefore asked PG&E to provide:

> (e) Copies of all analyses, studies, (and) assessments in determining the need for the proposed IT project.
>
> (f) Copies of all supporting documents and calculations in determining the forecasted capital expenditures and expenses.[1365]

PG&E responded to question (e) by providing DRA with a five slide PowerPoint presentation, including a high level identification of the project with no numbers, or vendor quotes.[1366] The lack of substantial analysis, no identified vendors or software, leads DRA unable to verify or accept PG&E's $37.0 million forecast.

PG&E responded to question (f) by referring DRA to the Concept Estimating Tool.[1367] The information provided in the Concept Estimating Tool provides little if any information as to the validity of PG&E's estimates. PG&E does include cost benefits for the implementation of the Customer Interaction and Relationship Management Project. But in response to DRA discovery regarding realization of benefits PG&E stated:

> PG&E tracks project benefits on an on-going basis against certain Company-wide metrics, such as safety and reliability, customer satisfaction and affordability. In addition, PG&E implemented a new project delivery methodology in August 2011 to ensure that (1) IT projects are closely aligned to both line of business and IT goals; (2) the project is set up for success; and (3) the benefits of the project are well defined and will be realized when the project is deployed. Prior to approval, each technology project proceeds

[1365] Ex. 81 (DRA 13), p. 130, citing PG&E's response to DRA_096_Q01e and Q01f.

[1366] Ex. 81 (DRA 13), p. 115, citing PG&E's response to DRA_096_Q01(e)_Atch01.

[1367] Ex. 81 (DRA 13), p. 115, citing PG&E's response to DRA_096_Q01(f).

> through the IT governance stage-gates. As part of the initial stage-gate, the IT Business Technology Lead must present the project benefits. The Business Technology Lead then confirms that the expected benefits will be achieved during stage-gate 4 (deploy phase).[1368]

Although PG&E's forecasted benefits appear good on paper, PG&E offers no assurance that ratepayers funding IT projects will actually receive cost benefits, resulting in an empty promise to ratepayers. Due to the Customer Interaction and Relationship Management Project being in the very early planning stage and the lack of information validating the project, DRA recommends no ratepayer funding.

5.9.2.3 Customer Self-Service and Energy Management Enhancements

For its Customer Self-Service and Energy Management Enhancements project, PG&E requests a total of $15.0 million in capital expenditures, $4.0 million in 2014, $6.0 million in 2015, and $5.0 million in 2016.[1369] DRA reviewed PG&E's Customer Self-Service and Energy Management Enhancements Project and accepts the project with the inclusion of DRA's global recommendation to reduce PG&E's IT forecasts calculated using the "Concept Estimate Tool." DRA's 14% reduction leads to a 2014 forecast of $3.44 million.[1370]

5.9.2.4 Interval Data Processing and Exception Management

For its Interval Data Processing and Exception Management project, PG&E forecasts total capital expenditures of $22.2 million, $16.0 million in 2014, $4.2 million in 2015 and $2.0 million in 2016.[1371] DRA accepts the project as reasonable if (1) yearly capital expenditures are normalized for a yearly capital forecast from 2014-2016 of $7.4 million, and (2) the total forecast is reduced by 14% consistent with DRA's global recommendation to reduce PG&E's forecasts of IT projects calculated using the "Concept Estimating Tool." This leads to a 2014 forecast of $6.36 million.

[1368] Ex. 81 (DRA 13), p. 131, citing PG&E's response to DRA_096_Q12.

[1369] Ex. 22 (PG&E-5), p. 9-8, lines 29-32.

[1370] Ex. 110 (DRA Errata), p. 131.

[1371] Ex. 22 (PG&E-5), p. 9-10, lines 29-32.

5.9.2.5 Meter Management

For its Meter Management project, PG&E forecasts $0.9 million. DRA accepts the project as reasonable if (1) yearly capital expenditures are normalized for a yearly capital forecast from 2014-2016 of $0.3 million, and (2) the total forecast is reduced by 14% consistent with DRA's global recommendation to reduce PG&E's forecasts of IT projects calculated using the "Concept Estimating Tool." This leads to a 2014 forecast of $258,000.[1372]

5.9.2.6 Optimizing Time to Market for Rates

PG&E forecasts total capital expenditures of $12 million, $0 in 2014, $6.0 million in 2015, and $6.0 million in 2016.[1373] This project is not part of PG&E's request for the 2014 revenue requirement.

5.10 SmartMeter™ Program

As part of this Application, PG&E asks the Commission to authorize it to (1) close the SmartMeter balancing accounts, benefits realization mechanism, and Meter Reading balancing account on Dec. 31, 2013; (2) incorporate in the 2014 GRC forecast Smart Meter program benefits; (3) recover ongoing SmartMeter operating costs; and (4) eliminate and/or replace SM reporting requirements.[1374]

PG&E says that:

> With the closure of the Smart Meter Balancing Accounts, recovery of the ongoing capital-related revenue requirements associated with past Smart Meter Program deployment capital costs will now occur in PG&E's GRCs.[1375] In this 2014 GRC, the beginning-of-year 2014 plant, depreciation reserve, and base rate amounts include the amounts associated with Smart Meter Program deployments capital costs incurred since the Program's inception through 2011 and forecast to be incurred in 2012 and 2013. Such costs are thereby consolidated with the 2014 GRC capital request

DRA recommends the Commission: (1) allow PG&E to recover capital-related revenue requirements associated with the deployment of the Smart Meter Program up to the authorized

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[1372] Ex. 110 (DRA Errata), p. 133.

[1373] Ex. 22 (PG&E-5), p. 9-12, lines 27-29.

[1374] Ex. 22 (PG&E-5), p. 10-4.

[1375] Ex. 22 (PG&E-5), p. 10-3 to 10-4, lines 26-27 and line1.

amount of $2.306 billion less $10 million in shareholder funding (as adopted in D.06-07-027); (2) continue the reporting requirements until PG&E has fully deployed its Smart Meter Program.[1376]

It is DRA's understanding from discovery that, "At this time, PG&E has no plans to update the record in this 2014 GRC to replace the forecast SmartMeter™ Program 2012 and 2013 plant amounts (shown in the workpapers supporting Chapter 9, Electric, Gas, and Common Plant, in the Results of Operations Exhibit (PG&E-2)) with the actual recorded amounts."[1377]

DRA's recommendation seeks, in part, to ensure PG&E does not recover in this GRC capital-related revenue requirements associated with the deployment of the Smart Meter Program beyond the Commission authorized amounts. PG&E states "As of January 31, 2013, PG&E's total SmartMeter™ Program expenditures exceed(ed) the authorized amount. Although Decision 06-07-027 would allow PG&E to seek recovery of excess costs, PG&E does not at this time seek to recover these additional costs."[1378] To approve capital-related revenue requirements associated with the deployment of the Smart Meter Program above the current authorized amount would be premature, as PG&E has not requested or been approved recovery of additional costs.

Related to the current recorded amounts charged to Smart Meter Program deployment, DRA is concerned that an independent audit has yet to be conducted as ordered by the Commission[1379] and recommends the Commission require the completion of an audit of PG&E's Smart Meter Program.[1380] The audit would be to "… ensure proper booking and allocation of costs and benefits related to PG&E's SmartMeter program and evaluate whether PG&E's internal cost management guidelines are adequate to ensure that all labor and nonlabor costs are properly booked to the SmartMeter balancing account."[1381]

[1376] Ex. 22 (PG&E-5), p. 10-4, lines 9-14.

[1377] Ex. 81 (DRA 13), p. 135, citing PG&E's response to DRA_Oral031-01.

[1378] Ex. 81 (DRA 13), p. 115, citing PG&E's response to DRA_Oral031-01.

[1379] D.11-05-018, OP 19.

[1380] Ex. 110 (DRA Errata), p. 135-136.

[1381] D.11-05-018, mimeo, p. 18.

Once PG&E's Smart Meter Program has been fully deployed, apart from the Opt-Out customers, DRA accepts PG&E's proposal to cease providing annual reports on the AMI-enabled DR till 2019 as ordered by the Commission.[1382] DRA recommends that the Commission require PG&E to include information, to the extent it is pertinent, in PG&E's annual load impact filings and in future requests for Demand Response program approval and cost recovery. DRA's proposal seeks to consolidate the DR reporting requirements once Smart Meters are fully deployed.

PG&E requests that ongoing costs related to the Smart Meter Opt-Out Program be recovered in base rates in the 2014 GRC.[1383] As previously noted DRA recommends that the Commission adopt a one-way balancing account for all of PG&E's requested Opt-Out related expenses, capital expenditures, and revenues.[1384]

5.11 Accessibility Improvements

DRA has no comment on this issue at this time.

6 ENERGY SUPPLY

PG&E's Energy Supply group (ES) manages all of PG&E's power generation, power procurement, energy trading, scheduling and related administration. ES has three main divisions: (1) Nuclear Generation, (2) Energy Procurement and (3) Power Generation. ES also has a small unit known as the ES Policy and Process Standards that support the activities of the three main divisions. ES Nuclear Generation group manages PG&E's only nuclear facility, the Diablo Canyon plant, Energy Procurement executes and administers PG&E's generation contracts with third parties, and Power Generation operates all of PG&E-owned non-nuclear facilities, including several fossil fuel plants procured within the last decade when PG&E returned to procurement after the electricity crisis[1385].

[1382] D.09-03-026, OP 10.

[1383] Ex. 22 (PG&E-5), p. 10-2, lines 5-9.

[1384] Ex. 81 (DRA-13), p. 136.

[1385] Ex. 24 (PG&E-6), p.1-9; D.04-12- 048; D. 06-11-048 Approving Results of Long-Term Request for Offers

DRA recommends that the Commission authorize $563.389 million for ES O&M, which reduces PG&E's $790 million request by about $156.28 million. This reduction consists of $92.764 million dollars from the nuclear generation O&M ($92.717 million) and Hydroelectric O&M ($47 million). All other ES MWCs, mainly for fossil and other renewable resource generation, energy procurement administration and energy supply ratemaking were reduced a modest $16 million despite the Liberty Consultants concern that the ES's O&M request "raises questions about how funding levels have been determined and validated"[1386].

PG&E's O&M request and DRA's corresponding recommendation for ES are as follows:

(1) $415.5 million for Nuclear Operations O&M (DRA - $285 million)

(2) $191.144 million is for Hydroelectric O&M (DRA - $143 million)

(3) $54.8 million Fossil & Other Generation (DRA - $46.606 million)

(4) $58.8 million Energy Procurement Administration (DRA - $50.606 million)

ES operations and maintenance (O&M) expenses are divided into thirty-two (32) major work categories (MWC) that consist of similar types of work expensed in SAP dollars. Consequently, DRA's recommendations correspond to ES MWC and are also expressed in SAP dollars. SAP dollars include certain labor-driven adders such as employee benefits and payroll taxes.

6.1 Policy and Introduction

The Commission decision in PG&E's TY 2011 General Rate Case adopted a settlement agreement. That settlement agreement resolved all Energy Supply issues with a revenue requirement that was less than PG&E had forecast in its Application. The settlement did not establish specific dollar amounts for each Major Work Category, so there are no "Commission authorized" amounts for individual MWCs. PG&E, however, did "impute" or earmark" dollar amounts for the MWCs at issue here.[1387]

[1386] Ex. 24 (PG&E-6), p.2-4

[1387] 25 RT 3084, Halpin/PG&E.

6.2 **Hydro Operations Costs**

Hydroelectric power facilities are ES's largest investment after the Diablo Canyon nuclear plant. PG&E hydroelectric generating assets consist of 68 power houses with 109 generating units[1388], 171 dams, 368 miles of conveyances, water storage, switching centers and 48 penstocks that stretch over 86 miles[1389]. The dams and their related appurtenances are some of the most inspected of PG&E's power generation facilities, in part because they are "doubly-regulated" by the FERC and the Division of Safety of Dams (DSOD)[1390]. "Annual FERC and/or DSOD inspection are required of each dam.[1391]" Many of the dams are subject to FERC's five-year Part 12D safety inspection[1392]. In addition to these regulatory oversights, "[ES's] Power Generation makes extensive use of consultants and outside panels to review its facilities and processes"[1393]. As such, these facilities do not require a heightened level of anxiety and funding in this GRC out of concerns for employee and public safety, beyond what has normally been the case. The O&M processes already in place were so adequate to ensure the safe and secure operation of the hydroelectric facilities that Liberty Consultants concluded:

> The underlying processes are extensive and large dams do not lack for attention …
>
> …
>
> There is no question as to the effectiveness of dam safety management in Power Generation. The processes in place are extensive, and have grown more rigorous and testing with time.

(Liberty Consultants Report, p.66.)

Notwithstanding these facts, PG&E claims that the main drivers for ES request of 43% (percent) increase in O&M for TY 2014 over TY 2011 expenses are "Management effort and associated Facility safety and Penstock programs in response to our focus on public and

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[1388] Ex. 24 (PG&E-6), p.2-4

[1389] Liberty Consultants Report, p.2.

[1390] Id.

[1391] Ex. 24(PG&E-6), p.2-29

[1392] Id.

[1393] Liberty Consultants Report, p.66.

employee safety"[1394] and "associated FERC licensing conditions in recently issued licenses"[1395]. These claims have not been and cannot be justified on the basis of the testimony and evidence submitted in this TY 2014 GRC.

6.2.1 Expense

PG&E forecasts $191 million for its hydroelectric operations for test year 2014, a 43% (percent) increase over 2011 recorded adjusted expenses of $133.028 million. This forecast combines Base Work, which are day-to-day, year-in-year-out routine work, and Non-Base work, which are projects that are unique in nature, and are not repeated every year. The forecast also includes work that PG&E initially proposed in TY 2011 GRC, but either deferred or rescheduled. In many instances, PG&E reallocated funding authorized for Hydro work to lines of business outside its Hydro unit. PG&E TY 2014 application also includes a ratemaking proposal to establish a two-way balancing account to manage capital and expenses for tis Hydro-operations.

ES Hydroelectric Operations perform start-ups and shut-downs, manage generation output and water flows, read instruments, records, monitor and track performance and schedule maintenance. These O&M activities are expensed in thirteen (13) MWCs for test year 2014 GRC. However, DA's recommendations only reduce six (6) of these MWCs. The six at issue are: (1) MWC AB – Support ($3.064 million), (2) MWC AX – Maintain reservoirs, Dams and Waterways ($36.813 million), (3) MWC KJ – Regulatory/License Compliance ($47.902 million), (4) MWC KI – Maintain Hydro Structures, Roadways and Infrastructure ($14.625 million), (5) MWC KG – Operate Hydro-Generation ($51.507 million), (6) MWC JV Maintain Information Technology Apps & Infra ($3.350 million).

DRA adopted PG&E's recommendation for the following seven (7) MWCs:

(1) MWC AK – Manage Environmental Operation	$2.4 million
(2) MWC AY – Habitat and Species Protection	$0.192 million
(3) MWC BC – Perform Reimbursable Work for Others	($0.222 million)
(4) MWC EP-Manage Property & Buildings	$1.049 million

[1394] Ex. 24 (PG&E-6), p. 27.

[1395] Id., p. 2-7.

(5) Implement Environmental Projects	$0.373 million
(6) Manage Environmental Remediation	$0.10 million
(7) Maintain Hydro-generating Equipment	$30.037 million

Thus, notwithstanding the clear and convincing evidence that the hydroelectric facilities are safe and secure, DRA did not reduce PG&E's estimate for Maintaining Hydro-Generating Equipment at $30.037 million, among several other MWCs.

6.2.1.1 MWC AB – Support ($3.064 million)

PG&E's $3.064 million forecast for MWC AB-Support is 118.23% more than its 2011 recorded adjusted expense of $1.404 million despite this work category being one that even PG&E did not attempt to justify on the basis of safety and security. DRA's forecast uses the 2011 recorded adjusted figure of $1.404 million.

PG&E describes MWC AB as costs PG&E incurs to support the Land Conservation Commitment (LCC) to preserve approximately 140,000 acres of its watershed lands in the Sierra Nevada, Cascades, and North Coast Range mountains for the benefit of future generations of Californians[1396]. This obligation apparently arose out of the Bankruptcy Settlement Agreement and Stipulation and required the establishment of the Pacific Forest and Watershed Lands Stewardship Council (Stewardship Council) to act as an advisory body to oversee development and implementation of a Land Conservation Plan (LCP) and the Youth Investment Initiative. "The Stewardship Council receives $10 million annually for 10 years (2004 through 2013) from PG&E, with $70 million funding the LCP and $30 million going towards the Youth Investment Initiative."[1397]

It is unclear from PG&E's description of MWC AB-Support exactly what costs PG&E is supposed to incur in this work category. Rather than present a clear picture of the work items that are included in this MWC PG&E obscures the fact by first describing what costs the Stewardship Council would be responsible for, which has no bearing on the costs that PG&E is

[1396] Ex. 24 (PG&E-6), p. 2-91.

[1397] Id.

expected to incur. The closest that PG&E comes to presenting kind of work that is usually included in MWC AB-Support is as follows:

> On May 3, 2007 the Commission authorized the creation of the LCP implementation Account clarifying the requirement of the Bankruptcy Settlement Agreement and Stipulation with regard to certain LCP implementation costs and authorizing PG&E to recover costs associated with the regulatory review and approval of transactions necessary to implement the LCP, including those costs incurred by PG&E for outside consultants or experts necessary to assist in the preparation or processing of the Section 851 or FERC applications and components thereof; costs incurred by the CPUC in the review and approval of the Section 851 applications and ordinarily passed through for reimbursement from PG&E; costs incurred by FERC in the review and approval of the proposed applications and filings at FERC required to implement the LCP and ordinarily passed through for reimbursement from PG&E; and, any other similar items related to the development of an d regulatory review and approval of applications for transactions necessary to implement the LCP that are not explicitly delineated in the Bankruptcy Settlement Agreement and Stipulation or authorized in PG&E's GRC.

(Ex. 24, PG&E-6, p.2-92.)

The LCC support costs authorized for PG&E in 2011 was $6.495 million, but the recorded adjusted cost for that year was $1.404 million. This amount was consistent with the recorded adjusted costs for each year from 2007 through 2010[1398] , which averaged $1.320 million.

Although the forecast for MWC AB-Support is "based on an expected level of transactions over the GRC period"[1399], PG&E concedes that it does not have not yet have the documentation "to develop an accurate estimate…"[1400] for this work category. It is a mockery of the GRC process for PG&E to increase a work category by a sum that is more than 100% of any adjusted recorded costs for that category in five of the last six years, while asserting that it does not have the information to support such an exaggerated forecast. This is especially true when PG&E also concedes that "[n]o new type of work is forecast in this MWC."

[1398] Ex. 79 (DRA-11), p. 21. [2007 ($1.601); 2008 ($1.201); 2009 ($1.405); 2010 ($1076)]

[1399] Ex. 24 (PG&E-6), p. 2-93.

[1400] Id.

In subsequent discovery, PG&E explained what it meant by "[n]o new type of work is forecast in this MWC" as follows:

> PG&E means by its statement that 'No new type of work is forecast in this MWC' that the body of work within the MWC is similar to the work contained in the 2011 and earlier GRCs. The increased 2014 forecast for the Land Conservation Support is to continue an ongoing effort as described above.

(Ex. 79, DRA-11, p.22.)

There is no dispute then that PG&E's forecast for MWC AB-Support is not for incremental internal work as PG&E had partly claimed, but "for routine and on-going activities that do not require additional funding."[1401] Therefore the Commission should support DRA's recommendation for $1.404 million funding for this work category.

6.2.1.2 MWC AX – Maintain Hydro Reservoirs, Dams and Waterways [$36.813 Million]

PG&E's request for $36,813 million to maintain Hydro reservoirs, dams and waterways is the second largest request for a major work category in the Hydro unit. This suggests that PG&E has identified a significant amount of work that needs additional inspection and restoration, when in fact, these facilities are the safest and most inspected of Power Generation facilities.

Liberty Consultants was most impressed by the condition of PG&E's Hydro facilities and the level of oversight that has been focused on it, including multi-jurisdictional regulation by FERC and DSOD, as well as outside consultants and PG&E's own employees.

> The processes in place are extensive, and have grown more rigorous and testing with time.
>
> …
>
> Overall dam safety has increased as a result, it is strong and growing stronger.

(Liberty Consultant's Report, p.66.)

PG&E had the same number of dams in 2011 as it does now, and in fact noted that "no new type of work is forecast in this MWC."[1402] Nevertheless, PG&E's TY 2014 forecast for

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[1401] Ex. 79 (DRA-11), p. 22.

[1402] Ex. 24 (PG&E-6), p.2-73.

MWC AX is $15.056 million on 69.20 percent over TY 2011 recorded adjusted expenses of $21.757 million. PG&E provides no justification or rationale for the $15.056 million incremental cost. Neither PG&E's workpapers nor its testimony describes any of the projects that needs to be done in detail.

> In discovery, DRA asked PG&E to "provide a detailed breakdown of the calculation of the forecasted increase of $15.056 million (i.e., the calculation of each individual line item estimate included in the increase) and the supporting documentation to substantiate the projects that caused the increase in expense."[1403] PG&E's response referred DRA back to PG&E's workpapers.

(Ex. 79, DRA-11, pp.23-24.)

PG&E's workpapers do not contain the information. Therefore, PG&E has failed to meet its burden of establishing the need for incremental expenses for MWC AX, and the Commission should adopt DRA's recommendation of 2011 adjusted amount of $21.757 million. The 2011 recorded adjusted amount was the largest amount PG&E had spent on MWC AX since 2007. The corresponding figures from 2007 through 2010 were as shown in the table below.

Table 11-10[1404]
PG&E's 2007-2011 Authorized vs. Recorded Hydro Operations Expenses
2012 Forecasted vs. Recorded Expenses
and 2014 Forecast for Major Work Category AX
(In Thousands of Dollars)

		2007	2008	2009	2010	2011	2012	2014
AX	Authorized	$18,822	$19,388	$19,954	$20,520	$25,898	--	--
	Recorded	$14,980	$15,709	$14,722	$17,757	$21,757	$23,037	--
	Forecasted	--	--	--	--	--	$24,123	$36,813

[1403] DRA-PG&E-TLG-101, Q. 7a.

[1404] Ex. 79 (DRA-11), p. 24. [Source: Authorized 2007-2010 data from Master Data Request, Chapter 24 Q.1. Authorized 2011 data from PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018. Recorded 2007-2011data from Ex. PG&E-6, Chapter 2, p. WP 2-1. Recorded 2012 data from PG&E's response to DRA data request DRA-PG&E-108-CKT. Forecasted 2012 and 2014 data from Ex. PG&E-6, Chapter 2, p. WP 2-1.]

Liberty Consultant noted that there was a deliberate spike in Hydro work after the San Bruno accident in 2010.

> The risk of dam or other structural failure was identified as an enterprise risk in 2007. It does not appear that much was done as a result until such risk moved up in priority after the San Bruno incident. After that, there were at least three significant sep escalations in the program, as well as a continuing growth in momentum. … In late 2011, the program was expanded once again.

(Liberty Consultants Report, p.65.)

There is simply no new need for massive incremental investment in routine Hydro inspection and maintenance work, at PG&E. Post San Bruno escalations have already raised these investments beyond industry levels without justification. Therefore, the Commission should adopt DRA's recommendation.

Another interesting element of MWC AX increases is how similar it is to MWC KI from the last GRC which PG&E justified largely on similar grounds but subsequently classified as low priority work and transferred the funds for the category outside Hydro to do other work, yet unaccounted.

> PG&E ratepayers should not be required to fund PG&E's routine and on-going maintenance work twice because PG&E's management decided to defer the work, underspent in MWC AX, and reallocated the funding outside of its Hydro operations, or because PG&E did not incorporate historical embedded cost for on-going and routine projects into its Test Year forecast.[1405] PG&E had 2012 and has 2013 to complete these proposed on-going or deferred projects before the 2014 Test Year.

(Ex. 79, DRA-11, p.27.)

Reports of the stellar condition of Hydro facilities, coupled with above industry average FOF and the absence of a FERC inspection report supporting the need for additional work, make MWC AX a likely source of funds for other projects PG&E may later consider higher priority. The Commission has a rule about deferred maintenance in TY GRC.

> For us to authorize Edison's recovery of deferred maintenance expense would establish an undesirable precedent, whereby the utility is effectively guaranteed that it can earn (or exceed) its

[1405] See D.09-03-025, mimeo, p. 4.

> authorized rate of return, regardless of its operating efficiency or inefficiency, simply by curtailing current maintenance activities, in the assurance that they could be refinanced later through recovery of deferred maintenance expenses in a succeeding rate case. This would create a perverse incentive for the utility to defer needed maintenance in the future. Consequently, we will disallow recovery of the $34.6 million requested for deferred maintenance activities in 1983 and 1984. Our disallowance of this expense for test year ratemaking purposes dose not relieve Edison of its responsibility to maintain the operating efficiency of its utility plant in a timely manner. Indeed, we expect Edison to fulfill that responsibility more conscientiously in the future.

(*SoCal Edison* (1982) 10 CPUC 2d 155,186; D.82-12-055, 1982 Cal. PUC LEXIS 1209.)

6.2.1.3 MWC KJ - Regulatory/License Compliance ($47.902 million)

PG&E describes the activities under MWC KJ as FERC-mandated license condition expenses, maintaining recreation, fish and wildlife facilities, environmental monitoring and mitigation activities; state and federal fees; mandated dam safety programs, plus mandated dam and reservoir maintenance. PG&E seeks $47.902 million for MWC KJ Test Year 2014 expenses, a 69.06% increase or $19.567 million over 2011 adjusted recorded expenses of $28.335 million. These MWC KJ expenses are divided into five sub-groups namely, (1) Ongoing License Conditions; (2) Fees; (3) Dam and Facility Safety; (4) FERC Balancing Account; and (5) Other. A comparison of the 2011 recorded adjusted expenses for these sub-groups and the corresponding PG&E's forecast 2014 Test Year expenses is illustrative of the disconnect between PG&E's actual needs and the 2014 Test Year estimates for most MWC.

	Ongoing License Conditions	Fees	Dam and Facility Safety	FERC Balancing Account	Other
2011Recorded Adjusted	$15,877,000	$8,219,000	$3,281,000	$55,000 [1406]	$903,000
2014 Forecast Expense	$19,093,000	$12,264,000	$9,208,000	$6,286,000	$1,053

[1406] This is not a misprint. The intended sum is fifty-five thousand dollars.

PG&E does not provide any explanation for how it derived the substantial increases in the 2014 forecast expense which covers the same number of projects as did the 2011 recorded adjusted. In fact for FERC Balancing Account which increased by over 11,000 percent, PG&E's only explanation is that "[t]he increases in FERC license compliance costs are highly uncertain and depend on FERC issuing new licenses or license amendments for several major hydro projects."[1407] PG&E has the burden of prove in this proceeding and should not be allowed to skirt that burden by simply stating that because the costs are uncertain, it had to increase the historical cost data by 11,000 percent.

Further, while every data available establishes that PG&E has no need to spend additional funds on Dam facility safety, PG&E continues to use dam facility safety as a rationale in many of its Hydro MWCs (See Liberty Consultants, See EPAC testimony…)

DRA recommends that the Commission adopt $31.651 million for MWC KJ - Regulatory/ License Compliance. This recommendation is $3.316 million more than PG&E's 2011 recorded adjusted expense for the same category of expenses in 2011 and the equivalent of a three year average of the recorded adjusted expenses from 2010 to 2012. [Fn. DRA's ES Report p. 29.] In choosing a three year average, DRA noted:

> PG&E's recorded adjusted expenses for MWC KJ increased by $8.966 million between 2007-2010, from $22.277 million in 2007 to $31.243 million in 2010. PG&E's expenses declined by $2.908 million between 2010 and 2011, from $31.243 million in 2010 to $28.335 million in 2011. The highest recorded figure for the five year period (2007 - 2011) was in 2010 of $31.243 million. The five year average (2007 - 2011) is $26.849 million; the six-year average is [2007 - 2011] is $28.271 million, and the three year average (2010 - 2012) is $31.651 million.

(Ex. 79, DRA-11, pp. 29 – 30 (footnote).)

[1407] Ex. 24 (PG&E-6), p. 2-85.

"The largest increase in 2014 regulatory work is associated with the pending license implementation work emanating from new FERC licenses. These costs are shown in the 'FERC Balancing Account' category in the preceding Figure 2-23 and Table 2-13. The increases in FERC license compliance costs are highly uncertain and depend on FERC issuing new licenses or license amendments for several major hydro projects."

Thus in choosing a three-year average, DRA was very liberal and generous in its forecast of MWC KJ's Test Year 2014 expense, even including the anomalous 2012 expense which was over $5 million dollars more than the largest recorded adjusted expense of all the available historical data for the prior six years.

6.2.1.4 MWC KI – Maintain Hydro Structures, Roadways and Infrastructures [$14.625 Million]

DRA recommends $11.150 million for PG&E's MWC KI – Maintain Hydro Structures, Roadways and Infrastructures, using PG&E's 2011 recorded adjusted expense of the same amount. This recommendation is consistent with the fact that "[t]here is no question as to the effectiveness of dam safety management in Power Generation [and] [t]he processes in place are extensive, and have grown more rigorous and testing with time."[1408]

The type of work required to maintain hydro structures, roadways and infrastructure as such routine activities as "assessment and inspection of roads, bridges and other infrastructure, plus routine annual recurring repairs."[1409] PG&E does not dispute that FERC and DSOD conduct an "assessment and inspection of roads, bridges and other infrastructure", and as Liberty Consultant noted, PG&E also uses an extensive array of consultants to perform these duties. There clearly overlap in the amount of assessment and inspection that goes on in Hydro given that it has the highest exposure to the general public for recreational facilities and poses a greater consequence in the event of failure. Thus, as Liberty noted there is no shortage of attention on maintaining these facilities. In 2011, PG&E management imputed $13.853 million to MWC KI from the last GRC's approved settlement, but PG&E was still unable to spend all the sum imputed as planned, spending only $11,150 million.

In order to justify a 31% increase in MWC KI costs over 2011 adjusted recorded expenses, PG&E argues that the "increase is due to performing 20 non-routine painting, paving and roof repair projects."[1410] DRA believes there are non-routine projects in every GRC's MWC KI expense, but PG&E should not be allowed to escalate "painting, paving and roof repair

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[1408] Liberty Report, p. 66.

[1409] Ex. 24 (PG&E-6), p. 2-88.

[1410] Id., p. 2-90, lines 2 – 4.

projects" that are usually embedded in annual historical costs of MWC KI for future GRCs in this Test Year request. Further describing why the incremental fund is needed, PG&E stated:

> Thus funding is needed to improve the material condition of the hydro facilities by stopping facility degradation, extending the life of the facilities, and to avoiding increases in future infrastructure maintenance and replacements.

(Ex. 24, PG&E-6, p.2-90, lines 4-7.)

In stating that the incremental funding in MWC KI is needed to "[avoid] increases in future infrastructure maintenance and replacements" PG&E unwittingly admits that it has accelerated non-routine specific projects that would have ordinarily been in future GRCs as the justification for a 30% increase in Test Year 2014 forecast for MWC KI. However, because PG&E has not provided any documentation showing which particular facilities, roadways or roofs will be maintained by the requested funds, there is no way to prevent PG&E from embedding the same request in future GRC's with an averaging of historical data.

PG&E concedes that MWC KI is a "low priority work" and that the maintenance in MWC KI constitutes the same "core work that has been traditionally done in Hydro. No new type of work is forecast in this MWC."[1411] Therefore, the Commission should adopt DRA's recommendation of $11.150 million which is the same amount as the 2011 recorded adjusted expense and at least 10% or $1 million more than the MWC KI expense from any of the prior six years.

6.2.1.5 MWC KG – Operate Hydro Generation [$51.507 Million]

PG&E states that funding to operate the hydro systems generation is intended to support "skilled workforce in the hydro areas, plus the tools, computers, and materials needed to perform the real-time operation of valves, equipment and facilities; call maintenance when needed and respond to operating abnormalities."[1412] The forecast estimate for these activities in the Test Year 2014 is $51.507 Million, an increase of $12.267 million or 31.26% over 2011 recorded adjusted expenses of $39.240 million[1413]. DRA recommends $43.066 million as the forecast for

[1411] Id., p. 2-90.

[1412] Id., p.2-62, lines 9 – 13.

[1413] Ex. 79, DRA-11, p. 35, lines 12- 14.

MWC KG. DRA's estimate is very modest considering that PG&E has not provided any justification for why a work category that predominantly consists of base activities – i.e. year-in-year out and day-to-day activities is increasing by 31.26% over the cost of the same work done in 2011.

PG&E ratcheted up spending in 2011 over prior years historical expense for this category of costs[1414] by $5.204 million or 15.29% percent over 2010 recorded adjusted expenses of $34.036 million. DRA's recommendation further increases this anomaly of historical costs by $3.826 million. A review of MWC KG historical costs given that they are mostly base activities shows that DRA's recommendation is reasonable.

> PG&E's recorded adjusted expenses for MWC KG were relatively stable between 2007 and 2009 and averaged $31.557 million for the three year period. In 2010, PG&E's expenses increased by $2.228 million or 7% over 2009 recorded adjusted expenses of 31.808 million. … The average for the five year period (2007 – 2011) is $33.589 million and the three year average (2009 – 2011) is $35.028 million.

(Ex. 79, DRA-11, p.36, lines 8-14.)

DRA's recommendation for MWC KG is about $9.5 million more than the five year average of $33.589 million and $8 million more than the three year average for this category. PG&E's claim that DRA has only averaged historical costs without analyses of the basis or rationale provided for PG&E's forecast is unfounded. In fact although DRA wrote its report before the Liberty Consultants issued its report and did not have the opportunity to communicate with Liberty Consultants, both DRA and Liberty Consultants reached the same conclusions that PG&E could not substantiate the estimates for each proposed project or provide adequate rationale to support the incremental expenses[1415].

PG&E also included a forecast of $2.450 million ($7.350 million over three years) for a record management initiative called Documentum as part of its incremental funding request. However, this request appears to be the same request that PG&E proposed in the Pipeline Safety Enhancement Plan (PSEP) and the Commission rejected.[1416] Moreover, the activities included in

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[1414] Liberty Consultants Report, p. 66.

[1415] Ex. 79 (DRA-110), p. 35–36; Ex. 168, Liberty: Study of Risk Assessment and PG&E's GRC, p. 78.

[1416] D.12-12-030, p. 87.

MWC KG for record management initiative, which aim "to reduce operational risk with regards to the handling, identification, retrieval and management of records and information"[1417], are not new "and should be part of the routine and on-going maintenance activities that are already funded by ratepayers."[1418]

DRA's recommended funding level of $43.066 million is sufficient to serve PG&E's purposes including a reasonable improvement on its record management activities. Further, the increase in base operation expense that PG&E included in MWC KG "assumes the capital and expense forecasted for powerhouse automation, equipment upgrades, improvements in operation's tools and IT projects is implemented as planned"[1419], which is unlikely.

6.2.1.6 MWC JV – Maintain IT Applications and Infrastructure

PG&E's forecast for maintaining its IT applications and infrastructure is 347.26% more that its 2011 record adjusted expense. PG&E forecasts $3.350 million while the recorded adjusted expense for 2011 was $0.749 million. DRA recommends the Commission adopt $0.883 million as the forecast for MWC JV.

DRA's forecast was derived by normalizing PG&E's forecast after making adjustments to remove two IT projects. The two projects DRA removed were for RIM-Documentum and for Asset Management/Condition Based Maintenance, both of which PG&E claims it needs to address Hydro Operations Recordkeeping and document management deficiencies. This record keeping and management activities are part of the regulatory duties and obligation of the utility as such they costs to implement are already embedded in funding that PG&E has received in other work categories. It is important to note that PG&E's Hydro is regulated by FERC and DSOD and has manages hundreds of projects in a manner that has been found in compliance with all its regulatory obligations. If PG&E has been able to achieve this level of efficiency and compliance without the programs it now seeks to implement, the PG&E must have another program in place that is just as effective as the proposed new programs. Therefore, the Commission should not authorize PG&E a 347% increase in funding for MWC JV, but adopt

[1417] Ex. 26 (PG&E-6), p. WP 02 V.1, p.2-162.

[1418] Ex. 79 (DRA-79), p. 38, lines 8 – 9.

[1419] Ex. 24 (PG&E-6P, p. 2-68, lines 7 – 10.

DRA's recommendation for $0.883 million, which is still more than PG&E's 2011 adjusted recorded expense.

6.2.2 Capital Expenditures

PG&E's total capital expenditure request for TY 2014 is $636.5 million, for 2012 and 2013, PG&E requests $581.7 million and $516.5 million respectively[1420]. In 2011, PG&E recorded capital expenditure costs was $529.014 million, almost $100 million less than TY 2014 forecast[1421].

According to PG&E:

> The increase in capital expenditure in 2014 over the 2011 … is almost entirely driven by forecasted investments in PG&E's hydro system. The increases are primarily driven by (1) expenditures related to waterway projects that are needed to ensure public and employee safety, continued reliable operation of the associated downstream powerhouses, protection of downstream property, the enhancement of fishery habitats, and /or conveying consumptive water to agricultural and residential customers in the vicinity; and (2) reliability projects and programs such as generator rewinds, turbine and governor overhauls and/or replacements, transformer replacement, and large valve refurbishment, throughout the hydro system.[1422]

DRA reviewed ES capital expenditures and all associated documentation including the application, workpapers and related discovery for a better explanation of the escalation in capital costs.

> The significant increase in the Hydro area budgets warranted further review of the individual projects requested. This review reveals that several Hydro projects have the characteristic that a majority of their project spending is forecast to occur after the Test Year. This fact, coupled with steady increase in the Hydro budgets, make these projects good candidates to be rescheduled out of TY 2014. The details of these projects and DRA's proposed Hydro budget adjustments are discussed in the Hydro section.[1423]

[1420] Ex. 80 (DRA-12), p. 4.

[1421] Ex. 24 (PG&E-6), p. 1-29.

[1422] Ex. 24 (PG&E-6), p. 1-31.

[1423] Ex.80 (DRA-12), p. 4.

Therefore, DRA chose not to take exception with PG&E's justifications for the projects that form the basis of the capital expenditure forecasts. Instead, DRA addresses the forecast methodology that informed PG&E's TY 2014 requests.

PG&E's capital expenditures for ES from 2012 through 2014 funds plant investments in PG&E's hydroelectric, fossil fuel and alternative generation resources. Plant consists of generation equipment such as turbine, pumps, boilers, tools and other instrumentations and controls. ES also includes Information Technology (IT) costs and infrastructure investments in buildings, roads, bridges, and penstocks, most of which are appurtenant structures to dams[1424].

PG&E states that it operates the largest privately owned hydroelectric system in the United States[1425]. The hydroelectric generation assets in this system consist of 109 generating units at 68 powerhouses with a combined maximum generating capacity of 3,896 MW[1426]. PG&E claims that the primary drivers for the forecast capital expenditures are relicensing costs and the requirement to implement new licensing conditions, dam safety modifications in response to regulatory guidelines and reliability projects to keep plants running[1427].

PG&E's fossil fuel generation consists of two new state of the art facilities, the Gateway Generation Station (GGS) and Colusa Generating Station (CGS) as well as the Humboldt Generating Station (HBGS). GGS was put in service in January 2009, and CGS was put in service in December 2010 and HBGS was put in service in September 2010[1428].

PG&E's other generating assets include a fleet of photovoltaic (PV) and fuel cell facilities, the latter of which are located in San Francisco State University and California State University East Bay.

6.2.2.1 PG&E's Justifications For ES Capital Projects

PG&E developed and forecasted its capital expenditures on a project-by-project basis under 17 major work categories (MWC) and, in all, there were 744 projects that formed the basis for PG&E's capital expenditure requests in this 2014 TY GRC. Rather than take issue with

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[1424] Ex. 80 (DRA-1), p. 1.

[1425] Ex. 24 (PG&E-6), p. 1-6.

[1426] Id.

[1427] Ex. 24 (PG&E-6), p. 1-7.

[1428] Ex. 24 (PG&E-6), p. 1-9.

every single justification for each of the 744 projects, especially given that PG&E has not provided a cost-benefit analysis with these justifications or quantified the risk assessment the projects are intended to address or even prioritized the projects in a clear order, DRA focused on the reasonableness of doing all these projects in one rate cycle and the likely costs and consequences of deferring some of these projects to subsequent rate cycles.

It is interesting to note that Liberty Consultants took the same approach after examining PG&E's application and workpapers and the process by which PG&E developed its Hyrdo projects for this GRC.

Liberty Consultants stated:

> In addition to creating the major risk in Power Generation, hydro risk is also the forerunner for implementation plans. This process has been far from straightforward. …
>
> The lack of final, complete, approved RRP for the hydro risk is therefore not surprising. This evolution, however, illustrates the need for a better approach. Hydro risk capital projects proposed so far in the 2014-16 window already exceed $100 million. One should question what PG&E's management requirements are for a project of this magnitude. We suggest that the levels of commitment here require at a minimum a well-thought-out project design, a rigorous scoping and approving process, a detailed budget and schedule, and a project management scheme to track the execution of the project from cradle to grave. To the extent such structure is not possible for whatever reason, the work can be divided into smaller packages, in order to assure the meeting of management objectives.
>
> … [M]anagement and others charged with governance and oversight need a picture of the work that makes sense. In this regard, the inability to present a coherent story on the scope of the implementation work for the hydro risk, its eventual cost, its schedule, and what the hydro system looks like when it is done (i.e., how the risk profile has changed), is a shortcoming at this point.

(*Study of Risk Assessment and PG&E's GRC*, Report to the Safety and Enforcement Division by Liberty Consultants.)

Regarding the linkage between risk and safety-related spending as justification for the projects for PG&E's ES capital expenditure, Liberty Consultants wrote:

> Any linkage between risk and safety related spending strikes us as irrelevant if one cannot understand the resulting rationale for the level of spending. An infinite number of projects can be conceived; most

> organizations do indeed generate a lengthy wish list. Management therefore needs the ability to "draw the line" at some appropriate level; *i.e.* , to determine what aggregate level of spending makes the most sense, and to decide which proposals to delete or defer.
>
> …Liberty was unable to determine how that process was conducted or, more importantly, what the rationale for the final choices was once the process was completed. The closest we were able to obtain a rationale was the following, in response to the direct question of how the cutoff levels were established in the GRC:
>
> *The targets were proposed based on an assessment of the risks of rescheduling work to future years vs. the ability of Power Generation and its contractors to successfully execute the work. The forecasts presented in the GRC represent a ramp-up of expenditure over the 2014-2016 period. This is a level of investment that PG&E believes is necessary to continue to provide safe, reliable and affordable energy while meeting all federal, state, and local regulatory requirements, and public safety, recreation and environmental commitments.*
>
> Such an explanation does not present a convincing rationale and justification for a spending level substantially beyond previous levels. It raises the question of how the regulator and other stakeholders can judge the appropriateness of the chosen spending plan. It begs the same question for management. [Emphasis in original][1429]

6.2.2.2 Discussion / Analysis of Hydro Operations MWCs

PG&E's requests $262.5 million for 2012, $261 million for 2013 and $344.7 million (nominal dollars) for TY 2014 Hydro Operations capital expenditures. DRA recommends $293.0 million for 2012, $260.4 million for 2013, and $265.9 million for TY 2914. These adjustments reflect significant reductions in TY 2014 Hydro Operations capital expenditures, "a modest increase in 2012 (as DRA accepts 2012 recorded capital expenditures which were higher than PG&E's 2012 forecast), and a minor adjustment to 2013 based on DRA's IT recommendation"[1430].

[1429] Id., pp. 78-79.

[1430] Ex. 80 (DRA-12), p. 5.

The Hydro issues are addressed by MWC. Table 12-3 of DRA's Report[1431] summarizes PG&E's 2012-2014 requests for Hydro Operations capital expenditures and DRA's corresponding recommendation by MWCs for Hydro Operations:

Table 12-3[1432]
Energy Supply Capital Expenditures for 2012-2014
Hydro Operations
(In Thousands of Dollars) [1433]

Description	DRA Recommended			PG&E Proposed[1434]		
	2012	2013	2014	2012	2013	2014
MWC 2F	$7,759	$3,212	$12,083	$3,235	$3,735	$14,050
MWC 05	$421	$880	$2,906	$231	$880	$2,906
MWC 11	$34,237	$39,566	$40,233	$26,408	$39,566	$45,176
MWC 2N	$51,005	$36,116	$53,670	$30,668	$36,116	$86,244
MWC 2M	$83,168	$109,278	$105,437	$82,391	$109,278	$121,702
MWC 2L	$100,286	$59,953	$35,614	$108,246	$59,953	$49,614
MWC 12	$11,385	$5,958	$5,320	$7,535	$5,958	$8,320
MWC 2P	$4,786	$5,477	$10,652	$3,761	$5,477	$16,652
Total	$293,047	$260,440	$265,915	$262,475	$260,963	$344,664

6.2.2.3 MWC 2M - Install/Replace Hydro Electric Generating Equipment

The installation and replacement of Hydro Electric Generating Equipment is the largest cost category in PG&E's Hydro forecast for TY 2014. This activity is listed in MWC 2M. Recorded spending in 2011 was driven by turbine systems upgrades, and PG&E claims that forecast spending for 2014 is dominated by the generator systems category[1435], such as the

[1431] Ex. 80 (DRA-12).

[1432] Ex. 80 (DRA-12), p. 5.

[1433] Since DRA does not take issue with PG&E's justifications for the projects at this time, it is not necessary for this brief to provide lengthy descriptions of each MWC project and the project's purported purpose in this analysis. The same can be obtained from PG&E's papers: (1) Ex. 24, (PG&E-6 (Prepared Testimony); (2) Ex. 25C, PG&E-6 WP 02 and 04 Confidential; (3) Ex. 26, PG&E-6 WP 02 V1; (4) Ex. 27, PG&E-6 WP 02 V2; (5) Ex. 28, PG&E-6 WP 03; (6) Ex. 29, PG&E-6 WP 04-06; (7) Ex. 30, PG&E-7; (8) Ex. 58, PG&E-21 (ES Rebuttal)

[1434] Ex. 24 (PG&E-6), p. 2-161, Table 2-23.

[1435] Ex. 24 (PG&E-6), pp. 2-104, 2-107.

generator replacement work during forecast for 2013-2015 at the 1,212 MW Helms Pumped Storage Project.

PG&E's forecast for MWC 2M in 2012 was $82.4 million and for 2013 is $108.3 million, a 30 percent increase over 2012. For 2014, PG&E forecast $121.7 million, another significant increase over 2013 forecast and about 50 percent over 2012. DRA recommends a TY forecast of $105.4 million. These adjustments are based on a project-by-project review of MWC 2M for the 2011-2016 time period as follows:

> PG&E's hydroelectric capital project data base for 2011-2016 includes 424 projects in eight major work categories (MWC's).[1436] Recorded data is entered for 2011, and forecast data is used for 2012-2016. Most of the projects have significant activities forecast for 2012-2014 such that each individual project will be at or near completion in 2014. However, six projects in MWC 2M have a different spending pattern. These six projects have TY 2014 spending of at least $1 million, had planned spending prior to 2014 of less than $1 million, and have at least 50 percent of the total project spending in 2015-2016. The following table demonstrates this spending pattern. The far right column shows the ratio of 2014 spending to the total project spending. All of the ratios are well below 0.50. Table 12-4 shows these projects:

Table 12-5[1437]
DRA Adjustments to Hydro MWC 2M
(In Thousands of Dollars)

order	Hydro Project Description - DRA Adjustments	MWC		PG&E 2012	PG&E 2013	TY 2014	AY 2015	AY 2016	total proj.	rat.
5745706	Pit 4 Unit 2 Turbine Upgrade	2M		$60	$500	$5,000	$10,000	$0	$15,560	0.32
5720586	AM: Needle Valve CAP	2M		$0	$0	$1,000	$3,000	$5,000	$9,000	0.11
5720588	AM: Turbine / Runner Replacement CAP	2M		$0	$0	$3,000	$5,000	$7,500	$15,500	0.19
5720626	AM: Cooling Water Pr	2M		$0	$0	$1,000	$3,000	$3,000	$7,000	0.14
5720585	AM: Governor Program CAP	2M		$0	$0	$3,000	$5,000	$7,500	$15,500	0.19
576000315	57Exh6 Ch2 MWC2M FuncEHP Asset UCC120 Op	2M		$0	$0	$2,365	$4,786	$200	$7,351	0.32
			total:	$60	$500	$15,365	$30,786	$23,200	$69,911	0.22

The total capital cost that will be born in this rate cycle for the six projects that DRA proposes to remove from this TY 2014 rate case is $15.4 million as shown in the foregoing table[1438]. PG&E's testimony supports this recommendation.

[1436] Ex. 24 (PG&E-6), pp. WP 2-25 – WP-2-39.

[1437] Ex. 80 (DRA-12), p. 8.

> Commission adoption of Hydro's forecast for these major equipment replacements will allow PG&E to implement these important reliability projects as forecasted. If not adopted, the ongoing projects would likely be completed as planned, but the projects not yet started, would be rescheduled one or more years into the future.[1439]

6.2.2.4 MWC 2N – Install/Replace Reservoirs, Dams, & Waterways

Reservoirs, Dams, & Waterways projects constitute the second largest capital cost category in the Hydro and are forecast in MWC 2N. PG&E states that the most capital spent on these projects in 2011 focused on emergency canal work, but while major canal work is forecasted to continue in 2014, work on penstock systems, flumes and dams would significantly increase planned spending.

PG&E forecasts $86.2 million for TY 2014 MWC 2N, which is about 120 percent above the Company's 2013 forecast. The main driver for this increase in 2014 is planned spending on penstock systems, which is budgeted at $25 million, 25 times greater than 2011 actual spending.

DRA recommends a TY 2014 forecast of $53.7 million based on a project-by-project review of MWC 2N that takes into consideration the 2011-2016 schedule for forecast spending.

> Similar to the spending pattern analysis conducted for MWC 2M, MWC 2N has a limited number of projects where the expenditure forecast is weighted towards the latter two years of the rate case cycle. Six projects meet the criteria used above with one exception. The Drum Canal project has pre-2014 spending above $1 million. However, since the 2014 cost to total cost spending ratio is 0.30, and the TY 2014 costs are significant, this project remains a good candidate to be rescheduled out of the Test Year. Based on the $32.5 million adjustment total from the table above, DRA recommends a $53.7 million budget for TY 2014 in MWC 2N.[1440]

Table 12-7 in DRA's Report, reproduced below, illustrates the analysis that supports DRA's recommendation.

[1438] This excludes the costs that DRA presumes have already been incurred in 2012 and 2013 for about $560,000.

[1439] Ex. 24 (PG&E-6), pp. 2-109 to 2-110

[1440] Ex. 80 (DRA-12), p. 9.

Table 12-7[1441]
DRA Adjustments to Hydro MWC 2N
(In Thousands of Dollars)

order	Hydro Project Description - DRA Adjustments	MWC		PG&E 2012	PG&E 2013	TY 2014	AY 2015	AY 2016	total proj.	rat.
5720595	AM: Penstock Program CAP	2N		$0	$50	$8,000	$18,000	$38,000	$64,050	0.12
5704239	Drum Canal/Gunite Work (Cap)	2N		$2,000	$1,800	$13,500	$13,500	$13,500	$44,300	0.30
5743220	Centerville New Penstock inlet structure	2N		$0	$504	$3,004	$17,005	$0	$20,513	0.15
5720633	AM: Dam Remediation	2N		$0	$0	$5,000	$15,000	$40,000	$60,000	0.08
5720584	AM: Waterconveyance Wood Flume Replace	2N		$0	$500	$2,000	$15,000	$10,000	$27,500	0.07
576000351	57Exh6 Ch2 MWC2N FuncEHP Asset UCC120 Opl	2N		$0	$0	$1,020	$1,405	$300	$2,725	0.37
			total	$2,000	$2,854	$32,524	$79,910	$101,800	$219,088	0.15

6.2.2.5 MWC 2L – Install/Replace Hydro Electric Generating Safety & Regulatory Requirements

PG&E states that there are five types of work in MWC 2L: (1) Dam Safety; (2) Public and Waterway Safety; (3) Employee Safety; (4) NERC (North America Electric Reliability Council) Security and Records Management; and (5) Regulatory and Other. Recorded costs for MWC 2L ran up precipitously in 2011-2012 due to the Crane Valley Dam project, but declined in 2013 due to the completion of the project.

> PG&E's 2014 MWC 2L forecast includes three projects with the forecast spending pattern similar to the previous categories where the largest percentage of the budgets are after TY 2014. The largest of these projects, the Dam Safety Instrumentation Automation Program is forecast to invest $10 million of its $42.5 million total costs in 2014.[1442]

DRA has identified the Dam Safety Instrumentation Automation Program, the Arc Flash Remediation and the System Protection & Controls projects as projects that should be rescheduled out of 2014. Therefore, DRA recommends a total budget of $35.6 million, or a $14 million decrease from PG&E's request, for 2014 MWC 2L capital expenses, as a result of the rescheduling adjustment.

6.2.2.6 MWC 11 – Relicensing Hydroelectric Generation

MWC 11 consists of activities that PG&E maintains are necessary for relicensing its Hydro generation facilities. PG&E's capital expenditures for TY 2014 are forecast for projects

[1441] Ex. 80 (DRA-12), p. 9.

[1442] Ex. 80 (DRA-12), p. 10.

in the following four subcategories: (1) FERC Balancing Account Licensing; (2) FERC Balancing Account License Conditions; (3) Ongoing License Conditions, and (4) Other.

PG&E's 2012 recorded expenditures of $34.2 million already has exceeded same year forecast of $26.4 million. MWC 11 forecasts for 2013 and 2014 are $39.6 million and $45.2 million respectively[1443]. DRA accepts MWC 11 recorded capital expenditures of $34.2 million and 2013 forecast of $39.6 million but finds there are three projects in PG&E's TY 2014 for MWC 11 with 90 percent of the budget for their implementation projected for 2015-2016. Removing these projects from the TY 2014 rate cycle would reduce the TY 2014 forecast by $4.9 million. Therefore, DRA recommends that these projects be removed from this rate cycle and that PG&E forecast of $45.2 million be reduced accordingly by $4.9 million for a TY 2014 DRA recommendation of $40.5 million.

Although, PG&E argues that one of the projects DRA proposes to remove, Kilarc-Cow License Decommissioning, is ongoing and has sunk costs, the record evidence shows that these costs were scheduled to commence in 2013, and thus, could not have incurred such sunk costs at the time PG&E rate application was filed.

6.2.2.7 MWC 12 – Implement Environmental Projects

PG&E primarily forecasts oil spill prevention projects, such as replacement of hydro powerhouse bearings and sumps under MWC 12.[1444] Although not a major budget category in the Hydro area, MWC 12 recorded costs have steadily increased since 2007.

While DRA accepts PG&E's 2012 recorded costs and 2013 forecast costs for MWC 12, a review of the capital project data base shows one problematic project in MWC 12, the Kerckhoff 1 Powerhouse project, with the forecast spending pattern where the costs are significantly less in TY 2014 rate cycle. PG&E states that the Kerckhoff 1 Powerhouse project is one of eight projects to begin in 2014.[1445] However, this is the only one of the eight projects with a TY-to-total-project-spending ratio below 0.50. DRA recommends that this project be rescheduled to subsequent TY rate cycles, thus removing the TY 2014 capital cost of $1.3 million for the project from MWC 12.

[1443] Ex. 80 (DRA-12), p. 12.

[1444] Ex. 24 (PG&E-6), p. 2-139.

[1445] Ex. 24 (PG&E-6), p. 2-139.

PG&E's forecast for MWC 12 in TY 2014 is $8.3 million, DRA's recommendation for TY 2014 based on rescheduling Kerckhoff 1 Powerhouse project is $7million.

6.2.2.8 MWC 2P – Install/Replace Hydro Electric Generation Buildings, Grounds, and Infrastructure

PG&E records the capital expenditures for the installation and replacement of buildings, grounds, and the infrastructure associated with hydro generation system in MWC 2P. This infrastructure in this category includes roads, bridges, roofs, and various outdoor structures. While this projects are not emergency projects, their recorded costs have steadily increased in recent years[1446].

PG&E's recorded spending for MWC 2P was $4.8, $1 million above PG&E's 2012 forecast in this GRC. PG&E's TY 2014 forecast for MWC 2P is $16.652 million, which is 400 percent above the 2012 recorded spending. DRA recommends that the Commission adjust PG&E's TY 2014 forecast by $6 million based on project spending pattern for Rock Creek Yard Hydro Service Center project which is weighted heavily towards the 2015-2016 time frame.

> MWC 2P is a category where the low TY to total project ratio is low (.21).The Auburn hydro service center project has forecast spending of $6 million, $10 million, and $12 million in 2014, 2015, and 2016, respectively. The 31 other MWC 2P projects can still be funded based on PG&E's forecast. DRA recommends a $10.7 million budget for the TY 2014 MWC 2P forecast, a $6 million adjustment to PG&E's forecast.[1447]

6.2.2.9 MWC 05 – Tools and Equipment

PG&E records costs for purchasing capital tools and equipment used in the Hydro area under MWC 05. Recorded costs for these tools and equipment have remained under $1 million from 2007 through 2012. In fact, in 2012 said costs were $421, 000. However, PG&E TY 2014 forecast for MWC 05 was $3 million. PG&E claims that the TY 2014 forecast is due to new dredging equipment to be incurred in 2014 at an estimated to cost of $1.8 million. While this increase reflects the suspicious case of all costs rising in 2014 and beyond, DRA does not take issue with PG&E requests for MWC 05.

[1446] See Table 12-13, Ex. 80 (DRA-12), p. 14.

[1447] Ex. 80 (DRA-12, p.16).

6.2.2.10 MWC 2F – Building Information Technology Applications & Infrastructure

DRA's recommendations for MWC 2F are primarily based on DRA's testimony on the Shared Services and IT wherein DRA recommended that forecasts developed using PG&E's Concept Estimating Tool should be adjusted downward by 14 percent to reflect the actual performance of the Concept Estimating Tool as reflected in the 2011 recorded costs of such forecasts.

MWC 2F records capital costs for IT projects planned throughout the Company. Prior to 2011, MWC 2F had little or no recorded capital costs for Hydro operations. However, in 2012 PG&E recorded $7.8 million in capital costs, despite a $3.2 million forecast, and for 2013 and TY 2014, PG&E forecasts $3.7 million and $14.1 million respectively.

Consistent with DRA's IT recommendation for forecasts developed using the Concept Estimating Tool, DRA recommends that the 2013 and TY 2014 forecasts be reduced to $3.2 and $12.1 million respectively.

6.2.3 Balancing Account

PG&E proposes to establish two-way balancing accounts for FERC Hydro licensing and licensing implementation work under MWC 11 because of challenges with determining the nature and timing of the costs of implementing new license conditions and receiving new licenses from FERC.

PG&E describes the FERC licensing work under MWC 11 as follows:

> MWC 11includes the investments needed to obtain new long-term (30 to 50 years) FERC licenses for the existing hydro facilities upon expiration of the previous licenses; to amend the FERC licenses to reflect major changes in the license projects facilities and /or operations; and to install or construct new capital equipment or facilities to comply with the FERC existing or new license conditions.[1448]

DRA opposes PG&E's proposal for these balancing accounts for the following reasons:

> PG&E proposes that $28.6 million of the MWC 11 capital budget of $45.2 million receive two-balancing account treatment for ratemaking purposes. PG&E also proposes that Hydro Relicensing expenses be subject to two-way balancing account treatment; this is addressed in Exhibit DRA-11

[1448] Ex. 24 (PG&E-6), p. 2-131.

> (Energy Supply Expenses). PG&E bases its proposal on the fact the hydro relicensing activities are subject to greater uncertainty due to federal regulatory schedules, lengthy stakeholder processes and incongruity with the three-year general rate case cycle.
>
> For the purposes of capital budgeting, a two-way balancing account does not appear to provide any real benefits to ratepayers. First, the historical recorded costs have not been treated with the balancing account, so there is no way to capture any over-collection ratepayers could have due in this general rate case cycle. Second, any differences between actual and adopted costs for ratemaking purposes will be trued up in the generation balancing account. Finally, two-way balancing treatment tends to favor inflated forecasting when it is known that unspent funds will be returned to ratepayers. It would not be a good policy for ratepayers to provide this "safety cushion" for the utility's capital budget. For all of these reasons, DRA recommends that the two-way balancing account proposal not be adopted for the hydro relicensing capital items.[1449]

PG&E is asking for a two-way balancing account at a time when it needs it the least. Between 2001 and 2009 PG&E received ten new hydro licenses, which conditions it has been implementing through forecasts from prior GRCs. In this Test Year GRC PG&E is asking for a balancing account for only four projects it expects will be issued FERC licenses in 2012. Further, if the uncertainty PG&E claims about forecasting renewal and amendment forecasting durations is true, then for licenses that PG&E applied for from 2002 through 2007, PG&E would have already forecast their renewal and embedded the cost of implementing them in prior GRCs so as not to be caught unfunded should they be renewed quicker than anticipated. The four licenses PG&E expects to be issued in 2012 are (1) Upper North Fork Feather River – Application filed in 2002, (2) Poe - Application filed in 2003, (3) Chili Bar - Application filed in 2005, and (1) DeSabla Centerville - Application filed in 2007.

PG&E admits it has dealt with "difficult to forecast FERC licensing renewal and amendment process durations, and costs to implement the resulting new license conditions." The record shows far too many such FERC license renewals in the past for PG&E to claim a new ratemaking mechanism on the basis of uncertainty. PG&E also has embedded costs that can be reallocated and utilized in Test Year 2013 if incremental funding over DRA's recommendation is needed.

[1449] Ex. 80 (DRA-12), pp. 12-13.

6.2.4 Balancing Account

PG&E proposes a new two-way balancing account for pending FERC licenses to be issued in 2012 and 2014, the implementation of which PG&E claims are difficult to estimate. DRA opposes PG&E's request for a two way balancing account because it would likely result in recovery of funds that are currently embedded in historical costs from prior GRC estimates.

PG&E is asking for a two-way balancing account at a time when it needs it the least. Between 2001 and 2009 PG&E received ten new hydro licenses, which conditions it has been implementing through forecasts from prior GRCs. In this Test Year GRC PG&E is asking for a balancing account for only four projects it expects will be issued FERC licenses in 2012. Further, if the uncertainty PG&E claims about forecasting renewal and amendment forecasting durations is true, then for licenses that PG&E applied for from 2002 through 2007, PG&E would have already forecast their renewal and embedded the cost of implementing them in prior GRCs so as not to be caught unfunded should they be renewed quicker than anticipated. The four licenses PG&E expects to be issued in 2012 are (1) Upper North Fork Feather River – Application filed in 2002, (2) Poe - Application filed in 2003, (3) Chili Bar - Application filed in 2005, and (1) DeSabla Centerville - Application filed in 2007.

PG&E admits it has dealt with "difficult to forecast FERC licensing renewal and amendment process durations, and costs to implement the resulting new license conditions." The record shows far too many such FERC license renewals in the past for PG&E to claim a new ratemaking mechanism on the basis of uncertainty. PG&E also has embedded costs that can be reallocated and utilized in Test Year 2013 if incremental funding over DRA's recommendation is needed.

6.3 Nuclear Operations Costs

PG&E's Nuclear Operations Program maintains and operates PG&E's nuclear generating assets located at the Diablo Canyon Power Plant (DCPP). These assets consist of two nuclear pressurized water reactor (PWR) units and steam-electric turbine generators, feed water systems and cooling water systems, and related facilities.

6.3.1 Expense

PG&E forecasts $415.500 million for Nuclear Operations expenses for Test Year 2014. This is an increase of $101.293 million, or 32.24%, over 2011 recorded adjusted expenses of

$314.207 million.[1450] DRA recommends a forecast for PG&E's Nuclear Operations expenses of $322.783 million.[1451]

For the most part, PG&E developed its forecasts based on 2011 recorded costs, one-time adjustments to those costs and PG&E's estimated additional costs for proposed projects.[1452] PG&E's request also includes continued funding for an "aging workforce program"[1453] and a proposal to establish a two-way balancing account for "new nuclear safety and security regulatory-mandated projects".[1454]

PG&E records expenses for its Nuclear Operations in nine Major Work Categories (MWCs) for the Test Year: AB – Support, with a forecast of ($37,400) million, AK – Manage Environmental Operations, with a forecast of $3.068 million, BP – Manage DCPP Business, with a forecast of $15.287 million, BQ – DCPP Support Services, with a forecast of $46.353 million, BR – Operate DCPP Plant, with a forecast of $107.340 million, BS – Maintain DCPP Plant Assets, with a forecast of $184.178 million, BT – Enhance DCPP Personnel Performance, with a forecast of $23.536 million, BV – Maintain DCPP Plant Configuration, with a forecast of $70.238 million, and JV – Maintain IT Applications, with a forecast of $2.900 million.[1455]

PG&E's 2014 forecast of $415.500 million includes projects that were initially proposed during its 2011 GRC, but were deferred or rescheduled.[1456] PG&E identified some of those deferred projects. However, DRA has concerns that there are other deferred maintenance projects that were not identified by PG&E for which it received funding in past GRCs, and is requesting funding again in this one. During a March, 2013, tour of PG&E's DCPP facility, DRA was told that some of PG&E's 2014 proposed projects are for on-going projects (i.e., Cybersecurity, Emergency Preparedness, Procedure Upgrade, etc.). These projects have

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[1450] Ex. 24 (PG&E-6), p. 3-3, Table 3-1. PG&E's 2011 GRC Imputed amount of $328.8 million is $14.593 million more than its 2011 recorded adjusted expenses of $314.207 million. (PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018) (Ex. 79, p. 44, footnote 77.)

[1451] Ex. 105 (DRA Errata), p. 44.

[1452] Ex. 24 (PG&E-6), p. 3-83. The exception is PG&E's forecasts for Information Technology projects.

[1453] Ex. 24 (PG&E-6), p. 3-30.

[1454] Ex. 28 (PG&E-6 workpapers), p. WP 3-1.

[1455] Ex. 28 (PG&E-6 workpapers), p. WP 3-1.

[1456] Ex. 24 (PG&E-6), p. 3-25.

embedded historical costs. Others of PG&E's 2014 proposed projects may have already been completed, have been rescheduled, or may not be completed.

DRA reviewed each of PG&E's Major Work Categories individually. For the reasons discussed in more detail below, DRA disputes PG&E's forecasts for MWC AK – Manage Environmental Operations, with a forecast of $3.068 million, BP – Manage DCPP Business, with a forecast of $15.287 million, BQ – DCPP Support Services, with a forecast of $46.353 million, BR – Operate DCPP Plant, with a forecast of $107.340 million, BS – Maintain DCPP Plant Assets, with a forecast of $184.178 million, and BT – Enhance DCPP Personnel Performance, with a forecast of $23.536 million, BV – Maintain DCPP Plant Configuration, with a forecast of $70.238 million, and JV – Maintain IT Applications with a forecast of $2.900 million.[1457]

In its Rebuttal, PG&E says that:

> …DRA generally adopted historical recorded costs….. In using this look-back approach, DRA fails to apply an inflation adjustment, overlooks more recent spending trends in 2012 and 2013, and ignores altogether new projects and Nuclear Regulatory Commission (NRC) and business requirements that drive PG&E's 2014 forecast.[1458]

PG&E makes these arguments in various combinations in each of the nuclear expense Major Work Categories that DRA and PG&E dispute. DRA will address these at the outset.

For example, DRA is criticized in this Rebuttal exhibit for overlooking "….more recent spending trends in 2012 and 2013" where elsewhere, DRA is criticized for using more recent spending trends.[1459] In any event, DRA did, as discussed in more detail below, use 2012 data for its forecast. In Major Work Category BR, for instance, DRA recommends the Commission adopt a forecast of $91.921 million[1460] which is certainly more comparable to PG&E's actual 2012 recorded expenses of $92.503 million[1461] than PG&E's 2012 forecast. In Major Work Category BS, DRA's recommendation of $141.184 is actually higher than PG&E's 2012 recorded costs of $137.341 million.

[1457] Ex. 79 (DRA-11), p. 45.

[1458] Ex. 58, p. 3-1.

[1459] See, e.g., Ex. 63 (PG&E-24), p. 3-1.

[1460] Ex. 79, p. 43, Table 11-15.

[1461] Ex. 79, p. 11, Table 11-11.

PG&E also criticizes DRA for "ignoring altogether" new projects and NRC and business requirements that drive PG&E's forecast. By ignored, PG&E's witness says he meant, "…did not take into account."[1462] PG&E is wrong. DRA's testimony addresses the projects PG&E identified. As a general matter, however, where PG&E already has embedded funding for a project, or where PG&E's decision in the past to divert funds elsewhere has led to increased costs now, DRA opposes making ratepayers pay over and over for work they have already funded.

As to PG&E's criticism that DRA failed to apply an inflation adjustment to Nuclear Expenses, DRA neither escalated nor de-escalated the 2011 recorded numbers, as this is generally done in the Results of Operations (RO) Model.[1463]

PG&E also criticizes DRA for "ignoring" an accounting change PG&E made in 2011 to move Security costs it had previously recorded in several Major Work Categories to one Major Work Category. Far from ignoring the accounting change, DRA asked PG&E to provide a detailed breakdown of the projects causing the change in expense levels.[1464]

PG&E identified the accounting change beginning in 2011 as the reason for the decreases in MWCs BR, BS, and BV and the increase in MWC BQ. But PG&E never identified what those Security costs were that were recorded in MWCs BR, BS, and BV for the years prior to 2010. The change in accounting does not change the fact that PG&E has embedded ratepayer funding for Security costs from prior years. So, for example, DRA's forecast for MWC BR uses an average of the years 2010, 2011 and 2012. The year 2010 is the year before PG&E implemented its accounting change removing Security costs. The year 2011 is when PG&E began direct charging Security costs to MWC BQ. And 2012 is the last recorded year, that PG&E earlier criticizes DRA for "overlooking."[1465]

PG&E also claims that DRA failed to "consider work force additions necessary to allow for hiring ahead of attrition."[1466] In fact, DRA did consider PG&E's "aging workforce

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[1462] 25 RT 3091, Halpin/PG&E.

[1463] 26 RT 3365-3366, Godfrey/ DRA.

[1464] Ex. 100 (DRA workpapers), pp. 80-93.

[1465] Ex. 58 (PG&E-21), p. 3-1.

[1466] See, e.g., Ex. 58 (PG&E-21), p. 3-41.

argument" -- in this GRC and in previous GRCs where PG&E has repeatedly made the same argument.[1467]

PG&E requested and received funding in its TY 2007 and TY 2011 GRC to establish various training programs and to fund additional positions to offset attrition.[1468] PG&E's forecasts have been consistently overstated in regards to its aging workforce issue and it has received more than enough funding, still embedded in rates, to address it.

For example, in PG&E's 2011 GRC, DRA noted that PG&E's forecast of staff attrition for 2009 greatly exceeded the actual attrition in 2009. PG&E's 2011 GRC authorized amount of $328.8 million exceeded its 2011 recorded adjusted expenses of $314.207 million.[1469] DRA continues to recommend that The Commission adopt DRA's test year estimate for PG&E's Nuclear Operations which already includes embedded funding for PG&E's aging workforce program.[1470]

According to PG&E, "[i]f the DRA or TURN recommendations for Nuclear Operations were to be adopted by the [Commission] … PG&E would be required to reallocate funds from other utility functions in order to establish a safe and reliable operating budget for 2014 and the attrition years in 2015 and 2016."[1471] This is a spurious argument on several levels.

First, PG&E reallocated funding from Nuclear Operations since at least the TY 2011 GRC, and says it has operated Diablo Canyon safely and reliably since 2007 despite those reallocations.[1472] Second, PG&E has not even spent all the "imputed" amounts from the TY 2011 GRC, and as those were the result of a Settlement, they are necessarily lower than PG&E's original forecasts. Third, PG&E's 2012 forecasts have already proven to be, in nearly MWC, substantially over estimated.

[1467] Ex. 79 (DRA-11), p. 77.

[1468] Ex. 24 (PG&E-6), p. 3-30.

[1469] Ex. 79 (DRA-11), p. 77.

[1470] Ex. 79 (DRA-11), p. 77.

[1471] Ex. 58, p. 3-4, Q/A 6.

[1472] 26 RT 3097-3098, Halpin/ PG&E.

As the Liberty Consulting Group said in its report on PG&E's Electric Distribution System GRC filing, PG&E "… overuse[s] the safety label."[1473] The same is true here.

6.3.1.1 MWC AK—Manage Environmental Operations

PG&E forecasts $3.068 million for Major Work Category AK – Manage Environmental Operations. This is an increase of $0.601 million, or 24.36%, over its 2011 recorded adjusted expenses of $2.467 million. PG&E has a staffing level of four charging to MWC AK and this level is expected to stay the same in the Test Year.[1474] DRA's forecast of $2.467 million uses PG&E's 2011 recorded adjusted expenses as a basis.

PG&E's request for additional funding of $0.601 million over 2011 recorded adjusted expenses of $2.467 million is not justified based on historical expense levels. Nor has PG&E provided sufficient or complete information to support the increases on any other basis.

In discovery, DRA asked PG&E to provide a detailed breakdown of the calculation of the forecasted increase of $0.601 million, i.e., the calculation of each individual line item estimate included in the increase, and the supporting documentation to substantiate the estimates for each proposed project. PG&E provided a spreadsheet showing lump sum numbers, but not how it calculated each individual line item estimate over 2011 expense levels. Nor did PG&E provide the supporting documentation to substantiate the estimates.[1475]

PG&E says it is not planning to add any staff to current levels,[1476] and did not provide any verifiable documentation that its current funding level and embedded historical costs, for the same or similar activities as the ones proposed in the Test Year, are insufficient to address required maintenance work in the Test Year.

PG&E's 2011 recorded adjusted expenses for MWC AK of $2.467 million is also significantly less than PG&E's 2011 GRC "imputed" amount of $4.528 million.[1477] This is a 83.54% decrease from the imputed amount. PG&E's 2011 recorded adjusted expenses of $2.467

[1473] Ex. 168, Liberty Consulting Group, p. 14.

[1474] Ex. 24 (PG&E-6), p. 3-61.

[1475] Ex. 79 (DRA 11), p. 47 citing DRA-PG&E-098-TLG, Q. 8

[1476] Ex. 24 (PG&E-6), p. 63.

[1477] Ex. 79 (DRA 11), p. 11, Table 11-3. Imputed 2011 data from PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018.

million are $0.300 million less than PG&E's 2011 GRC budgeted amount of $2.767 million.[1478] PG&E says the decrease in expenses was due to lower costs for the annual fee for waste discharge requirements per the State Water Resources Control Board.[1479]

PG&E's expenses recorded in MWC AK fluctuated between 2007 and 2011. The five year average (2007-2011) is $2.484 million. The three year average (2009-2011) is $2.438 million. PG&E's 2008 recorded adjusted expenses of $3.509 million was the highest figure for the six year period (2007-2012). PG&E itself says its forecasted staffing level is expected to remain the same as its 2011 levels. DRA's estimate of $2.467 million using PG&E's 2011 expense levels is comparable to the three and five year averages for this Major Work Category, and DRA recommends the Commission adopt it.

6.3.1.2 MWC BP – Manage DCPP Business

PG&E forecasts $15.287 million for its Major Work Category BP – Manage DCPP Business expenses. This is an increase of $10.121 million, or 195.92%, over its 2011 recorded adjusted expenses of $5.166 million. PG&E's current staffing level for MWC BP is 63 and PG&E says it plans to increase the staffing level by four by 2013 "driven by the addition of the office of the [Chief Nuclear Officer] CNO".[1480] DRA forecasted $5.166 million using PG&E's 2011 recorded adjusted expenses as a basis.[1481]

PG&E's request for additional funding of $10.121 million is excessive, based on historical expense levels. Nor is the information PG&E provided sufficient to support the increases on any other basis.[1482] PG&E did not provide any verifiable documentation to show

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[1478] Ex. 79 (DRA-11), p. 48, footnote 84: PG&E's 2011 budgeted amount of $2.767 million is from PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018.

[1479] Ex. 79 (DRA-11), p. 48.

[1480] Ex. 24 (PG&E-6), p. 3-82.

[1481] Ex. 79 (DRA-11), p. 49.

[1482] Ex. 79 (DRA 11), p. 49 footnote 87: In DRA-PG&E-098-TLG, Q.6, DRA asked PG&E to provide a detailed breakdown of the calculation of the forecasted increase of $10.121 million (i.e., the calculation of each individual line item estimate included in the increase) and the supporting documentation to substantiate the estimates for each proposed project. PG&E provided a spreadsheet showing lump sum numbers which lacked the detail showing how it calculated each individual line item estimate over 2011 expense levels and also did not provide the supporting documentation to substantiate the estimates.

that its current funding level and embedded historical costs, for the same or similar activities as it proposes for the Test Year, are insufficient to address required maintenance work.

PG&E's recorded adjusted expenses for MWC BP declined from $7.573 million in 2007 to $5.166 million in 2011.[1483] This $5.166 million in 2011 recorded expenses is also a 90.40% decrease from PG&E's 2011 GRC "imputed" amount of $9.836 million.[1484] PG&E's recorded adjusted expenses for the years 2007-2011 for MWC BP have all been less than its imputed amount every year. PG&E's 2012 recorded adjusted expenses of $8.474 million are considerably less than its 2012 forecast of $13.661 million. PG&E's 2012 forecast was thus more than even PG&E considered necessary to address its actual 2012 work activities in MWC BP.

PG&E has received sufficient funding during 2007-2011 and has embedded historical funding that can be reallocated and used to address PG&E's proposed activities in the Test Year. DRA recommends the Commission adopt a forecast of $5.166 million, PG&E's 2011 expense level, as a reasonable estimate for the Test Year.[1485]

6.3.1.3 MWC BR – Operate DCPP Plant

PG&E forecasts $107.340 million for its Major Work Category BR – Operate DCPP Plant expenses. This is an increase of $19.209 million, or 21.80%, over its 2011 recorded adjusted expenses of $88.131 million. PG&E's current staffing level for MWC BR is 283,[1486] but PG&E says it plans to increase the staffing level to 300 in 2013 as part of its "DCPP hire in advance of the attrition program."[1487]

DRA forecasts $91.921 million using a three year average (2010-2012). DRA's forecast is $15.419 million less than PG&E's forecast, but $3.790 million more than PG&E's 2011 recorded adjusted expenses.[1488]

[1483] Ex. 79 (DRA-11), p. 49.

[1484] Ex. 79 (DRA-11), p. 1, Table 11-3.

[1485] Ex. 79, (DRA-11), p. 50.

[1486] Ex. 24 (PG&E-6), p. 3-59.

[1487] Ex. 24 (PG&E-6) p. 3-59.

[1488] Ex. 79 (DRA-11), p. 51.

PG&E's request for additional funding of $19.209 million is not justified by historical expense levels or adequately supported with sufficient and complete information on any other basis.[1489] PG&E's recorded adjusted expenses for MWC BR decreased by $6.997 million between 2010 and 2011, but increased each year between 2007 and 2010 from $78.650 million in 2007 to $95.128 million in 2010. This is an increase of $16.478 million between 2007 and 2010. The five year average (2007–2011) for the period is $86.715 million. PG&E's highest recorded expense for the six year period (2007-2012) was in 2010 of $95.128 million.

PG&E's forecasted 21.80% increase over 2011 levels is unreasonable based on historical percentage changes between 2007 and 2012. A summary of PG&E's percentage changes of the increases and decreases in expenses, which included two refueling outages in 2009, [1490] between 2007 and 2012 were as follows: a 3.2% increase between 2007 and 2008, a 11.36% increase between 2008 and 2009, a 5.18% increase between 2009 and 2010, a 7.94% decrease between 2010 and 2011, and a 4.96% increase between 2011 and 2012.

PG&E's 2011 recorded adjusted amount of $88.131 million is also considerably less than its 2011 GRC imputed amount of $113.594 million. Similarly, PG&E's 2012 recorded adjusted expenses of $92.503 million are less than its 2012 forecast of $95.213 million.[1491]

PG&E's historical expense levels and authorized funding have embedded costs associated with employee retirements and overtime costs that can be reallocated and used for its proposed activities. PG&E has been hiring in advance of attrition during the historical period[1492] and its expenses have not increased by 21.80% between 2007 and 2012. DRA's estimate of $91.921 million, using a three year average (2010-2012), is more than the five year

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[1489] Ex. 79 (DRA-11), p. 51, footnote 92 citing DRA-PG&E-098-TLG, Q.4. DRA asked PG&E to provide a detailed breakdown of the calculation of the forecasted $19.209 million increase (i.e., the calculation of each individual line item estimate included in the increase) and the supporting documentation to substantiate the estimates for each proposed project. PG&E provided a spreadsheet showing lump sum numbers which lacked the detail showing how it calculated each individual line item estimate over 2011 expense levels and also did not provide the supporting documentation to substantiate the estimates.

[1490] Ex. 79 (DRA-11), p. 51, footnote 93: DRA-PG&E-098-TLG, Q.4-a. PG&E's forecast includes $6.610 million for two unit refueling outages in 2014.

[1491] Ex. 79 (DRA-11), p. 52.

[1492] Ex 22 (PG&E-6), p. 3-30.

average (2007-2011) of $86.715 million. DRA recommends the Commission adopt $91.921 million as a reasonable estimate for the Test Year for this MWC.

In Rebuttal, PG&E says that, among other things, DRA's estimate is flawed due to "a failure to include 2009 in the historical data which completely missed the year with a second refueling outage." PG&E is wrong. As noted above, DRA did consider 2009 and, in fact, DRA's estimate of $91.921 million is more than PG&E's recorded 2009 costs of $90.444 million.

In Rebuttal, PG&E also says DRA failed to consider the change in accounting for Security and other costs. As discussed above, by using an average of the years 2010, 2011 and 2012, DRA's estimate does include costs both from before and after the accounting change.[1493]

6.3.1.4 MWC BS – Maintain DCPP Plant Assets

PG&E forecasts $184.178 million for its Major Work Category BS – Maintain DCPP Plant Assets expenses. This is an increase of $73.704 million, or 66.72%, over its 2011 recorded adjusted expenses of $110.474 million. DRA forecasts $141.184 million using a five year average (2007-2011) plus incremental funding as a basis for its estimate. The five year average is $136.274 million; the incremental funding DRA recommends is $4.910 million.[1494]

PG&E's request for additional funding of $73.704 million is not justified based on historical expense levels. PG&E's current staffing level for MWC BS is 354.[1495] PG&E says it plans to increase the staffing level to 391 in 2014 as part of its aging workforce initiative.[1496] For the reasons discussed above, DRA recommends the Commission reject additional ratepayer funding of 37 new positions since PG&E's ratepayers are already funding this program, and have been for years.[1497]

PG&E did not provide verifiable documentation to support and justify its calculated estimates for additional funding of $11.500 million ($34.500 million over three years) for Fukushima Daiichi Nuclear Regulatory Commission (NRC) Rulemaking, $2.932 million

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[1493] See Section 6.3.1 of this Opening Brief, above.

[1494] Ex. 79 (DRA-11), p. 53.

[1495] Ex. 24 (PG&E-6), p. 3-61.

[1496] Ex. 24 (PG&E-6), p. 3-61.

[1497] See Section 6.3.1 of this Opening Brief, above.

($8.796 million over three years) for Re-wedge Main Generator project, and $0.300 million ($0.900 million over three years) for its Large Motor Rewind project.[1498]

DRA normalized PG&E's incremental request over the three year rate cycle and recommends an additional $3.833 million for Fukushima Daiichi NRC Rulemaking, $0.977 million for Re-wedge Main Generator project, and $0.100 million for the Large Motor Rewind project.

DRA opposes additional ratepayer funding over 2011 expense levels for PG&E's proposed projects for Water Storage Water Tank Concrete Removal of $1.840 million, Concrete Repair Program of $1.121 million, Repair Concrete CWT 11 & 12 of $0.709 million, Repair Intake Concrete of $0.371 million, Repair Discharge Structure Concrete of $0.530 million, Underground Cable/Conduit Program of $0.625 million, Anion Resin Tank Liners of $1.029 million, License Basis Verification of $1.519 million, Procedures Upgrade Project of $2.970 million, Implement Emergency Planning of $1.453 million, Implement Cybersecurity of $1.608 million, and Write off of Material Obsolescence[1499] of $3.0 million.

PG&E's recorded adjusted expenses in MWC BS fluctuated significantly between 2007 and 2011. These expenses increased from $140.795 million in 2007, to $158.387 million in 2009, but declined each year between 2009 and 2011, going from $158.387 million in 2009, to $110.474 million in 2011, or 43.37%.

The five-year average (2007–2011) for the period is $136.274 million, and the three year average (2009-2011) is $128.303 million. PG&E's highest recorded figure for the six year period (2007-2012) was in 2009 of $158.387 million. In response to a data request, PG&E states "Please note that 2009 had two refueling outages increasing labor approximately $11.0 million

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[1498] Ex. 79 (DRA-11), p. 53, citing DRA-PG&E-098-TLG, Q.5 and DRA-PG&E-205-TLG, Q.1. DRA asked PG&E to provide a detailed breakdown of the calculation of the forecasted increase (i.e., the calculation of each individual line item estimate included in the increase) and the supporting documentation to substantiate the estimates for each proposed project. PG&E provided spreadsheets showing line items with lump sum numbers, but they lacked the detail showing how it calculated each individual line item estimate over 2011 expense levels. Nor did PG&E provide the supporting documentation to substantiate the estimates.

[1499] Ex. 24 (PG&E-6), p. 3-34. PG&E's write-off of obsolete inventory has fluctuated over the last six years (2007-2012) with an average for the period of $1.015 million (DRA-PG&E-205-TLG supplemental response to question 4). PG&E included a request for additional funding for this project in its 2011 GRC. PG&E's states in regards to a $3.542 million decrease in its 2011 Imputed expense levels: "Decrease is due to accelerating the evaluation of inventory items for obsolescence".

for this MWC. 2010 reflected significant increases in Security costs (allocated partially to this MWC in 2010) due to new NRC requirements and as reflected in headcount #s..."[1500]

PG&E's 2011 recorded adjusted expenses for MWC BS of $110.474 million is $6.373 million less than PG&E's 2011 GRC imputed amount of $116.847 million.[1501] In fact, PG&E's recorded adjusted expenses for the years 2009-2011 have been less than its imputed amounts each year. PG&E's 2009 recorded adjusted amount of $158.387 million was $16.215 million less than its 2009 imputed amount of $174.602 million. PG&E's 2010 recorded adjusted expenses of $116.047 million is also less than its 2010 imputed amount of $143.562 million.[1502]

PG&E's forecast for MWC BS includes incremental funding of $2.731 million for four concrete repair projects (Concrete Repair Program, Repair Concrete CWT 11 & 12, Repair Intake Concrete and Repair Discharge Structure Concrete) that are on-going, normal and/or routine maintenance work that already have embedded historical costs from completed concrete projects that are the same or are similar to the proposed Test Year projects.[1503] The funding from these completed concrete projects can be reallocated and used for concrete projects PG&E proposes for the Test Year.[1504] PG&E states that "[t]he purpose of the Concrete Repair Program is to repair and/or replace damaged structural concrete on an on-going defensive programmatic manner in order to restore the plant structures to their as-designed configuration".[1505]

PG&E's forecast also includes funding of $10.917 million for six proposed projects (Water Storage Water Tank Concrete removal, Underground Cable/Conduit Program, Anion Resin Tank Liners, Procedures Upgrade Project, Implement Emergency Planning and Write-Off

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[1500] Ex. 79 (DRA-11), p. 55, citing DRA-PG&E-098-TLG, Q.5-c.

[1501] Ex. 79 (DRA-11), p. 56, footnote 100: Imputed 2011 data from PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018.

[1502] Ex. 79 (DRA-11), p. 56.

[1503] Ex. 28 (PG&E-6, workpapers) p. WP 3-44 to WP 3-60.

[1504] Ex. 79 (DRA-11), p. 56, footnote 102: PG&E provided a document that included the history of its concrete repair projects and associated costs for the period 2006-present (DRA-PG&E-205-TLG Q.1-a-f). The historical concrete projects are very similar to its proposed Test Year concrete projects.

[1505] Ex. 24 (PG&E-6), p.3-26.

of material obsolescence)[1506] that were included in its 2011 GRC funding request but were deferred. PG&E is now asking for funding a second time for the same projects.

Regarding deferred maintenance projects, PG&E's testimony states "Some of the projects that were initially proposed during [the] 2011 rate case period have not been completed or were rescheduled to the 2014 rate case timeframe. Others were planned to start in the 2011 GRC timeframe and continue into the 2014 GRC window".[1507]

PG&E's ratepayers should not be required to fund this routine and on-going maintenance work twice because PG&E either deferred the work or did not incorporate historical embedded cost for on-going projects into its Test Year forecast. PG&E had 2012 and 2013 to complete these proposed on-going or deferred projects before the 2014 Test Year.

As noted above in Section 6.2 of this Brief, in connection with PG&E's Hydro Operations, the Commission's long-standing policy is that it is the utility's shareholders, not its ratepayers who are responsible for additional costs associated with deferred maintenance.[1508]

In examining the relationship between embedded historical costs and forecast expenses for the same or similar activities, the Commission has stated:

> SCE's forecast also includes a $4.812 million (constant 2006$) increase for insulator replacement as part of its Transmission Life Extension Program. SCE claims that the increase represents the cost of materials and the use of contract crews to supplement SCE's crews for insulator and hardware replacements. DRA claims historical expenses have embedded costs for insulator replacements. According to SCE, some of the circuits it will be replacing are over 90 years old and many of the insulators on its system have exceeded their life expectancies. While these types of programs may be a cost-effective way to maintain the integrity of the system and slow the deterioration of capital assets, SCE has not sufficiently addressed the relationship of these programs to costs embedded in historical data. Accordingly, SCE's request for $4.812 million to increase its insulator replacement as part of its Life Extension Program is denied.[1509]

[1506] Ex. 24 (PG&E-6), pp.3-27 and 3-28, DRA-PG&E-205-TLG, Q.1-j-ii and PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018.

[1507] Ex. 24 (PG&E-6), p. 3-25.

[1508] 10 CPUC 2d, 155, 186 (D.82-12-055); D.09-03-025.

[1509] D.09-03-025, p. 72.

PG&E was authorized sufficient funding during 2007-2011 and has embedded funding that can be used for the activities PG&E's proposes in the Test Year. DRA recommends that the Commission adopt $141.184 million as its forecast, using a five year average (2007-2011) of $136.274 million, plus incremental funding of $4.910 million.[1510]

6.3.1.5 MWC BT – Enhance DCPP Personnel Performance

PG&E forecasts $23.536 million for its Major Work Category BT – Enhance DCPP Personnel Performance expenses. This is an increase of $7.405 million, or 45.91%, over its 2011 recorded adjusted expenses of $16.131 million. DRA forecasts $16.131 million using PG&E's 2011 recorded adjusted expense.[1511]

PG&E's current staffing level for MWC BT is 106. PG&E says it plans to increase the staffing level by 6 as part of its aging workforce initiative.[1512] For the reasons discussed above in Section 6.3.1., DRA recommends the Commission reject any additional ratepayer funding for PG&E's "aging workforce" argument.

PG&E's recorded adjusted expenses for MWC BT fluctuated slightly between 2007 and 2011. The five year average (2007-2011) is $14.612 million and the three year average (2009-2011) is $14.574 million.

PG&E did not provide any verifiable documentation that demonstrated that its current funding level and embedded historical costs for the same or similar activities as proposed in the Test Year, are insufficient to address required maintenance work. PG&E's recorded adjusted expenses for the years 2007-2010 for MWC BT have been less than its imputed amount each year.[1513] PG&E's 2012 recorded adjusted expenses of $15.975 million are $3.374 million less than its 2012 forecast of $19.349 million. PG&E has requested more funding than necessary to address its work activities in MWC BT.

PG&E was authorized sufficient funding during 2007-2011 and has embedded funding that can be reallocated and used to address PG&E's proposed activities in the Test Year. DRA's

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[1510] Ex. 79 (DRA-11), p. 60.

[1511] Ex. 79 (DRA-11), p. 61.

[1512] Ex. 24 (PG&E-6), p. 3-64.

[1513] Ex. 79 (DRA-11), p. 62, footnote 122: Imputed 2011 data from PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018.

estimate of $16.131 million, using PG&E's 2011 expense levels, is more than the five year and three averages.[1514]

In Rebuttal, PG&E criticizes DRA's forecast for the usual reasons of "failing to consider PG&E's accounting changes" and escalation addressed above, and also failure to consider NRC regulatory fees for Fukushima rulemaking."[1515] DRA did not "fail to consider" the Fukushima rulemaking; DRA disagrees with PG&E's forecast for it.

PG&E forecasts $11.500 million ($34.500 million over three years) for is Fukushima Daiichi project. In Direct testimony, PG&E makes a number of generalizations about the Fukushima rulemaking, and then says "… PG&E is presently unable to predict with certainty the ultimate costs to be incurred in 2013- 2016 associated with meeting the additional requirements to be imposed by the NRC to enhance safety…."[1516] In fact, PG&E's Direct testimony offers no verifiable information to support at all for its forecast. DRA, therefore, recommends normalizing PG&E's forecast of $11.500 million over the three year rate case cycle for a Test Year estimate of $3.833 million.[1517]

DRA, therefore, continues to recommend that the Commission adopt $16.131 million, using PG&E's 2011 expense level, as a reasonable estimate for the Test Year.[1518]

6.3.1.6 MWC BV – Maintain DCPP Plant Configuration

PG&E forecasts $70.238 million for its Major Work Category BV – Maintain DCPP Plant Configuration expenses. PG&E's forecast is an increase of $22.551 million, or 47.29%, over its 2011 recorded adjusted expenses of $47.687 million. PG&E's forecast includes $11.818 million ($35.454 million over three years) for two unit refueling outages and $5.0 million ($15.0 million over three years) for steam generator eddy current inspections.[1519]

[1514] Ex. 79 (DRA-11), p. 62.

[1515] Ex. 58 (PG&E21), p. 3-45.

[1516] Ex. 24, p. 3-87, lines 15-18.

[1517] Ex. 79 (DRA-11), p. 74.

[1518] Ex. 79 (DRA-11), p. 62.

[1519] Ex. 79 (DRA-11), p. 62 citing DRA-PG&E-098-TLG, Q.7. DRA's forecast for MWC BV of $52.751 million includes incremental funding of $5.064 million over 2011 recorded adjusted expenses. DRA's incremental funding of $5.064 million is reasonable and is comparable to the normalized amount of PG&E's forecast of $11.818 million for its two unit refueling outages and the normalized forecast of $5.0 million for PG&E's steam generator eddy current inspections of $5.606 million ($11.818 million plus

DRA forecasts $52.751 million using a three year average (2009-2011) as a basis for its estimate. DRA's forecast is $17.487 million less than PG&E's Test Year forecast but $5.064 million more than PG&E's 2011 recorded adjusted expenses.[1520]

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 or on any other basis.[1521] PG&E's recorded adjusted expenses for MWC BV fluctuated between 2007 and 2011. This fluctuation was due, in part, to PG&E's two refueling outages in 2009 that caused expenses to increase between 2008 and 2009. The five year average (2007-2011) is $44.618 million and the three year average (2009-2011) is $52.751 million.[1522]

PG&E did not provide verifiable documentation to demonstrate that its current funding level and embedded historical costs (for the same or similar activities as those proposed in the Test Year) are insufficient to address required maintenance work in the Test Year. PG&E's 2011 recorded adjusted expenses for MWC BV of $47.687 million are $8.193 million less than PG&E's 2011 GRC imputed amount of $55.880 million.[1523] This is a 17.18% decrease from the imputed amount. PG&E's recorded adjusted expenses for the years 2007-2011 for MWC BV have been less than its imputed amount each year and PG&E has requested more funding than necessary to address its work activities in MWC BV.

These excessive funding requests are burdensome to ratepayers. PG&E was authorized sufficient funding during 2007-2011 and has embedded historical funding from closed and completed projects that can be reallocated and utilized to address PG&E's proposed activities

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$5.0 million divided by three years equals $5.606 million).

[1520] Ex. 79 (DRA-11), p. 63.

[1521] Ex. 79 (DRA-11), p. 63, footnote 125 citing DRA-PG&E-098-TLG, Q.7. DRA asked PG&E to provide a detailed breakdown of the calculation of the forecasted increase (i.e., the calculation of each individual line item estimate included in the increase) and the supporting documentation to substantiate the estimates for each proposed project. PG&E provided a brief one page spreadsheet showing line items for labor costs, material, contract, refueling outage, and other as lump sum numbers which lacked the specific detail showing exactly how PG&E calculated each individual line item estimate included in the forecasted increase over 2011 expense levels and also did not provide the supporting documentation to substantiate the estimates for each proposed project.

[1522] Ex. 79 (DRA-11), p. 63.

[1523] Ex. 79 (DRA-11), p. 64: Imputed 2011 data is from PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018.

(i.e., two unit refueling outages, steam generator eddy current inspections, additional staffing, etc.) in the Test Year.

DRA's estimate of $52.751 million, using a three year average, is more than the five year average and PG&E's 2011 recorded adjusted expenses. DRA recommends the Commission adopt a forecast of $52.751 million for this Major Work Category.[1524]

6.3.1.7 MWC BQ – DCPP Support Services/ Loss Prevention

PG&E forecasts $46.353 million for its MWC BQ – DCPP Support Services/Loss Prevention expenses. PG&E's forecast is an increase of $4.209 million, or 9.99%, over its 2011 recorded adjusted expenses of $42.144 million. DRA forecasts $11.355 million for MWC BQ using a five year average as a basis for its estimate. DRA's forecast is $34.998 million less than PG&E's forecast.

PG&E's request is not justified based on historical expense levels, or on any other basis.[1525] PG&E's current staffing level for MWC BQ is 306.[1526] PG&E plans to reduce the level by nine due to the completion of security projects.[1527]

PG&E's recorded adjusted expenses for MWC BQ increased by $2.360 million between 2007 and 2010 with an average for the four year period of $3.658 million. PG&E's recorded expenses increased between 2010 and 2011 by $37.180 million from $4.964 million in 2010 to $42.144 million in 2011. The increase in expenses between 2010 and 2011 was due in part to PG&E's change in the accounting of its Security Support costs and Facility charges.[1528] The five year average (2007-2011) is $11.355 million.

[1524] Ex. 79 (DRA-11), p. 64.

[1525] Ex. 79 (DRA-11), p. 65, footnote 129: In response to DRA-PG&E-098-TLG, Q.10, PG&E provided a spreadsheet showing line items for labor costs, material, contract, and other as lump sum numbers which lacked the specific detail showing exactly how PG&E calculated each individual line item estimate over 2011 expense levels and also did not provide the supporting documentation to substantiate the estimates.

[1526] Ex. 24 (PG&E-6), p. 3-77.

[1527] Ex. 24 (PG&E-6), p. 3-77.

[1528] Ex. 79 (DRA-11), p. 65, footnote 130: Regarding PG&E's Facility charges, beginning in 2011 PG&E allocated the costs incurred to various MWCs instead of directly charging MWC BS. (DRA-PG&E-098-TLG).

In 2011, PG&E changed the way it had charged Security costs among various other Major Work Categories, and began to direct charge MWC BQ for those expenses.[1529] This shifting of costs between MWCs caused the large increase of $37.180 million in MWC BQ between 2010 and 2011, and caused decreases in MWCs BV, BS, and BR between 2010 and 2011. The expense decrease in these MWCs due to this accounting change between 2010 and 2011 totaled $22.258 million.[1530] However the increase between 2010 and 2011 in MWC BQ was $37.180 million, a difference of $14.992 million. PG&E's recorded adjusted expenses for MWCs BV, BS, and BR for 2007-2010 include embedded expenses for Security Support costs which DRA reviewed during its analysis of PG&E's Test Year expense request for these MWCs.

DRA used PG&E's recorded data to calculate its Test Year estimates for MWCs BQ, BV, BS, and BR, which included Security Support costs. PG&E should have identified and removed all costs incurred for Security Support from MWCs BV, BS, and BR for 2007-2010 prior to calculating its forecast in its 2014 GRC. Since PG&E did not do so, DRA used a different methodology from PG&E to forecast each of PG&E's Nuclear MWCs, and the forecasted costs for PG&E's Security Support costs included in the various MWCs are incorporated in DRA's estimates.[1531]

PG&E's recorded adjusted expenses for the years 2007-2010 for MWC BQ have been less than its Imputed amount each year before the change in accounting for expenses reflected in the 2011 expense level.[1532] Based on a review of PG&E's recorded and imputed amounts for the

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[1529] Ex. 79 (DRA-11), p. 66, citing DRA-PG&E-098-TLG, Q.10.

[1530] Ex. 79 (DRA-11), p. 66, footnote 132: The expense decrease between 2010 and 2011 for MWC BV is $9.688 million, for MWC BS, the decrease between 2010 and 2011 is $5.573 million, and for MWC BR the expense decrease between 2010 and 2011 is $6.997 million. PG&E did not provide verifiable documentation that clearly identified the Security cost adjustments or the specific cause of the expense decrease between 2010 and 2011 for MWCs BV, BS, and BR or provide documentation on the specific cause of the expense increase between 2010 and 2011 in MWC BQ.

[1531] Ex. 79 (DRA-11), p. 66.

[1532] Ex. 79 (DRA-11), p. 67, footnote 133: Imputed 2011 data from PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018. The accounts impacted by the Security Cost allocation change were MWCs BV, BS, and BR. These MWCs are no longer being charged for Security Cost as of 2011. The recorded adjusted expenses recorded for MWC BV for 2007-2011 were less than the Imputed amount each year. MWC BS recorded adjusted expenses for 2009-2011 were lower than the Imputed amount. The recorded adjusted expenses in MWC BR were higher than the Imputed amount for 2007-2010. The 2011 recorded adjusted expenses for MWC BR was less than the 2011 GRC Imputed amount.

MWCs impacted by the accounting change, PG&E requested more than was necessary to address its work activities during 2007-2011, especially in MWC BQ.

PG&E's excessive funding requests are burdensome to ratepayers. PG&E has received sufficient authorized funding during 2007-2011 and has embedded historical funding that can be reallocated and used to address PG&E's proposed activities in the Test Year. DRA's estimate of $11.355 million utilizing a five year average is a reasonable estimate for the Test Year and addresses the fluctuations in recorded expenses for MWC BQ.

6.3.1.8 MWC JV – Maintain Information Technology Applications and Infrastructure

> PG&E forecasts $2.9 million for its Major Work Category JV – Maintain IT Applications and Infrastructure expenses. PG&E's forecast is an increase of $1.125 million, or 63.38%, over its 2011 recorded adjusted expenses of $1.775 million. PG&E developed its 2014 forecast for MWC JV using inputs from PG&E's Concept Estimating tool.[1533] PG&E's proposal includes costs to implement and deploy infrastructure systems and software applications.[1534] DRA forecasts $1.808 million using a three year average (2009-2011) as the basis for its estimate. DRA's forecast is $1.092 million less than PG&E's forecast.

PG&E's request for additional funding of $1.125 million is not justified based on historical expense levels or on any other basis. PG&E's recorded adjusted expenses for MWC JV fluctuated between 2007 and 2011. The five year average (2007-2011) is $1.757 million and the three year average (2009-2011) is $1.808 million.

[1533] DRA's concerns about PG&E's IT Concept Estimating tool are discussed below in Section 7 of this Opening Brief.

[1534] Ex. 24 (PG&E-6), p. 3-31. PG&E's proposed IT projects also have an associated capital forecast.

> DRA opposes additional ratepayer funding over 2011 recorded expense levels of $0.300 million ($0.900 million over three years) for Electric Document Management System (EDMS) to Documentum Migration,[1535] $0.300 million ($0.900 over three years) for Linear Asset Management,[1536] and $0.350 million ($1.050 million over three years) for SAP Application Consolidation, Enhancement and Integration projects in the Test Year to address PG&E's Nuclear Operations recordkeeping and document management deficiencies.[1537] The activities included in PG&E's proposals mentioned above 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.[1538] In support for its proposal, PG&E states the following:
>
> > In a manner analogous to the gas business, it is imperative that the nuclear facility have the ability to tie exact locations to linear assets and to understand and represent those assets as sub-elements of larger continuous systems. When testing, maintenance or inspection is done at a physical location, resulting work records must reflect the linear asset sub-element on which the work was performed and must allow PG&E the ability to mine the work records to identify those sub-elements on which work was performed.[1539]

The Commission should reject PG&E's request. DRA agrees with PG&E that, "[i]n a manner analogous to the gas business, it is imperative that the nuclear facility have the ability to

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[1535] Ex. 79 (DRA-11), p. 69: PG&E's Electric Document Management System (EDMS) to Documentum Migration project includes migrating PG&E's legacy content management system to a new enterprise platform for "more and rigorous record keeping of documents, procedures, correspondence and drawings". (Ex. 24 (PG&E-6), p. 3-48).

[1536] Ex. 79 (DRA-11), p. 69: PG&E's Linear Asset Management project implements the SAP module for Linear Asset Management for DCPP piping and conduit and other linear-type assets and will leverage the work currently being done in its Gas Operations. This project will integrate with Documentum and with the Geographic Information System (GIS) to record the specific location along a linear asset of the maintenance, testing and project work performed so the exact location is documented. (Ex. 24 (PG&E-6), p. 3-53).

[1537] Ex. 79 (DRA-11), p. 69: PG&E's request for additional funding for implementation of Electric Document Management system (EDMS) to Documentum Migration, Linear Asset Management and SAP Application Consolidation, Enhancement and Integration projects for MWC JV to address its recordkeeping deficiencies is similar to its proposal in its Pipeline Safety Enhancement Plan (PSEP) regarding its Pipeline Records Integration Program (PRIP). In the PSEP proceeding, PG&E requested incremental ratepayer funding for collecting, reviewing, organizing, and verifying critical records associated with its installed gas pipeline segments and for additional funding to upgrade and consolidate its multiple existing Information Technology systems (SAP and Geographic Information System (GIS)). The Commission rejected PG&E's PRIP proposal. (See D.12-12-030 p. 87).

[1538] Ex. 79 (DRA-11), p. 70.

[1539] Ex. 24 (PG&E-6), p. 3-53 and 3-54.

tie exact locations to linear assets…" Consequently, PG&E has received ratepayer funding in the historical years to ensure that its recordkeeping and document storage programs associated with its nuclear operations were maintained.

The Commission's statements in PG&E's Pipeline Safety Enhancement Plan regarding its Pipeline Records Integration Program and PG&E's natural gas transmission system,[1540] also apply to PG&E's nuclear facility in that PG&E became responsible for its nuclear system the day it installed facilities and equipment for the system. PG&E's "responsibility includes creating and maintaining records of the location and engineering details of system components."[1541] If PG&E had used authorized funding effectively to ensure that its nuclear records management systems were properly corrected, updated, organized and maintained, PG&E would not be requesting incremental funding in the Test Year for these recordkeeping activities. It is unreasonable for PG&E to request additional ratepayer funding to address its deficiencies.

PG&E had 2012 and now has 2013 to address its proposed activities in this MWC before the Test Year. DRA recommends that the Commission adopt a forecast of $1.808 million, using a three year average, for the Test Year.[1542]

6.3.2 Capital Expenditures

For capital expenditures in Nuclear Operations, PG&E requests $266.6 million for 2012, $216.2 million for 2013 and $254.6 million for TY 2014 (nominal dollars). DRA's forecasts for Nuclear Operations capital expenditures are $267.0 million for 2012, $215.7 million for 2013 and $253.0 million for TY 2014. DRA's adjustments to Nuclear Operations are proposed for the IT projects in MWC 2F (Nuclear). Otherwise, DRA accepts PG&E's expenditure request for Nuclear Operations.

6.3.2.1 2012 Nuclear Operations Capital Forecast

DRA adopts the 2012 recorded capital expenditures for the 2012 forecast for Nuclear Operations capital. This will result in a $3.6 million decrease from PG&E's forecast to $267.0 million.[1543]

[1540] See D.12-12-030, p. 87, regarding PG&E's Pipeline Safety Enhancement Plan and its Pipeline Records Integration Program.

[1541] See D.12-12-030, p. 87.

[1542] Ex. 79, (DRA-11), p. 71.

6.3.2.2 2013 Nuclear Operations Capital Forecast

DRA accepts PG&E's 2013 forecast for Nuclear Operations capital except for the IT projects in MWC 2F. As discussed in Section 7 of this Opening Brief, DRA recommends that only 86% of the planned MWC 2F budgets should be adopted for the forecast. DRA recommends that PG&E's MWC 2F (Nuclear) for 2013 be decreased by $0.57 million. Based on review of PG&E's testimony and workpapers, DRA accepts all other elements of PG&E's forecast.[1544]

6.3.2.3 2014 Nuclear Operations Capital Forecast

DRA accepts PG&E's 2014 forecast for Nuclear Operations capital except for the IT projects in MWC 2F. As discussed in Section 7 of this Opening Brief, DRA recommends that 86% of PG&E's planned MWC 2F budgets be adopted for the forecast budgets. DRA recommends that PG&E's MWC 2F (Nuclear) for 2014 be decreased by $1.6 million, which also results in a total adjustment to the 2014 Nuclear capital forecast of $1.6 million.[1545]

6.3.3 Balancing Account

6.3.3.1 Expenses

PG&E's forecast includes a proposal to establish a two-way balancing account for the Nuclear Regulatory Commission (NRC) rulemaking processes already in progress for projects associated with Fukushima Daiichi Nuclear Station Rulemaking, Cybersecurity and Emergency Planning.[1546] DRA opposes PG&E's request to establish a two-way balancing account for these projects.[1547]

[1543] Ex. 80 (DRA-12), p. 20.

[1544] Ex. 80 (DRA-12), p. 20.

[1545] Ex. 80 (DRA-12), p. 20.

[1546] Ex. 24 (PG&E-6), p. 3-2, 3-84, and p. 3-92. See Ex.PG&E-6, workpapers p. WP 3-51 and WP 3-53 for PG&E's forecast for its proposed Emergency Planning project of $1.453 million and its Cybersecurity projects of $1.608 million recorded to MWC BS.

[1547] Ex. 79 (DRA-11), p. 72.

PG&E's justification is that "it is difficult to estimate the cost and timing of the impacts of the new NRC rules."[1548] When asked how long PG&E had been aware of the proceedings for which it now seeks a balancing account, PG&E's response was:

> PG&E became aware that the NRC was preparing the Emergency Planning Rulemaking in early 2009; however, the final rule-making was not issued until November 2011. PG&E has been aware of the NFPA 805 Rulemaking since mid-2004; however, the final requirements for the transition were to be determined following the completion of programs at two pilot plants which were not completed until December 2010. NRC input on review of the DCPP Seismic Probabalistic [sic] Risk Assessment was provided in April 2011. PG&E has been aware of the Cybersecurity Rulemaking since early 2009; however the final rule-making was not completed until April 2011.[1549]

PG&E's 2011 GRC included funding for its Cybersecurity project, but PG&E deferred this project due to a revision of PG&E's project schedule.[1550] As PG&E incurs costs for on-going Cybersecurity and Emergency Planning projects, these costs are included in historical expenses that can be reallocated and used for the same or similar activities.[1551] PG&E's Fukushima Daiichi project is a new regulatory requirement which started in 2012. In 2012 PG&E incurred $2.2 million for the Fukushima project. PG&E has been able to record costs associated with these projects in MWC BS[1552] and did not identify specific problems or explain why it cannot continue to do so.

6.3.3.2 Capital

PG&E proposes a new two-way Diablo Canyon Regulatory Balancing Account to address the uncertainty of cost recovery for capital items that may be necessary due to regulatory requirements imposed by the Nuclear Regulatory Commission (NRC).[1553] Cost recovery is

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[1548] Ex. 22 (PG&E-6), p. 3-84.

[1549] Ex. 79 (DRA-11), p. 73.

[1550] Ex. 79 (DRA-11), p. 74, footnote 146: PG&E's August 3, 2011 Budget Report in Compliance with D.11-05-018 and DRA-PG&E-205-TLG, Q.1-j-ii.

[1551] Ex. 79 (DRA-11), p. 74, footnote 145: PG&E established budgets of $1.9 million in 2011 from its 2011 GRC funding with a forecasted total spend of $4.2 million between 2011-2013 for its Cybersecurity project. (DRA-PG&E-205-TLG, Q.1-j-ii).

[1552] Ex. 79 (DRA-11), p. 73

[1553] Ex. 24 (PG&E-6), pp. 3-90-3-91.

uncertain due to the difficulty in forecasting potential new regulatory requirements between General Rate Cases, according to PG&E. A two-way balancing account would ameliorate this problem, PG&E argues, by allowing the company to recover any revenue requirement not currently in rates if unforeseen (at the time of the General Rate Case forecast) costs are imposed. The two-way feature would also have the utility return unspent funds which would have been collected in rates but turned out to be unnecessary for the identified programs.[1554]

The two-way balancing account is unnecessary and should be rejected. The uncertainty of NRC actions discussed by PG&E has not materialized. Without any evidence of an actual problem, there is no justification for creating a separate, special "bucket" of capital budgets for potential new NRC mandates. PG&E has addressed NRC regulatory requirements for the life of DCPP and has managed to balance safety needs, reliability, NRC uncertainty, and rate recovery without any previously reported problem. The three-year rate case cycle for request and approval of the Nuclear Operations capital budgets should be sufficient without a two-way balancing account for certain projects. If and when there becomes a particular problem, PG&E can make a request through a special application.

6.4 Fossil and Other Generation Operations Costs

PG&E's other generating assets in ES are three gas fired power plants, Gate Generating Staton, Calusa Generating Station and Humboldt Generating Station, all built between 2009 and 2010, seven ground-mounted photovoltaic (PV) solar stations and two fuel cell facilities . ES O&M expenses for PG&E's fossil and alternative fuel facilities are forecast in 8 MWC, but taken together in two groups of Fossil O&M Expense and Other Gen O&M Expense, PG&E's TY 2014 forecasts are $54.052 million and $1.581 million respectively, for a total of $54.633 million in TY 2014. This TY 2014 Fossil and Other Generation forecast exceeds recorded costs for 2011 by 18 percent. The 2011 recorded costs as $45.786 million.

DRA summarized the MWC breakdown of PG&E's TY 2014 O&M expense forecasts for fossil and other generation in Table 11-27 of its Report, as follows:

[1554] PG&E identifies the four program categories for capital expenditures in Ex. 24, p. 3-91, Table 3-8.

Table 11-27
Energy Supply Expenses for TY2014
Fossil and Other Generation Operations
(In Thousands of Dollars)

Description (a)	PG&E Proposed[1555] (b)	DRA Recommended (c)
AK- Manage Environmental Operations	$3,204	$3,204
KK- Operate Fossil Generation	$14,858	$12,935
KL- Maintain Fossil Generating Equipment	$31,942	27,045
KM- Maintain Fossil Buildings, Grounds, and Infrastructure	$3,048	$2,247
KQ- Operate Alternative Generation	$364	$60
KR- Maintain Alternative Gen Generating Equipment	$1,109	$1,109
KS- Maintain Alternative Generation Buildings, Grounds, and Infrastructure	$108	$6
Total	$54,633	$46,606

Ex. 79 (DRA-11), p.78.)

PG&E claims that the MWCs driving the 2014 increase for fossil, PV, and fuel cell O&M expenses over 2011 recorded costs are primarily MWC KK – Operate Fossil Generation and MWC KL – Maintain Fossil Generation. MWC KK increased from TY 2011 recorded cost to TY 2014 forecast estimates as a result of the implementation of a document storage program, an increase in staffing at HBGS, and work that was transferred from other MWCs[1556], while MWC KL increased due to implementation of a piping integrity program, implementation assessment program, implementation of a material traceability program and major engine prevention maintenance at the Humboldt Generating Station. Table 11-28 from DRA's Report reflects PG&E's recorded costs and forecast estimates for all Fossil and Other Generation MWC from 2007 through this TY 2014 GRC.

[1555] Ex. 24 (PG&E-6), p. WP 4-1.

[1556] Ex. 24 (PG&E-6), p. WP 4-4.

Table 11-28[1557]
2007-2012 Recorded and 2014 Forecast Data for MWCs included in Fossil and Other Generation Operations (in Thousands of Dollars)

Description	2007	2008	2009	2010	2011	2012	2014
AB- Support	$97	$68	$79	($0)	($0)	$6	$0
AK- Manage Environmental Operation	$734	$850	$1,472	$1,649	$3,894	$2,655	$3,204
KK- Operate Fossil Generation	$6,011	$6,086	$10,249	$9,907	$12,341	$13,529	$14,858
KL- Maintain Fossil Generating Equipment	$4,028	$4,480	$13,374	$12,510	$27,045	$42,094	$31,942
KM- Maintain Fossil Bldg Grnd Infrst	$191	$287	$770	$846	$2,015	$2,479	$3,048
KQ- Operate Alternative Gen	$0	$0	$0	$0	$0	$60	$364
KR- Maintain Alt Gen Generating Equipment	$2	$35	$23	$108	$492	$1,206	$1,109
KS- Maintain Alt Gen Bldg Grnd Infrast	$0	$0	$0	$0	$0	$6	$108
Total	$11,063	$11,806	$25,967	$25,020	$45,787	$62,035	$54,633

6.4.1 Expense

DRA reviewed PG&E's application, including the testimony, workpapers, data request responses and historical expense levels for these MWCs and did not take issue with MWC Ak – Manage Environmental Operations and MWC KR – Maintain Alternative Gen Generating Equipment. Thus, DRA will not address MWC AK and KR in this opening brief. DRA made adjustments to other MWCs in the following discussion.

6.4.1.1 MWK KK – Operate Fossil Generation

PG&E's TY 2014 forecast for MWC KK is $14.8598 million, which is 20.4 percent more than the $12.341 million of recorded expense for the same category in 2011. Included in this TY 2014 forecast are two additional power plant technicians at Humboldt Bay Generating Station

[1557] Ex. 79 (DRA-11), p. 79 [Source: 2007-2011 and 2014 data from Ex. 24 (PG&E-6), Chapter 4, Workpapers p. WP 4-1. The 2012 data is from PG&E's response to DRA data request DRA-PG&E-108-CKT.]

(HBGS) and work that was transferred from other MWCs. PG&E claims that additional power plant technicians are needed to back-up existing power plant technicians when they go on vacation.

> In order for PPT to be able to take his or her vacation time and any necessary sick leave, a PPT from one of the other three groups must work overtime to replace the vacationing or sick PPT in order to keep the required minimum plant operations staffing at two. This situation has created significant overtime and work/life balance issues.

(Ex. 30 (PG&E-7), p. 4-4 and 4-36.)

This argument for additional power plant technicians is not convincing. PG&E would have to have only two power plant technicians at each of its three new generating stations for the situation in this argument to arise, because if there are three or more power plant technicians at any of the other power plants, then PG&E can manage its power plant technician vacations in such a way to eliminate or minimize the concern it complains of here without costing ratepayers additional charges. Secondly, it is not clear where PG&E got the minimum power plant technician number from or whether PG&E set that number itself, but PG&E's power plants are among the newest power plants built in California since the electricity crisis. PG&E describes them as state of the art machines. It is difficult to understand why the must have two power plant technicians on site at any one point.

DRA further notes that:

> Despite its concerns about overtime, PG&E has embedded funding for "significant overtime" and associated employee expenses that can be reallocated and utilized in the Test Year for the requested positions.

(Ex. 79, DRA-11, p.82.)

Therefore, DRA opposes additional ratepayer funding for two additional power plant technicians because PG&E has not provided sufficient justification two additional power technicians at HBGS and PG&E's forecast for these two potential technicians is overstated anyway because it includes costs for materials, contracts, vehicles, etc. that should be accounted in PG&E's Administration and General expenses .

DRA also opposes PG&E's proposal to implement a document storage program to address PG&E's fossil generation document management and recordkeeping deficiencies. PG&E claims that "[t]he Independent Review Panel [IRP] report on San Bruno explosion

concluded that PG&E lacks robust data and documentation information management systems and processes …" This argument is misleading. The IRP did not state that PG&E should escalate its O&M costs above historical embedded costs to improve deficient record keeping and implement completely new record management systems when PG&E has been sufficiently funded over the years to have a better record system than it now professes.

As DRA's Report noted:

> "PG&E's records for its newly commission Fossil facilities should currently be accurate, complete, organized and accessible. If any of these new facilities are experiencing problems with record completeness, accuracy, availability and accessibility, PG&E needs to reallocate historical embedded costs to address [it.]."

Therefore, DRA recommends $12.935 million based on a two-year average of recorded expenses (2011 and 2012).

6.4.1.2 MWC KL – Maintain Fossil Generating Equipment

PG&E forecasts $31.942 million for its MWC KL TY 2014 expenses, an increase of $4.897 million or 18.11% over MWC KL 2011 recorded adjusted expenses of $27.045 million. PG&E claims that the increase in MWC KL expenses over 2011 recorded adjusted costs is due to implementation of a piping integrity program, implementation assessment program, implementation of a material traceability program and major engine prevention maintenance at the Humboldt Generating Station.

> DRA opposes PG&E's request for additional ratepayer funding for its Piping Integrity Program with a forecast of $0.722 million ($2.166 million over three years), its Machinery Assessment Program with a forecast of $0.386 million ($1.158 million over three years) and its Material Traceability Program with a forecast of $0.771 million ($2.313 million over three years). Regarding PG&E's Piping Integrity Program[1558] and its Machinery Assessment Program,[1559] the proposed activities are very similar to

[1558] The proposed activities for PG&E's Piping Integrity program for Gateway and Colusa Generating Stations include the measurement and tracking of hot and cold pipe hanger settings, inspection of operating records for temperature transients, non-destructive examination of critical welds and supports, detection of flow accelerated corrosion, review and inspection of steam trap and drain systems to ensure proper operation, etc. (Ex. 24 (PG&E-6 workpapers), p. WP 4-25).

[1559] The proposed activities for PG&E's Machinery Assessment Program include Installation of predictive diagnostic software and ongoing services that would potentially help to avoid unplanned equipment failure. This program is supposed to detect problems before they grow large and catastrophic to help the

> the work already covered under PG&E's Long-Term Service Agreements (LTSAs), which PG&E states is a "significant portion" of PG&E's O&M costs, which are funded by ratepayers. PG&E states "LTSAs provide an effective cost control measure for the major planned and unplanned maintenance activities" and that LTSA "are commonly used in the industry as a way to provide high reliability and efficiency for combined cycle power plants". The LTSA cover all inspections, maintenance, replacements and repairs due to wear and tear over the term of the LTSA.[1560]

(Ex. 79, DRA-11, pp. 83-84.)

It is rather curious that a state of the art power plant with a 20 to 30 year life that was completed in September 2010 should start in 2012 to insure ratepayer charges over historical costs for plant maintenance for preventive work that is not covered in the LTSA. "PG&E has not provided any documentation demonstrating that its current funding levels were insufficient to address its proposed activities. It is inappropriate to charge ratepayers excessive maintenance costs (double charging) for the same or similar maintenance activities that have costs embedded in historical expenses."[1561]

DRA takes the following position regarding PG&E's LTSAs:

> The maintenance cost of PG&E's combustion turbine (CT) and steam turbine (ST) generators is a large portion of PG&E's O&M expenses recorded in MWC KL. PG&E entered into Long-Term Service Agreements (LTSA) with General Electric (GE) to provide maintenance, inspections, replacements and repairs of its CT and ST generators at Gateway and Colusa Generating Stations. PG&E's 2014 forecast for the LTSAs are based on recorded costs in 2011. The LTSAs include variable (quarterly) and periodic milestone payments (hot gas path milestone or major inspection milestone payment).
>
> PG&E's next milestone payment for Gateway Generating Station is due in 2016 for the first major inspection. PG&E proposes to continue with the method adopted in the 2011 GRC and spread out or normalize the hot gas path milestone payments over the years 2014-2016. There is a forecasted Major Inspection Use tax that is also due at the same time and PG&E proposes to normalize this

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facility to initiate a more proactive maintenance process, etc. (Ex. 24 (PG&E-6), p. WP 4-26).

[1560] Ex. 24 (PG&E-6), p. 4-39.

[1561] Ex. 79 (DRA-11), p. 84.

> payment over the same time period, 2014-2016. PG&E's workpapers show the milestone payment on line eight and the forecasted Major Inspection Use tax payment on line nine for Gateway. The combined normalized annual payment for 2014-2016 is found on line one.
>
> The next milestone payment for a major inspection for Colusa Generating Station is due in 2019. PG&E proposes to normalize this payment over the years 2014-2019 (six years) along with the scheduled Major Inspection Use tax payment. PG&E also requests that it be authorized to adjust on a prospective basis the schedule for amortization of milestone payments so that PG&E can true-up its recovery of milestone payments in the next GRC. PG&E's workpapers show the milestone payment on line thirty-one and the forecasted Major Use tax on line thirty-two for Colusa. The combined normalized annual payment for 2014-2019 is found on line twenty-four.
>
> DRA does not oppose PG&E's proposal to continue to normalize the Gateway Generating Station milestone payment for the first major inspection and the Major Inspection Use tax payment due in 2016 over the period 2014-2016. However, DRA opposes PG&E's proposal to include in its 2014 GRC the normalized milestone payment for the major inspection and Major Inspection Use tax payment due for its Colusa Generating Station in 2019 over the period of 2014-2019 (six years). PG&E's Colusa Generating Station milestone payment and Major Inspection Use tax payment are due in 2019 which is during PG&E's next GRC and should be addressed at that time. DRA also opposes PG&E's proposal to prospectively adjust the amortization schedule for milestone payments since PG&E should retain the risk of cost recovery until the next GRC.

(Ex. 79, DRA-11, pp.86-88.)

Therefore DRA recommends $27.045 million for MWC KL using PG&E's 2011 recorded adjusted expenses as a basis.

6.4.1.3 MWC KM – Maintain Fossil Buildings, Grounds, and Infrastructure

PG&E forecasts $3.048 million or 50 percent above 2011 recorded costs of $2.015 million for its TY 2014 MWC KM expense. PG&E claims that these costs are primarily contract costs and for performing corrosion preventive work at HBGS. It is difficult to understand why the cost of maintaining the same piece of real estate would increase by 50 percent over a couple of years under normal wear and tear. PG&E must realize that a building's

exposure to weather is a normal event that should be planned in the normal course of maintenance not budgeted instantaneously to create an embedded cost that ratepayers would never again adjust even when the activity that escalated the cost has been completed.

DRA recommends $2.247 million for MWC KM using a two year average of recorded costs (2011 and 2012) as the basis for the forecast. DRA's recommendation is still $0.232 million more than 2011 recorded adjusted expenses and should be sufficient for maintaining facilities that only went into operation in the last two or three years.

6.4.1.4 MWC KQ – Operate Alternative Generation and KS – Maintain Alternative Generation Buildings, Grounds, and Infrastructure.

DRA forecasts $60,000 for MWC KS based on the following reasoning in its report:

> PG&E forecasts $0.364 million for its MWC KQ – Operate Alternative Generation expenses and forecasts $0.108 million MWC KS – Maintain Alternative Generation Buildings, Grounds, and Infrastructure expenses. PG&E based its TY 2014 forecast for MWC KQ and KS on "the forecasts used to develop the revenue requirement used in the CPUC decisions that approved these projects".[1562] DRA forecasts $60,000 for MWC KQ which is $0.304 million less than PG&E's forecast. DRA forecasts $6,000 for MWC KS which is $0.102 million less than PG&E's forecast. DRA utilized PG&E's 2012 recorded adjusted expenses as a basis for its Test Year estimates.[1563]
>
> PG&E does not show any historical expenses recorded for 2007-2011 for MWC KQ and KS. PG&E's alternative generation facilities were in operation for 2011[1564] and the entire year of 2012. PG&E states "Since PG&E does not have any significant experience with fuel cells, PG&E's O&M expense forecast in this

[1562] Ex. 24 (PG&E-6), p. 4-37. PG&E based its forecast for Vaca Dixon Solar Station (VDSS) on the revenue requirement used in D.10-04-052. The forecasts for San Francisco State and CSU East Bay fuel cell facilities were based on the revenue requirement used in D.10-04-028 (includes reduction for shared labor and reductions in the cost of the Long-Term Service Agreement (LTSA). PG&E is currently using the same employee to support its fuel cell facilities and its VDSS. The labor forecasts used for the revenue requirement adopted in D.10-04-028 was based on one full time employee dedicated to only supporting the fuel cell facilities (DRA-PG&E-088-TLG Q.4-b&c).

[1563] 2012 data is from PG&E's response to DRA data request DRA-PG&E-108-CKT.

[1564] PG&E's VDSS became commercial in December 2009, its fuel cell facilities entered commercial operations in September 2011. The solar technician that supports the fuel cells and VDSS facilities was hired in July 2011. (DRA-PG&E-088-TLG Q.4-a and Q. 5).

> proceeding is primarily based on the O&M expense forecast adopted by the Commission in D.10-04-028".[1565]

(Ex. 79, DRA-11, p.89.)

The rationale that where PG&E has insufficient proof to support its forecasts ratepayers should be prepared to pay more than historical recorded expense, turns the GRC process on its head. PG&E's fuel cells were in operation in 2011 and for the entire year of 2012, which gives PG&E sufficient data for developing historical costs. In any case, PG&E must have researched the operations and maintenance costs of these facilities before it incurred ratepayer funds to build them.

The Commission should adopt DRAs recommendation based on the recorded 2012 costs for MWC KQ.

6.4.2 Capital Expenditures

6.4.3 Decommissioning and Fuel Oil Inventory Costs

6.4.4 Costs for Fuel Cell Projects above Amounts Authorized in Decision 10-04-028

6.5 Energy Procurement Administration Costs

PG&E's Energy Procurement Administration plans, procures, schedules, dispatches and administers procurement agreements for the Company, ensuring that third-party power suppliers and the California Independent System Operator are paid for services related to the procurement and delivery of electricity and natural gas.

6.5.1 Expense

Table 11-28 of DRA's Report summarizes PG&E's request and DRA's recommendation for the MWCs in Energy Procurement Administration.

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[1565] Ex. 24 (PG&E-6), p. 4-23.

Table 11-29[1566]
Energy Supply Expenses for TY2014
Energy Procurement Administration
(In Thousands of Dollars)

Description (a)	PG&E Proposed[1567] (b)	DRA Recommended (c)
AB- Support	$2,630	$2,630
CT- Acquire and Manage Electric Supply	$50,209	$42,901
CV –Acquire and Manage Gas Supply	$5,961	$3,797
JV- Maintain IT Applications and Infrastructure	$3,000	$1,278
Less		
JV- Maintain IT Applications and Infrastructure	(3,000)	
Total	$58,800	$50,606

PG&E forecasts $58.800 million for TY 2014 Energy Procurement Administration expenses, an increase of $9.607 million or 19.53 percent over 2011 expenses of $49.193 million. According to PG&E, the drivers for the increase in costs over 2011 recorded adjusted costs, include a one-time labor adjustment, plus incremental expenses for proposed staffing and escalation[1568].

DRA recommends $50.606 million for Energy Procurement Administration. There are three MWC in Energy Procurement Administration: MWC AB – Administration Support with a forecast of $2.630 million, CT – Acquire and Manage Electric Supply with a forecast of $50.209 million, CV – Acquire and Manage Gas Supply with a forecast of $5.961 million, and JV - Maintenance of Information Technology Applications with a forecast of $3.0 million.[1569] DRA has no objection to MWC AB but made adjustments to the remaining three MWCs as follows.

[1566] Ex. 79 (DRA-11), p. 90.

[1567] Ex. 24 (PG&E-6), p. WP 5-1.

[1568] Ex. 24 (PG&E-6), pp. 5-46 and 5-47.

[1569] Ex. 24 (PG&E-6 workpapers), p. WP 5-1.

6.5.1.1 MWC CT – Acquire and Manage Electric Supply

PG&E forecasts $50.209 million for TY 2014 expenses to acquire and manage Electric Supply. This amount is an increase of $7.308 million or 17. 03 percent over PG&E's 2011 recorded adjusted expenses of $42.901 million. The primary driver for the increase in TY 2014 MWC CT expenses over 2011 recorded adjusted expenses is PG&E's claimed need for additional staffing.

Staffing level was at 291 positions in 2011, but PG&E feels that level is insufficient going forward and would like to add 37 additional position in TY 2014 to address compliance mandates, internal initiatives, process improvements and cost escalation.[1570] PG&E has not presented any evidence in this proceeding to show how it determined that it would need 37 additional positions in Energy Procurement to support the acquisition and management of Electric Supply.

PG&E states that "[t]he work performed by the Energy Procurement Organization has been steadily growing in volume and complexity, requiring additional employees to handle this increased workload."[1571] DRA found that Energy Procurement Administration had 291 positions in 2011 and 292 positions in 2012. A "steady' progression of this metric belies PG&E's claim that it needs 37 new positions in TY 2014. Even considering the fact that PG&E hired 89 employees in Energy Procurement Administration between 2007 and 2011-cannot justify 37 new positions in 2014. PG&E has not provided any evidence to show what increased workload the Energy Procurement employees have to contend with in the TY, except to list existing regulations. For instance, California's Renewable Procurement Standard (RPS) program required utilities to procure 20 percent of their retail sales of electricity from renewable resources by 2010 and the mechanics for implementing that process intensified between 2007 and 2010, with the Commission considering decisions on whether the State would adopt tradable renewable certificates (T-RECs) or not, how the utilities can firm up alternative resources purchased in other states, flexible compliance mechanisms, among others. While this may have been used to support an increase in procurement positions between 2007 and 2010 all these situations have now been resolved for the most part and employees whose responsibility it was to address these

[1570] Ex. 24 (PG&E-6), p. WP V1, p. 5-1; Ex. 79 (DRA-11), p.92.

[1571] Ex. 24 (PG&E-6), p. 5-4.

issues should be available to take on new responsibilities. The next RPS compliance target is 2033 but the modalities for complying with that law have all been established.

DRA is also concerned that in 2011 PG&E requested $89.060 million for its MWC CT. After the 2011 GRC was settled, PG&E budgeted $54.06 million for MWC CT, but 2011 recorded cost is only $43.9 million, $11.156 million less that PG&E budgeted for the purpose[1572].

> PG&E has embedded historical funding that it was authorized in its 2011 GRC that it can reallocate and utilize for its proposed activities in MWC CT. It would be inappropriate to charge ratepayers twice to address these activities that have costs embedded in historical expenses. As discussed below, PG&E overstated its 2012 forecast.

(Ex. 79, DRA-11, p.94.)

DRA recommends $42.9 million for MWC CT TY 2014 expense using 2011 recorded adjusted expense level as a basis for its forecast. PG&E is using the same regulatory proceedings and rationales it used to justify its request for MWC CT funds in TY 2011 to justify its TY 2014 forecast.[1573].

6.5.1.2 MWC CV – Acquire and Manage Gas Supply

PG&E forecasts $5.961 million for MWC CV TY 2014 expenses, an increase of $2.164 million or 56.99% over its 2011 recorded adjusted expenses of $3.797 million. PG&E's claims the additional funding is for inflation and "new resources necessary for AB 32 implementation", and for additional staffing positions to address compliance mandates, internal initiatives, process improvements, and cost escalation. PG&E's request for additional funding for its MWC CV is excessive and not supported by the record in this proceeding. In fact, DRA is informed and believes that PG&E and other utilities were authorized a balancing account for AB 32 costs and were to continue to recover those costs through that mechanism until further notice.

DRA forecast of $3.797 million for MWC CV - Acquire and Manage Gas Supply expenses.

> PG&E's expenses for MWC CV- Acquire and Manage Gas Supply, have been relatively stable for the last three years (2010-

[1572] Ex. 79 (DRA-11), p. 94.

[1573] Id., pp. 93,96,97

> 2012) with an average for the three year period of $3.795 million. PG&E's expenses fluctuated slightly between 2007 and 2010 with an average for the four year period (2007-2010) of $3.522 million. There was a small increase between 2009 and 2010 of $0.291 million, as mentioned above in the discussion for MWC CT-Acquire and Manage Electric Supply expenses, the increase may have also been associated with labor costs for additional staffing as PG&E prepared for implementation of compliance mandates (i.e., 33 percent Renewable Portfolio Standard (RPS), Assembly Bill (AB) 32 Greenhouse Gas (GHG) Cap-and-Trade implementation, Qualifying Facility/Combined Heat and Power (QF/CHP) Settlement and the Dodd-Frank Wall Street Reform Consumer Protection Act). PG&E hired 89 additional employees between 2007 and 2011 for its Energy Procurement organization to meet its compliance mandates and this staffing level should be sufficient for PG&E to perform its proposed Test Year activities.

(Ex. 79, DRA-11, pp.98-99.)

6.5.1.3 MWC JV– Maintain IT Applications and Infrastructure

PG&E forecasts $3.0 million for its TY 2014 MWC JV expenses, an increase of $2.094 million or 231.13% over its 2011 recorded adjusted expenses of $0.906 million.

> PG&E's request for additional funding is for "developing and implementing new software or systems" (i.e., projects for Forecasting, Central Data Repository, Document Management, Settlement Quality Meter Data (SQMD), Replacement, Reporting Expansion/Systems/Software Upgrade, CAISO MAP. PG&E's request for additional funding for its MWC JV is excessive and not justified when compared to historical levels.

(Ex. 79, DRA-11, p.100)

DRA recommends $1.278 million using a three-year average (2009-2011) as the basis for its Test Year. The fact that a Company the size of PG&E can remain inefficient by using time-consuming manual processes and multiple systems for record management reflects and inefficient use of past funding and unreasonable management for which ratepayers should not incur a surcharge. Therefore, DRA opposes additional ratepayer funding for PG&E's projects for its Central Data Repository ($1.5 million over three years) and Document Management ($1.2 million over three years) to address PG&E's Energy Procurement Administration's recordkeeping deficiencies.

DRA conducted substantial discovery in an attempt to better understand the need for PG&E's proposed Document Management project but PG&E was in parts non-response and mostly evasive as follows:

Regarding documentation to support the fact that Energy Procurement has not received funding in this past for this document management activity, PG&E's response was:

> GRC settlement agreements do not provide specific values for MWCs. Please refer to GRC2014-Phl_DRA_093-Q01 for additional information.

(Ex. 79, DRA-11, p.102.)

Regarding how long PG&E had been aware that "Various regulatory authorities require evidence of operational compliance through documentation" from PG&E's Energy Procurement Administration, PG&E responded:

> PG&E has always been aware of the need to maintain documentation that supports evidence of regulatory compliance. Energy Procurement continues to evaluate solutions that will ensure proper and efficient document management practices, especially as energy markets and regulations continue to evolve.

(Id., p.102)

Regarding the documentation with which to verify the need for such compliance, PG&E responded:

> While no fines or penalties have been levied due to PG&E's inability to "timely or completely access documentation," PG&E is facing additional compliance requirements in increasingly complex energy markets since its last GRC filing. These factors have escalated the need for more centrally managed documentation. Please refer to Chapter 5 of the testimony (pages 5-7, and 5-29) for additional information on new compliance requirements and market initiatives.

(Id.)

And on why PG&E failed to use its authorized funding for this compliance in the past, PG&E responded:

> GRC Settlement agreements do not provide specific values for MWCs. Please refer to GRC2014-Phl_DRA_093-Q01 for additional information.

(Id., p.103)

DRA also asked about the number of years PG&E was aware, prior to this rate case, that its Energy Procurement Administration's Legacy, home-grown systems relied upon for reports lacked 'complete, timely or accurate data requiring highly manual validation procedures'.

PG&E's response:

> Energy Procurement does not have specific documentation regarding the number of years it was aware that its legacy, home grown systems lacked complete, timely or accurate data, and required highly manual validation procedures. However, in 2011, Energy Procurement completed an assessment of its regulatory reporting processes and systems, which concluded that the current legacy processes and systems capabilities were strained, mainly due to PG&E's growing energy portfolio, new market initiatives and regulation. This was further underscored with the 2012 release of the Five Year IT Roadmap, prepared by an outside consultant, which highlighted principal information system shortcomings and recommended enhancements.
>
> Energy Procurement does not have specific documentation regarding the number of years it was aware that its reliance on data from applications external to Energy Procurement results in inefficient and highly manual methods of report preparation and the increased likelihood of error. However, in 2011, Energy Procurement completed an assessment of its regulatory reporting processes and systems, which concluded that the current frequency and breadth of required data was manually and automatically extracted from numerous and disparate sources – internal and external to PG&E. This was further underscored with the 2012 release of the Five Year IT Roadmap, prepared by an outside consultant, which highlighted principal information system shortcomings and recommended enhancements.
>
> (Id., p. 104.)

PG&E's responses are insufficient and incomplete and do not justify additional ratepayer funding for these projects.

6.5.2 Capital Expenditures

6.6 Energy Supply Ratemaking

DRA incorporates the ratemaking analysis from it Energy Supply O&M Expense Report herein, without change.

6.6.1.1 PG&E's Proposal to Credit its Electric Generation Revenue Requirement with Funds Received from DOE

PG&E proposes to credit (net of litigation costs) the electric generation revenue requirement with funds it receives from DOE as a result of its September 5, 2012 settlement in the DOE litigation. The proposed credits are the result of PG&E's litigation regarding the failure of the DOE to take and permanently store spent nuclear fuel from PG&E's nuclear facilities. PG&E's proposal includes amortizing the litigation settlement proceeds over the three year rate case cycle which is forecasted to result in a reduction to generation rates of $340 million over the three year period.

Based on the settlement agreement, PG&E was supposed to receive, in the fourth quarter of 2012, $266,104,245 for spent fuel storage costs and other reimbursable damages incurred through the end of 2010. PG&E will continue to receive payments annually for three years. PG&E states "any additional funds received in 2014 through 2016, currently estimated at about $20 million per year annually, will be credited to rates on an actual basis".

DRA does not oppose PG&E's Test Year proposal as stated in the November 15, 2012 testimony to credit (net of litigation costs) the electric generation revenue requirement with funds it receives from DOE. However, due to uncertainty surrounding the allocation of DOE credit to PG&E customers, DRA does not express an opinion in this report regarding DOE credit allocation.

PG&E's April 8, 2013, Notice of Ex Parte Communication with Administrative Law Judge Thomas Pulsifer states, "…PG&E explained that it is modifying its proposal concerning the proceeds from Department of Energy litigation. PG&E's original proposal was to credit 100% of the proceeds to the Utility Generation Balancing Account (UGBA). PG&E's modified proposal is to credit the portion of the proceeds relating to the Humboldt Bay facility to the Nuclear Decommissioning Adjustment Mechanism (NDAM) thereby reducing the NDAM rate." In light of this, DRA reserves judgment on the appropriate policy for how DOE refunds should be returned to ratepayers, given that PG&E appears to have changed its proposal.

6.6.1.2 PG&E's Proposal to Credit Back Customers Savings Associated with its Photovoltaic Program

PG&E proposes to "credit to generation rates the difference between the revenues assumed in the PV decision and the revenues based on the actual PV capital costs for the first 150 MW of the PV Program over the 3-year GRC period." PG&E proposes to credit back to

customers the savings associated with the first three years of its Photovoltaic (PV) Program due to the actual capital costs of the first two 50 megawatt tranches of the PV being lower than authorized in Decision 10-04-052. PG&E's generation revenues are forecast to be reduced by approximately $90 million over the GRC period as a result of this credit. PG&E states to "minimize any excess revenue collection from 2014 onward", it proposes to prospectively adjust the revenue requirement for the PV program.

DRA does not oppose PG&E's proposal to credit back to customers the savings associated with the first three years of its PV Program due to the actual capital costs of the first two 50 megawatt tranches of the PV being lower than authorized in Decision 10-04-052. DRA does not express an opinion in this report regarding the credit allocation to customers.

6.6.2 Balancing Account

PG&E proposes to establish two-way balancing accounts for FERC Hydro licensing and licensing implementation work under MWC 11 because of challenges with determining the nature and timing of the costs of implementing new license conditions and receiving new licenses from FERC.

PG&E describes the FERC licensing work under MWC 11 as follows:

> MWC 11includes the investments needed to obtain new long-term (30 to 50 years) FERC licenses for the existing hydro facilities upon expiration of the previous licenses; to amend the FERC licenses to reflect major changes in the license projects facilities and /or operations; and to install or construct new capital equipment or facilities to comply with the FERC existing or new license conditions.

(Ex. 24, PG&E-6, p.2-131.)

DRA opposes PG&E's proposal for a balancing accounts for the following reasons:

> PG&E proposes that $28.6 million of the MWC 11 capital budget of $45.2 million receive two-balancing account treatment for ratemaking purposes. PG&E also proposes that Hydro Relicensing expenses be subject to two-way balancing account treatment; this is addressed in Exhibit DRA-11 (Energy Supply Expenses). PG&E bases its proposal on the fact the hydro relicensing activities are subject to greater uncertainty due to federal regulatory schedules, lengthy stakeholder processes and incongruity with the three-year general rate case cycle.
>
> For the purposes of capital budgeting, a two-way balancing account does not appear to provide any real benefits to ratepayers.

> First, the historical recorded costs have not been treated with the balancing account, so there is no way to capture any over-collection ratepayers could have due in this general rate case cycle. Second, any differences between actual and adopted costs for ratemaking purposes will be trued up in the generation balancing account. Finally, two-way balancing treatment tends to favor inflated forecasting when it is known that unspent funds will be returned to ratepayers. It would not be a good policy for ratepayers to provide this "safety cushion" for the utility's capital budget. For all of these reasons, DRA recommends that the two-way balancing account proposal not be adopted for the hydro relicensing capital items.

(Ex. 80, DRA-12, pp. 12-13.)

Regarding the balancing account as it pertains to ES O&M FERC expenses, DRA's ES O&M Report stated:

> As discussed in DRA's testimony in this report on PG&E's Hydro Operations forecast for MWC KJ, DRA opposes PG&E's request to establish a two-way balancing account for pending FERC licenses and recommends that the Commission reject PG&E's request. This is not the first time PG&E became aware that it had to incur costs to renew or amend FERC licenses and possibly implement new FERC-mandated conditions.[1574] PG&E's historical expenses include embedded costs for these pending licenses.[1575] PG&E has received sufficient authorized funding to address past licensing renewal and amendment activities and establishing a two-way balancing account is not required.
>
> PG&E also has embedded costs that can be reallocated and utilized in the Test Year if incremental funding over DRA's Test Year estimate for MWC KJ is needed.

(Ex. 79, DRA-11, p.107.)

6.6.2.1 DOE Litigation Refund

DRA does not oppose PG&E's Novmeber 2012 proposal, but reserves judgment on the appropriate method for returning the refunds to ratepayers.

[1574] DRA-PG&E-101-TLG, Q.3-b.

[1575] DRA-PG&E-101-TLG, Q.3.

6.6.2.2 Credits Regarding PG&E's Utility-Owned Generation Photovoltaic Program

DRA has no comment on this issue at this time.

7 SHARED SERVICES AND INFORMATION TECHNOLOGY

Shared Services and Information Technology forecast estimates are costs that are common to all of PG&E's Lines of Business. These costs are grouped together because they benefit the Company as a whole, unlike those costs that benefit specific business units to the exclusion of others. Shared Services comprises of the following six groups or divisions:

1) Safety Department;
(2) Transportation Services;
(3) Supply Chain—Materials Logistics and Planning;
(4) Supply Chain – Sourcing Operations;
(5) Real Estate; and
(6) Environmental Program.

Information Technology (IT) provides IT services and maintains PG&E's IT assets throughout the utility's service territory with the following portfolio of services: (1) Baseline Operations Portfolio; (2) Technology Reliability Portfolio; and (3) Business Technology Project Portfolio. Where PG&E seeks to collect costs under Shared Services and IT that has also been requested under a specific line of business or business unit, even while the requested cost is a Shared Services cost, the Commission must reject those costs under Shared Services and IT. Such duplication should be considered suspect and strictly construed.

7.1 Policy and Introduction

One objective for grouping particular services and functions under Shared Services and IT is to realize some economies of scale. However, this objective is completely lost when year after year Shared Services and IT find ways to arbitrarily increase costs that usurp any realized savings from the desired economies of scales.

7.1.1 PG&E's Position On Historical Expense

PG&E criticized DRA's use of recorded historical data to support recommendation for Shared Services and IT. This criticism remained a refrain throughout PG&E's rebuttal to all DRA testimony. For Shared Services MWC FL, PG&E stated the refrain as follows:

Q. 5. DRA generally criticizes PG&E's showing on the ground that historical expense and capital cost can be exclusively relied upon to establish future forecasts. What is PG&E's reaction to DRA's position?

Q. 6. DRA's position is inappropriate. Historical expense and capital cost do not reflect the new initiatives the Safety Department is undertaking nor do they reflect the restructuring of PG&E's Safety Department described in this General Rate Case (GRC). These programs support improved employee, contractor and public safety[1576].

PG&E's argument that historical data does not reflect new initiatives is semantic chicanery and somewhat hypocritical given that much of what PG&E has provided to support its Safety Department recommendations was based on a review of its historical activities or arbitrary correlations between its narrative descriptions and risk. Witness after witness admitted that PG&E has never done a cost benefit analysis nor conducted any studies to correlate its claim for additional funds with the purported new initiatives. PG&E would like the Commission to believe that every new initiative it proposes in this GRC must be supported with a funding increase over prior years GRC expense. Such a conclusion is arbitrary because it presupposes that existing employees' time was insufficient to support such new initiatives without explaining why or providing any report to support the conclusion. Moreover, it is difficult to understand why much of the new initiatives are not replacing existing initiatives, and therefore freeing existing employees to take on new responsibilities, when much of the justification for the new initiatives is that existing programs are not working. Consider the following explanation for a Safety Audit/Assessment Program:

> The Safety Department will perform periodic safety audits/assessments to determine the level of employee compliance with safety rules and regulations and to determine if corrective actions are needed. A review of the serious incidents experience over the past few years indicates that an employee's failure to comply with established rules and procedures was a key contributing cause of many incidents. The Safety Department will use the information collected during the safety audits and assessments to identify opportunities for improvement. Ultimately the safety audit and assessment program will improve employees understanding of and compliance with, the safety rules regulations related to the work they perform.[1577]

[1576] Ex. 60 (PG&E-22), p. 2-2.

[1577] Ex. 30 (PG&E-7), p. 2-12.

Notwithstanding these arguments, it is far too simplistic to claim that DRA relied solely on historical expense data to make its recommendations. As the foregoing discussion has shown, DRA addressed every single argument PG&E put forward to support its need for new funds and found that they were merely pretexts for obtaining funding far and above the historical increases that PG&E has always found sufficient to serve its ratepayers.

In D. 11-05-018, which approved PG&E's 2011 Phase I GRC, the Commission directed PG&E to provide periodic compliances filings showing authorized and recorded expenses and capital expenditures by major work categories for electric distribution, generation and gas distribution. DRA reviewed all of PG&E's applications and testimonies, work-papers and recorded adjusted expenses and conducted further discovery. Based this analysis, DRA recommends that the Commission only approve $296.3 million for Shared Services and IT.

7.1.2 Shared Services

PG&E's 2014 forecast expense for Shared Services is $103.2 Million. DRA reviewed PG&E's rationales for the 2014 Shared Services forecast estimates, testimonies, and work-papers and conducted discovery to understand why PG&E's 2014 forecast is about two times more than the 2011 recorded adjusted expenses for the same group of services. In 2011, PG&E's recorded adjusted expense for Shared Services was $54.6 million. For 2014, PG&E has included several new programs or other "enhancements" and "optimizations" of existing projects that PG&E claims would improve services, but a closer review of these programs shows that they do not provide any ratepayer benefits or savings. PG&E's has not bothered to explain why a program or function that is working well enough should be tinkered with at a huge costs to ratepayers, with no documented savings or particularized showing of need by the Company.

PG&E also claims that a substantial part of the cost for shared services is for compliance with Americans with Disability Act, but the ADA has been in existence since 1992. Why PG&E must now revamp its entire real estate assets as though they have never been in compliance with this law in the past is highly questionable.

DRA recommends that the Commission approve the sum of $64.5 million for Shared Services, which is still an increase of $9.9 million over 2011 recorded adjusted expenses.

7.1.3 Information Technology

PG&E's IT forecast expense for 2014 is $261.6 million while recorded adjusted expense for 2011 was $217 million. IT costs include operations and maintenance costs for company-

wide technology projects and systems, as well as new capital projects. PG&E claims that its IT O&M forecast increased as a result of contracts and licenses it acquired to support growth in assets and services and also due to increased headcount in IT to support the growing number of applications and systems that various lines of businesses are deploying. The main capital drivers include upgrading and maintaining PG&E's IT asset base, three initiatives focused on improving cyber-security, and two initiatives focused on continuous improvement.

Within Shared Services divisions and IT portfolios, the various services that make up PG&E's forecast for this category of expenses are further grouped into major work categories (MWC). The three MWCs for Shared Services and IT are: (1) MWC FL—Safety, (2) MWC JV – Maintain IT Applications and Infrastructure and (3) MWC 2F – Build IT Applications and Infrastructure.

The analysis that follows reviews each MWC and their respective cost estimates, first for Shared Services and then for IT.

7.2 Safety Department

PG&E's Safety Department is responsible for the management and control of several health and safety programs that protect the wellbeing of PG&E's employees and the public. The Department also ensures Company-wide compliance with various safety laws and requirements such as the Occupational Safety and Health Administration (OSHA) rules and Motor Vehicle Safety.

7.2.1 Expense

MWC FL is the Safety Department's only major work category. It forecasts costs the Safety Department claims it needs to establish and implement the overall framework for PG&E's safety policies and applicable regulations for test year 2014.

7.2.1.1 MWC FL [PG&E - $15.6 Million; DRA $12.9 Million]

PG&E's test year 2014 forecast for MWC FL is $15.6 million. PG&E claims its forecast needs for MWC FL was based on its evaluation of the 2011 adjusted recorded expenses and the costs for new programs, materials and supplies, Enterprise Content Management and additional staffing needs. However, the main driver for the forecasted increase in MWC FL is the claimed need for twenty-one new full-time equivalent positions for 2014.

Upon review of PG&E's work-papers and discovery, DRA found that MWC FL still had seven vacant positions from 2011. PG&E's testimony had in fact counted these positions as active filled position until DRA sent a data request seeking clarification of the numbers claimed by PG&E for the Safety Division.

> Q. [Ms. Tudisco for DRA][1578]
>
> On page 2-6 in your testimony in connection with the—well, it starts on page, yes, 2-6, goes over to page 2-7, and it has to do with Safety Department 7 vacant positions and PG&E's claim that it needs 21 additional safety professionals. There was a data request response that DRA sent to PG&E about this, these additional safety employees; is that right?
>
> A. [Ms. Lindberg for PG&E] Yes.
>
> Q. And that has been marked as Exhibit 254. Do you have that in front of you?
>
> A. I do.
>
> Q. And if you look at the data request response, is this information that PG&E provided to DRA?
>
> A. Yes, it is.
>
> Q. So at the last paragraph of the first page of this data response it refers to PG&E's testimony, from the direct testimony, that it had 74 employees at the end of 2011. And it gives the cite where that appears in PG&E's direct testimony. Do you see that?
>
> A. Yes.
>
> Q. So at some point in 2011 did PG&E actually have 74 employees in its safety department?
>
> A. I'm not positive about that. What I do know about the 74 figure is that at the end of 2011[,] 7 of those positions were vacant. So they had 67 active employees.[1579]

The twenty-one new staffing positions for MWC FL are in addition to the seven positions that had not yet been filled since 2011. The costs for these vacant positions remain embedded in Safety Division's historical costs, even if the funds approved for the positions in 2011 were used for other purposes. Thus by 2014, Ratepayers would have paid for seven vacant positions in two

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[1578] Tr. Vol. 23, p. 2815-2816.

[1579] Id.

rate cycles which is akin to paying for fourteen new positions in one rate cycle. This alone reflects that PG&E's claim that it needs twenty-one new staffing positions for MWC FL is exaggerated. How can PG&E know the right number of employees it needs for MWC FL when it starts off the calculation with a number that is decidedly false? It is interested to note that a Mr. Hughes wrote PG&E's opening testimony, which stated the wrong number of active employees, but being absent at the time the rebuttal was prepared and during hearings, Ms. Lindberg stepped in for Mr. Hughes. When asked whether PG&E actually had 74 active employees in its Safety Department "at some point in 2011", Ms. Lindberg's response was "I'm not positive about that …" PG&E has the burden of proof in every rate case proceeding[i]. In order to support the burden of proof for adding 21 new staffing positions in the Safety Department, PG&E should at the very least present testimony that is more reliable as to how many employees are actually in the Department at any point in time.

DRA recommends that the Commission approve $12.9 million for MWC FL. DRA determined its estimate of $12.9 million by reviewing PG&E's historical data from 2007 through 2012 and taking a five-year average of the recorded costs for those years. Further, DRA reviewed the ratio PG&E's active employees in the Safety Department to the number of PG&E's International Brotherhood of Electric Workers (IBEW) employees over the same five years. The record showed that the ratio did not change in those five years, but the addition of 21 new staffing positions would be completely at odds with that ratio.

PG&E claims that DRA's analysis of the ratio of employees to the number of IBEW employees at PG&E is flawed[1580] "since IBEW employees only reflect a sub-set of the total PG&E employee population."[15811582] PG&E would rather benchmark the ratio of safety employees to the total population of Company employees. However, by PG&E's rationale, the number of secretaries at PG&E who only work at stations operating computers and phones would determine how many Safety Department employees are needed at the Company by the same ratio as line-men and other field employees who do more dangerous work. Furthermore, the fact that the ratio of Safety Department employees to total company employees has remained

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[1580] Ex. 60 (PG&E-22), p. 2-7.

[1581] Id.

[1582] Which figure was later corrected to 67. (Tr. Vol. 23, 2816.)

relatively unchanged over the five years of recorded historical data, shows that, contrary to PG&E's objection, there is a rational relationship between the two numbers that makes the comparison to IBEW employees a better comparable than total company employees.

PG&E's primary justification for these positions also supports DRA's use of the ratio of safety employees to IBEW workers.

> Enhance Field Safety
> Effectively managing safety related risk and moving towards an injury and illness free environment, requires a strong operational safety team that is working closely with employees performing the work in the field. The Safety Department had 74 employees at the end of 2011 but requires additional employees to provide an adequate level of support for field operations. The Enhance Field Safety initiative will add resources to the operational safety teams and will also provide teams with the technology necessary to perform their work more effectively. It is made up of two key components.
>
> - The Safety Department will add 18 positions to the Operational Safety team over a three-year period (2012 to 2014). These additional employees will be primarily focused on providing more safety support for Electric Operations, Gas Operations, Energy Supply and Customer Care field employees. The additional employees will allow the Operational Safety team to spend the time necessary at worksites while reducing the amount of time spend in their vehicles driving from site to site[1583]

This testimony shows that the key driver for the addition of new safety employees is the number of IBEW employees at PG&E not the total population. In any case, the fact that PG&E is using the total number of company employees to justify new staffing positions for its Safety Department, shows that PG&E has no reliable metric for determining the reasonable number of employees it needs to support future projects. As Liberty Consultants noted, even PG&E's concept of safety is nebulous. Until PG&E has a rational metric for determining the number of employees it needs in the future, the Commission should continue to rely on recorded historical evidence to support the additions. DRA's recommendation of $12.9 million for MWC FL is sufficient to support the Safety Department's enhancement of field safety and its implementation of the overall framework for the Company's safety policies and applicable regulations for test year 2014.

[1583] Ex. 30 (PG&E-7), p. 2-11.

7.2.2 Capital Expenditures

7.3 Transportation Services

PG&E's Transportation Services (TS) acquires, manages, maintains and repairs PG&E's fleet assets, including trucks, vehicles, off-road equipment, and trailers needed to provide service and operate the Company's electric and gas systems[1584]. TS also maintain PG&E's only aircraft which is principally used to serve the Diablo Canyon Power Plant (DCPP) operations[1585]. TS distributes all fleet-related expenses among all of PG&E's lines of business using "chargebacks" and these chargebacks are included in each line of business chapter and requested in those chapters but are discussed herein as part of Shared Services and IT[1586].

7.3.1 Expense

TS costs are forecasted for expenses and capital like all other Shared Services sections. PG&E forecasts $3.1 million for TS expense in 2014. PG&E acknowledges that "the last recorded expense for TS was $303,000 in 2010". Therefore, PG&E's current expense forecast for TS in 2014 is about a thousand percent larger than what PG&E needed for the same division only three years earlier. The fact that DRA did not find it necessary to respond to PG&E forecasts beyond test-year 2014 should not be viewed or construed as DRA's acceptance of, or acquiescence to, those costs in this or any other rate case in the future[1587]. DRA recommends that the Commission approve only $1.35 million for TS expense.

PG&E's forecast for TS capital expenditure through the five years from 2012 through 2016, as follows:

(1) $139. 4 million in 2012,

(2) $146.6 million in 2013,

(3) $139.3 million in 2014,

(4) $124.3 million in 2015,

(5) $122.2 million in 2016.

[1584] Ex. 86 (DRA-18, p.13); Ex. 30 (PG&E-7), p. 3-1.

[1585] Id.

[1586] Id., p.3-2

[1587] DRA urges the Commission to make this a Finding of Fact and part of the Order in any decision authorizing recovery for PG&E's test year 2014 rate case.

By contrast, DRA's makes the following recommendations for TS capital costs from 2012 through 2014 but makes no recommendations for 2015 and 2016[1588]:

(1) $174.172 million in 2012,

(2) $90.021 million in 2013,

(3) $103,613 million in 2014.

7.3.1.1 MWC JV – Maintain IT Applications and Infrastructure

PG&E records the $3.1 million forecast expense for TS as a Shared Services item under MWC JV. In addition, PG&E also has $49.1 million fuel expense that is not included in any separate MWC charged back to other lines of business in 2014. This fuel charge back is recorded in the Results of Operations for this GRC. DRA reduced the fuel expense to $35.1 million and records it under "Other Adjustments" in the Result of Operations tables[1589].

The $3.1 million TS forecast expenses is made up of the following forecast items: (1) $1.1 million forecast for Improved Transportation Compliance Management tracking and Reporting; (2) $1 million for Vehicle Safety and Operational Tracking and Reporting, (3) $670, 000 forecast for Fleet Management Application Optimization, (4) $250,000 for IT Infrastructure Optimization, and (5) $100,000 for Field Enablement of IT Systems in Garages.

DRA's $1.350 million recommendation for TS expense forecast removes PG&E's proposed Improved Transportation Compliance Management Tracking and Reporting and Fleet Management Application Optimization forecast costs from TS expense forecast. PG&E did not provide any information that measures the benefits of the Transportation Compliance Management Tracking and Reporting and Fleet Management Application Optimization initiatives or verifies that they necessarily improve TS functions in any manner that justifies their costs.

PG&E provides the following description for Transportation Compliance Management Tracking and Reporting:

[1588] In almost all TS forecasts, PG&E forecasted costs beyond test year 2014 without discussing why it has chosen to do so.

[1589] Ex. 86 (DRA-18), p. 16.

> To support the TS goal of improving compliance management, current paper records will be digitized and integrated with SAP and fleet systems for easy access by the DOT compliance group. This enhanced tracking and communications with field employees will improve communication and response time, thereby reducing compliance risk.[1590]

This description reflects much of PG&E's testimony in this proceeding, full of narrative without substance. It does not describe the compliance system that PG&E seeks to improve but only refers to it as a "current paper records" that need to be digitized. How were those paper records created? By computer intakes that are recorded on Excel or word applications and then printed out? Or by hand-written notes that are never stored on computer or scanned into a database? It is difficult to imagine that the DOT will not be able to produce a digitized record of all of PG&E's compliance records even if PG&E does not store them digitally. The notion that "current paper records will be digitized and integrated with SAP fleet" does not provide sufficient information for measuring how much such a process would cost, much less understanding why it is needed. Further, it is not clear what PG&E means by "current paper records". Are they 2011 paper records or do they include a back log of records that are currently kept in paper form? What kind of records are these? Are they all generated by PG&E? Are some of them generated by the public or auto manufacturers and service stations?

In a section on its proposed "consolidation of DOT Compliance Group" PG&E gives some glimpses into the kind of records that may comprise the "current paper records" it seeks to digitize under the Management Tracking and Reporting project.

> Transportation Services intends to create a single organization responsible for ensuring compliance with vehicle, driver, and pipeline related DOT, and California Highway Patrol (CHP) regulations. … The consolidation organization will:
>
> - Develop a process to review current procedures relative to regulatory requirements.
> - Develop standard operating procedures to ensure compliance with all DOT and CHP standards and regulations across the Company.
> - Develop a compliance review procedure (audit).
> - Perform an annual compliance review.

[1590] Ex. 30 (PG&E-7), p. 3-17.

> This initiative will allow PG&E to be more responsive to state and federal DOT and CHP regulations. The new DOT Compliance organization (within TS) will have the authority to hold departments accountable for following procedures and an adequate budget and staff to handle both centralized and field functions, including: drug testing, ensuring current status of medical cards, reducing lags in medical status reporting and the associated risk of deploying unqualified drivers, and centralized access to all relevant agency (DOT and CHP) regulations. TS plans to fund technology solutions that address data warehousing, timely field access to all driver status information, and data integration with core systems.[1591]

Essentially, PG&E will try to have the same records it has submitted to DOT and CHP, along with medical records and budget information available on a computer database at some location where these can be accessible to its DOT Compliance group. Clearly PG&E does not submit this information to the DOT and CHP in handwritten form that is not transcribed or scanned or already in a computer for ready data warehousing. PG&E has not indicated what activities it would need to engage in implementing these technology solutions that would cost $1.1 million. PG&E seeks to astound the Commission by suggesting that it is still operating key aspects of its operations that may affect public safety by shuffling papers, when PG&E should rather be held responsible for failing to digitize these aspects of its operations in line with other utilities despite receiving larger or similar funding that those other utilities over the years and paying out even greater dividends to its shareholders.

PG&E argues that the Improved Compliance Tracking and Reporting System would have prevented it from being fined $200,000 for lost hard copy records of vehicle opacity (diesel emissions) test certifications[1592].

> Q.41 What are the consequences of not implementing a Compliance Tracking And Reporting System?
>
> A.41 TS will continue within the constraints of its current tracking and reporting system which relies on manual records (hard copy). This is increasingly challenging due to business/fleet growth and the frequency and volume of updates required as one of California's largest commercial fleet operators. A case in point, in 2007, TS was fined $220,000 for lost hard copy records of vehicle opacity (diesel emissions) test certifications.

[1591] Ex. 86 (DRA-18), p. 3-14.

[1592] Ex. 30 (PG&E-7), p. 3-17.

> To avoid similar situations, TS has proposed these Compliance Tracking and Reporting System enhancements. This increased security and accessibility will dramatically reduce risk of future noncompliance penalties[1593].

PG&E provided no documentation or reference to support this incident or prove the fact that it resulted from the loss of a hard copy rather than actual non-compliance or other form of negligence. Nonetheless, the claim actually makes the case against spending additional funding on the purported improvement of the tracking system. The incident happened in 2007 and PG&E waited about five years before seeking to implement the process that would reduce further exposure to such costs. Either PG&E knows that the improved tracking system would not have made much difference in that regard or the existing system was sufficient to prevent such violations going forward as was evident from the fact that no such incident occurred again since 2007.

There is no evidence to support the notion that PG&E's Transportation Compliance Management Tracking and Reporting needs any kind of improvement that would cost $1.1 million. Therefore, DRA recommends that the Commission reject PG&E's request for funding the Improved Transportation Tracking System.

Similarly, the Commission should reject PG&E's request for funding for its Fleet Management Optimization project. PG&E claims that the Fleet Management Optimization is a project that uses two key applications to manage vehicle operations: Engineering Ordering System (EOS) and FA. PG&E describes FA and EOS as follows:

> FA was implemented in 2010 to replace the Total Equipment Asset Management System as TS' system of record for managing vehicle history and costs, for preventative maintenance and repair activity, mileage records, vehicle domiciled location, current possessor of the vehicle, and vehicle licensing and registration. …
>
> EOS is a 17-year-old home grown system with 14 years of extensive customizations having caused the system to become bloated and inefficient, making integration with new and upgraded systems increasingly difficult, particularly where FA is concerned. This initiative will re-write code to interface with the latest technologies, allowing for better integration with other applications (for example SAP, FA and

[1593] Ex. 30 (PG&E-7), p. 3-17.

> Power Plant), for creating or modifying purchase orders, performing goods receipts, the creation of capital orders, and the managing of assets. Included in this upgrade are electronic vehicle request forms to streamline ordering and replacement of up to 4,000 vehicles annually[1594].

Here again, PG&E seeks to meet its burden of prove by equivocation. It is interesting to note that the last recorded cost for TS in MWC JV was $303,000 in 2010 and that was to implement FA. However, while PG&E sought funding and approval to implement FA in 2010, it did not see fit to seek funding and approval to "upgrade EOS" at the time even though it now claims that EOS "is a 17-year-old home grown program" that is not compatible with FA in the first place. Now to replace or upgrade EOS, PG&E would need two times the cost it needed to implement FA, which is probably the dominant program of the two in the Fleet Management Application Optimization process.

PG&E does not anticipate any significant cost savings as a result of the Fleet Management Application process and has not provided sufficient information to support the need for optimization of the process. Given PG&E's other TS initiatives for test year 2014 GRC that DRA does not oppose, i.e. "IT Infrastructure Optimization", "Vehicle Safety and Operations Tracking and Reporting" and "Field Enablement of IT Systems in Garages", the Commission should reject the Fleet Management Optimization process and the Improved Transportation Compliance Management Tracking and Reporting for TS MWC JV and approve DRA's recommendation for $1.350 million for this major work category.

7.3.2 Capital Expenditures

TS capital expenditures are group under five numbered categories: MWC 04, 05, 28, 2F and 20. MWC 04 records PG&E's vehicle replacement cost, MWC 05 records capital tools and equipment costs, MWC 28 records PEV charging infrastructure costs, and MWC 2F records Build IT Applications. PG&E's TS capital needs forecast for test year 2014 is $139.3 million. PG&E acknowledges that its "2014 capital request for TS, represents an 81 percent increase from the base year 2011 recorded costs", 64 percent or $40 million of which is driven by vehicle replacement, while the rest is split among the other major work categories for TS capital[1595].

[1594] Ex. 30 (PG&E-7), p. 3-18.

[1595] Ex. 30 (PG&E-7), p. 3-2.

7.3.2.1 MWC 04 Fleet/Auto Equipment Replacement

MWC 04 includes all of PG&E's fleet replacement capital expenditures associated with TS, including automobiles, trucks, trailers and any power-operated equipment mounted on any of these assets or off-road equipment.

PG&E forecast for MWC 04 capital expenditures in 2014 is essentially equal to the total capital forecast for all TS categories in 2013. TS capital expenditure forecast for MWC 04 in 2013 is $145.5 million, while the total TS capital expenditure forecast for 2013 is $146.6 million. The difference between MWC 04 forecast and the total capital forecast for all TS categories in 2014 was about $6 million[1596]. However, PG&E forecast for MWC 04 in 2012 was $137.9 million, but the actual expenditure for MWC 04 in 2012 was $171.7 million.

Notwithstanding these facts, DRA made rather modest adjustments to PG&E's requests under TS MWC 04, accepting PG&E's actual costs for 2012 while adjusting the 2013 and 2014 forecast to be consistent with information DRA received on discovery.

> In addition to the vehicle-related capital expenditures in TS, PG&E also included the 2012 and 2013 forecasts for additional vehicles in Exhibit PG&E-3, Chapter 8, Gas Distribution Capital and Investment Planning. In Exhibit PG&E-3, under MWC 05 – Tools and Equipment, PG&E includes the forecast for 2012 capital expenditures for vehicles for an additional 40 gas service representatives (GSRs). The forecast for 2013 ($13.4 million) includes the purchase of additional vehicles for maintenance and construction (M&C) to support increasing capital and Operations and Maintenance work. In response to DRA data request, PG&E provided 2007 – 2011 capital expenditures for vehicles purchased for Gas Distribution M&C crews.
>
> Given that the 5 year average is $15.3 million and that PG&E has hired the 40 GSRs, DRA accepts PG&E's 2012 and 2013 forecast of fleet costs discussed in Exhibit PG&E-3. PG&E forecasted $2 million in 2012 and spent $3.1 million which PG&E said they transferred to Shared Services. DRA accepts the 2013 capital forecast of $13.4 million (in Exhibit PG&E-3) and removed it from MWC 05 in Gas Distribution Capital and Investment Planning and added it to MWC 04 under Transportation Services.

[1596] TS capital expenditure forecast for MWC 04 in 2014 is $132.9 million, while the total TS capital expenditure forecast for 2014 is $139.3 million.

> PG&E forecasts purchasing 470 new vehicles totaling $114.3 million in 2013, and 309 new vehicles totaling $80.3 million in 2014 for environmental compliance. ... A review of PG&E's data response shows that average unit costs are forecasted to increase 42% to 52% from 2012 to 2013 for On-Road compliance. Historical unit averages have increased 23% to 25%. The large increase from historical norm is not reasonable and should be adjusted. DRA used an average of 2011 and 2012 unit cost and applied this average unit-cost to the number of PG&E's On Road replacement units. As such, DRA reduced vehicle purchase forecast by $35.4 million in 2013.
>
> DRA's forecast for 2013 for MWC 04 is $89.6 million. 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 2014 capital. As such, DRA reduced PG&E's MWC 04 to $99.2 million for 2014[1597].

PG&E claims that DRA's reduction of MWC 04 forecast for 2013 and 2014 by $69.2 million and $33.8 million respectively "would not allow TS to purchase vehicles to comply with state and federal vehicle regulations"[1598]. However, PG&E failed to address the very reasons DRA gave for making these adjustments, focusing only on the fact that DRA had averaged recorded historical data to arrive at its recommendation.

In the absence of any reasonable evidence to support PG&E's hyperbolic assertions about safety, risk and legal compliance, this Commission has made it clear that it is acceptable to use historical data as the basis for a test year recommendation and PG&E has done it on numerous occasions in the past. In making this recommendation, DRA noted:

> A review of PG&E's data response shows that average unit costs are forecasted to increase 42% to 52% from 2012 to 2013 for On-Road compliance. Historical unit averages have increased 23% to 25%.[1599]

PG&E's focus on the averaging of historical data as its primary refrain on all of DRA's recommendations in all testimony betrays PG&E's own lack of evidence to support the higher unit averages it has uses to justify its vehicle replacement costs. Essentially, PG&E's position on those vehicle replacement costs is as follows:

[1597] Ex. 86 (DRA-18), pp. 19 -20.

[1598] Ex. 30 (PG&E-7), p. 3-11.

[1599] Ex. 86 (DRA-18), p. 19.

Q.31 Explain how the cost of replacement vehicles varies year to year?

A.31. Table 3-8 below plots the many types of vehicles TS purchased in 2012 and 2013, and identifies the number of vehicles purchased in each category and the average cost of the vehicles. For illustrative purposes, I used the vehicles to be replaced under a CARB Alternative Compliance Plan, On-Road Group 2 and Group 3, consistent with the pool of vehicles DRA used in its analysis. The only conclusion reasonably drawn from the chart is that the number and value of vehicles replaced vary each year…[1600]

It is unclear what PG&E is trying to say with this response to DRA's objection to the higher unit costs PG&E uses to justify its exaggerated forecasts. The notion that "[t]he only conclusion reasonably drawn from the chart is that the number and value of vehicles replaced vary each year" equally means that PG&E cannot explain its higher unit costs any more than DRA can because the only evidence PG&E has provided for that purpose by PG&E's own admission is inconclusive on the matter. However, the data also shows that PG&E has substantial control in the selection of the vehicles to serve its purposes, such that PG&E may make the unit cost higher when PG&E wants to or lower when it soothes PG&E's purposes.

Rather interestingly, PG&E then argues that a unit cost increase of 18.5 percent to 21 percent is the reasonable unit cost increase not the 42 percent to 52 percent that DRA found PG&E's forecast to be based on. However, PG&E claims that to reach that reasonable unit cost increase, the Commission should use a different mathematical formula than a straight average.

Q. 34 Is it true that TS' vehicles forecast for 2013 is 42 to 52 percent higher than 2012?

A. 34 No. TS calculations shows that PG&E's increase in average vehicles costs are only 21 percent for 2012 and 18.5 percent for 2013. These percentage increases are also well within the 23 to 25 percent historical and expected increase that DRA calculated.

TS arrived at these percentages by using the same information DRA relied upon for its calculation, which is the same data in Table 3-8.

Q. 35 If TS used the same information that DRA relied upon, then how is it that DRA's calculations are so different from TS' calculations?

[1600] Ex. 30 (PG&E-7), p.3-12.

> A. 35 TS and DRA both analyze CARB vehicle purchases for 2012 and 2013. TS used this information to calculate a fully *weighted* average of the average cost of these vehicles. On the other hand, DRA's calculation weights two vehicles groups separately in order to calculate its higher percentage increase for the average cost of these vehicles. This accounts for the difference. [Emphasis in original.][1601]

In the effort to reach the same average the DRA reached, believing it to be the more reasonable average than the 42 to 52 percent average of its forecast, PG&E forgot the first part of the calculation that led DRA to believe that the more reasonable average should be 23 to 25 percent. "Historical unit averages have increased 23% to 25%."[1602] DRA first took an average of historical unit costs and found them to be 23 to 25 percent, then using the same formula with which it determined that historical unit averages have been 23 to 25 percent calculated the forecast unit averages. PG&E has not done a weighted unit average of historical unit cost to support its conclusion. Therefore, its conclusion is logically flawed and unreasonable.

7.3.2.2 MWC 05 – Capital Tools & Equipment

MWC 05 forecasts costs for fleet related capital tools and equipment and the maintenance and updating of environmental equipment. PG&E forecast for MWC 05 in 2012 was $900,000, but PG&E recorded costs 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 3-year (2012-2014) capital expenditure forecast for MWC 05, but reduced PG&E's 2013 MWC 05 capital forecast by $520,000 to compensate for PG&E exceeding the 2012 forecast by the same amount.

7.3.2.3 MWC 28 – PEV Charging Infrastructure

PG&E forecasts costs for the development of new electric powered vehicles charging infrastructure and claims that it anticipates an increased need for such charging infrastructures for its growing fleet of EVs. MWC 28 recorded capital expenditure for EV charging infrastructure was $215,000 in 2011, but PG&E is forecasting an increased need for this infrastructure with the following forecasts for 2012 to 2014: (1) $680,000 in 2012; (2) $200,000 in 2013; and (3) $2.4 million in 2014. The escalation of these costs in 2014 is purportedly based

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[1601] Ex. 30 (PG&E-7), p. 3-14.

[1602] Ex. 86 (DRA-18), p. 19.

on PG&E's projected addition of 743 light-duty EVs and 333 medium and heavy-duty EVs during the 2014-2016 timeframe. PG&E claims that TS will install 962 Level 2 (220v) charge stations and 126 Level 1 (120v) charge stations to support the eWims planned for deployment[1603].

PG&E provided no evidence to support how it determined the number of charging stations that would be necessary to support the increase in EV vehicles, whether light, medium or heavy-duty or the consequences of using a smaller number of charging vehicles to support the projected deployment. However, PG&E cannot deny that the deployment of these vehicles is completely within its control and can be managed to reduce the rate impact of a perfect-storm of rate increases in all lines of businesses.

Notwithstanding these facts, DRA's recommended just a modest adjustment to TS capital expenditure forecasts for MWC 05.

> PG&E forecasted 2012 capital expenditures for MWC 28 as being $680 thousand. PG&E's actual recorded cost was $1.06 million. As such, PG&E exceeded its 2012 forecast by $383 thousand. DRA accepts PG&E's actual 2012 recorded costs and decreased PG&E's forecasted 2013 capital expenditure by $383 thousand. DRA also adjusted PG&E's 2014 forecasted capital for MWC 28 to 80% of forecast. DRA recommends the 20% adjustment to PG&E's forecast based on data which shows that PG&E's actual recorded costs were 80% of the estimated forecast for completed EV charging projects, as demonstrated by the results from updated workpaper WP3-223 provided in data response GRC2014-Ph-1_DR_DRA_153-Q13.[1604]

DRA recommends that the Commission adopt its recommendation for a 20 percent adjustment to PG&E's forecast MWC 28 capital costs for 2014 consistent with results from PG&E's updated work-papers.

7.3.2.4 MWC 2F

> PG&E's TS recorded capital for MWC 2F in 2011 of $64,174 for Revision 1 of Fleet Management System Implementation. PG&E forecasts IT Applications and Infrastructure (MWC 2F) capital at $3.1 million in 2014, $2.4 million in 2015, and $1.2 million in 2016.

[1603] Ex. 30 (PG&E-7), p. 3-32.

[1604] Ex. 86 (DRA-18), p. 21.

> As discussed in the expense section of this section, DRA recommends that ratepayers not be required to fund two IT projects proposed by PG&E. As such, DRA has reduced PG&E's capital forecast for MWC 2F in 2014. DRA recommends $0.0 million of capital expenditures in 2012, $0.0 million in 2013, and $1.6 million in 2014.[1605]

DRA recommends that the Commission approve $1.6 million for TS capital expenditures under MWC 2F for 2014.

7.4 Supply Chain – Materials and Logistics and Planning

PG&E's Supply Chain – Materials Logistic and Planning (MLP) maintains inventory of supplies and provides materials and services to other PG&E line of business (LOB) partners, including providing the necessary materials and services to support "PG&E's ongoing maintenance and construction activities".[1606] Warehousing, transportation logistics, supplier quality assurance, materials field services (MFS), inventory planning, inventory control and management, investment recovery and emergency response are all services MLP provides to the Company[1607].

7.4.1 Expense

The major work categories under MLP expense forecasts are MWC BI (Maintain Buildings) and MWC JV (Maintain IT Applications and Infrastructure). PG&E forecast $1.3 million for test year 2014 MLP expense and states that "[r]ecorded expense for MLP was $0 for MWC BI [in 2011] and $1.2 million [for MWC JV] in 2011". PG&E also explains that the 2011 recorded expenditures and the 2014 forecast expenditures for MLP are one-time projects that do not lend themselves to year-to-year comparisons[1608]. However, they do lend themselves to cost-benefit analysis but PG&E has not conducted any.

MLP capital expenditure forecast consists of four numbered MWCs – 05 (Tools and Equipment), 21 (Miscellaneous Capital), 22 (Maintain Buildings) and 2F (Build IT Applications and Infrastructure). PG&E forecast $1.4 million for MLP capital in 2012, $0.8 million in 2013

[1605] Id., p. 23.

[1606] Ex. 30 (PG&E-7), p. 4-1.

[1607] Ex. 86 (DRA-18), p. 24.

[1608] Ex. 30 (PG&E-7), p. 4-1.

and $7.8 million for 2014. Although PG&E also forecast MLP capital expenditure for 2015 and 2016, DRA did not address the forecast for those years as they fall outside this test-year GRC time-frame. DRA's decision not to address the 2015 and 2016 forecast that PG&E has included in this proceeding should not be construed as DRA's acceptance of, or acquiescence with, those forecasts in this or any future test-year GRCs.

DRA has no objections to PG&E's MLP 2014 forecast for MWC BI (Maintain Buildings) and thus accepts the forecasted amount of $211,000, but DRA reduced PG&E's 2014 forecast for MWC JV (Maintain IT Apps and Infrastructure) to $194,000 from $1.11 million. Similarly, for MLP capital expenditure forecasts, DRA does not object to PG&E's requests for MWC 05 (Tools & Equipment), MWC 21 (Miscellaneous Capital), and MWC 22 (Maintain Buildings), but DRA reduced PG&E's forecast for MWC 2F (Build IT and Applications and Infrastructure) for both 2012 and 2014. PG&E's MWC 2F forecast for 2013 was $0.

The following discussion only addresses those MWC forecasts that DRA has objected to: (1) MWC JV (Maintain IT Apps and Infrastructure) and MWC 2F (Build IT Application and Infrastructure).

7.4.1.1 MWC JV (Maintain IT Applications and Infrastructure.)

PG&E's MWC JV seeks to implement two initiatives known as Materials Advanced Planning system and Transportation Management System (TMS). PG&E claims that its current material planning and forecasting system does not provide network inventory transparency that consistently maintains product availability in the right location for internal clients[1609]. "In addition, the current planning system's capability does not align with the sporadic demand patterns intrinsic to a gas and electric utility's maintenance and construction LOB."[1610] Therefore, PG&E seeks to replace its current inventory planning system with the Materials Advanced Planning and Scheduling System.

PG&E claims that within two years of implementation, this system would enable it to offset PG&E's inventory investment by up to $5 million and reduce capital equipment investment by up to $3 million (relative to work/demand levels). After reviewing PG&E's

[1609] Ex. 30 (PG&E-7), p. 4-21.

[1610] Id., pp. 4-21 to 4-22.

workpapers and application as well prior rate case information on this system, DRA's report recommended as follows:

> DRA recommends that the Materials Advanced Planning and Scheduling not be funded by ratepayers as the funds were requested in the 2011 rate case and implementation was deferred due to functional dependencies on other supply chain SAP enhancements.[1611] As such, PG&E already received the funds and ratepayers should not have to fund this project twice. Further, ratepayers should be receiving the benefit in cost savings already.[1612]

If in fact the Materials Advanced Planning and Scheduling system had the potential to provide such benefits as PG&E claims, with two years of the first date it is rolled out. It would indeed seem like a project PG&E would have requested and done a long time ago. It turned out that PG&E has in fact requested funds for this initiative as recently as its last rate case but failed to use those funds for the purpose requested. Therefore, the Commission should not authorize another set of funds for the same system.

DRA does not oppose PG&E's forecast for TMS. However, DRA adjusted the forecast cost to 86 percent of PG&E's forecast.

> As discussed more fully later in this report, DRA reviewed PG&E's IT Concept Estimating Tool forecasts from the 2011 GRC with recorded data and determined that actual results have been 86% of forecast based on the use of that tool. As such, DRA makes a similar adjustment to the Transportation Management System project forecast for 2014.[1613]

TMS forecasted costs are for the purchase and implementation of a SAP that is compatible with TMS's current manual processes. PG&E has already implemented a SAF-EWM system in 2011 that would integrate with other existing applications the Company already has to provide advanced strategic and tactical planning, route optimization and other benefits, once an SAP system compatible with TMS's current manual process is implemented.[1614]

[1611] Ex. 30, PG&E-7, p. 4-24 and PG&E Data Response to DRA data Request 252 Q01: "Yes, PG&E's 2011 forecast revenue requirement did include funding for the advanced planning and scheduling system because PG&E planned to implement the project during the 2011 GRC period."

[1612] Ex. 86 (DRA-18), p. 27.

[1613] Id.

[1614] Ex. 30 (PG&E-7), p. 25.

7.4.2 Capital Expenditures

In Transportation, MWC 2F is the corresponding capital expenditure for the same project that MWC JV was in the expense forecast. Therefore, any adjustments to MWC JV must be reflected in MWC 2F and vice versa.

> The 2014 and 2015 capital forecast of $4.3 million and $2.1 million under MWC 2F are to implement the Materials Advanced Planning and Scheduling system and the Transportation Management System initiatives.[1615]
>
> As discussed above in the MWC JV, DRA recommends that ratepayers not fund the Materials Advanced Planning and Scheduling system as PG&E had requested funding for this project in the 2011 GRC.
>
> DRA does not oppose the proposed Transportation Management System initiative, but does make an adjustment to 86% of PG&E's forecasted cost. The 86% adjustment reflects PG&E's actual results of other IT projects that PG&E had forecasted using the same IT concept estimate tool from the 2011 GRC.[1616]

7.5 Supply Chain – Sourcing Operations

Procurement of materials necessary for PG&E to serve its customers is the responsibility of Supply Chain –Sourcing Operations. In 2011, PG&E procured $4.4 billion in such goods and services, of which 77 percent was for procurement of services and 23 percent for materials purchases[1617]. The materials purchased included distribution equipment such as transformers, pipe, cable, fabricated and structural steel, software and equipment, chemicals, lubricants and other oil products, construction equipment (both purchases and rentals), vehicles and automotive parts, etc.

7.5.1 Expense

The MWCs in Sourcing are: MWC JL (Procure Materials and Services) and MWC JV (Maintain IT Applications and Infrastructure.)

[1615] Id., p. 4-21.

[1616] Ex. 86 (DRA-18), pp. 29 – 30.

[1617] Id., p. 5-1.

PG&E forecasts that Sourcing expense needs will increase by $6.4 million in 2014 over 2011 expenditures for a total forecast of $13.1 million.

7.5.1.1 MWC JL – Procure Materials and Services

PG&E's forecast for MWC JL in 2014 is $9.7 million. PG&E used 2011 as the base year for this forecast and escalated labor and non-labor costs based on PG&E's own escalation guidelines. The average cost per employee was determined from historical labor and related costs and used to adjust for additional headcount costs.

DRA used a five-year (2008 – 2012) average of recorded costs, escalated to 2014 dollars, to determine the appropriate forecast for MWC JL 2014 forecast and recommends that the Commission approve $7.3 million for test year 2014. DRA maintains that "a five-year average is the appropriate method as the recorded amounts in the table above lack a clear pattern and the year-to-year variance is low, with movement in both directions."[1618]

7.5.1.2 MWC JV – Maintain IT Applications and Infrastructure

PG&E seeks to implement the following three IT initiatives in this test year 2014 GRC: 1) Supplier Relationship Management Technology/Functional Upgrade; (2) Supplier Performance Management; (3) Integrate supply Chain with Energy Content Management.

According to PG&E, Supply Chain Sourcing "utilizes SRM software as the primary purchasing system to process purchase order workflow from requisition to integration into PG&E SAP financial system"[1619]. PG&E wants to upgrade the SRM system to Version 7.03 at a cost of about $17.8 million, of which $2.7 million is forecasted for 2015. The 2014 forecast expense for the SRM upgrade is $2.5 million. PG&E claims that upgrading SRM to Version 7.02 is critical to the productivity of the various lines of business and their compliance with their various obligations.

DRA does not oppose PG&E's efforts to upgrade SRM to Version 7.02, but recommends that the Commission normalize the expense over three years and that the forecast amount be reduced to 86 percent of the forecast to reflect the actual result of 2011 GRC projects that relied on PG&E's Concept Estimating Tool for IT. This recommendation is also consistent with all of

[1618] Ex. 86 (DRA-18), p. 32.

[1619] Ex. 30 (PG&E), p. 5-23.

DRA's recommendation for all Shared Services and IT projects that relied on the Concept Estimating Tool in this GRC.

DRA objects to the second IT initiative, Supplier Performance Management Technology, that PG&E proposes for the Supply Chain Sourcing. PG&E forecast $0.5 million to implement the Supplier Performance Management Technology. According to PG&E:

> This program includes formalized meetings between suppliers and PG&E executives multiple times a year to review the suppliers performance. The primary goals of the program are to enhance the relationship with key suppliers that provide critical goods and services and identify opportunities for continuous improvement. A standardized supplier scorecard is used to measure supplier performance and hold suppliers accountable. Sourcing's stated goal is for these suppliers to achieve a 90 or better score out of a potential 100 points. If they do not score well enough, they know that PG&E may need to switch to alternative sources of supply. Suppliers are scored on areas that impact cost, public an employee safety, operations and quality, customer satisfaction, supplier diversity, and sustainability.[1620]

This description of a formalized Supplier Performance Management program seems very much like PG&E's employee doing the work they are paid salaries to do under the guise of a program for which PG&E can then seek special funding in this rate cycle. PG&E claims that the current score-carding process is Microsoft Excel-based and requires extensive manual effort by Sourcing employees and creates delays. "The new system would not only have links and interfaces to data sources to pull information without intervention, but there would be a supplier front-end as well where approximately 100 suppliers can input information."[1621].

PG&E testimony never actually names the application that would replace the excel spreadsheet method that it has used to date, or explain how it would completely eliminate the requirement to manually input the data in a manner unlike the excel spreadsheet.

Similarly, PG&E's third IT initiative for Supply Chain Sourcing would integrate Supply Chain Sourcing with Enterprise Content Management by digitizing physical documents and migrating the existing content to the Company's Enterprise Content Management platform at a forecast cost of $0.3 million for 2014.

[1620] Ex. 30, p. 5-27.

[1621] Id., p.5-28.

DRA recommends that the Commission reject the second and third IT initiatives proposed by PG&E to formalize meetings with suppliers and digitize physical documents. Given all the areas in this GRC that PG&E has requested digitizing physical documents as part of the migration to its new ECM platform, ratepayers are probably already duplicating funding for this process in this and earlier GRCs.

7.5.2 Capital Expenditures

PG&E's forecast for Supply Chain Sourcing Capital funding for IT initiatives is $10 million for 2014 and $4.8 million for 2015. Of these amounts, the Supplier Relationship Management 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 Enterprise Content Management, which PG&E forecast for 2014 at $1.6 million and $0.7 million in 2015.

PG&E does not forecast capital funding for implementing the Supplier Performance Management Technology program, which again reflects the fact that it primarily consists of PG&E's employees doing they work they were retained to do.

Consistent with DRA's recommendations under MWC JV in the preceding discussion, DRA recommends that the Commission approve the capital funding for the Supplier Management Technical/Functional Technology upgrade program, but reduce the authorized funding to 86 percent of the forecast to reflect actual results of such implementation in the 2011 GRC. This would reduce PG&E's forecast of $10 million to $7.3 million in 2014. DRA does not make any recommendations for the 2015 forecast as it is outside the current rate cycle, but DRA decision not to address the 2015 forecast at this time should not be viewed as an acceptance of that forecast or acquiescence with it[1622].

DRA recommends that the Commission deny approval of PG&E's forecast capital funding to integrate Supply Chain with Enterprise Content Management.

[1622] Ex 86 (DRA-18), p. 34.

7.6 Real Estate

Shared Services and IT Real Estate consists of costs associated with managing PG&E's common utility plant buildings and yards, which include but are not limited to office buildings, service centers, shops, warehouses, construction and equipment yards, vehicle maintenance garages, customer service offices, Contact centers, data centers, and meetings and training facilities[1623].

PG&E's 2014 expense forecast for Corporate Real Estate is $32.6 million. PG&E acknowledges that recorded adjusted expense for 2011 was $12 million. Thus, the 2014 forecast is 172 percent more than 2011 recorded adjusted expense. PG&E claims that the primary reasons for this escalation are:

- Additional costs to maintain the Company's aging buildings and yards.
- Increased costs to complete building seismic safety upgrades.
- Additional costs to ensure compliance with the requirements of the ADA and Title 24 of the California Code and Regulations regarding accessibility at other Company buildings in addition to customer service offices.
- Expenditures to improve and provide additional offices space, rebuild outdated and inefficient service centers, and provide new buildings and yards to support PG&E's business needs.[1624]

None of the activities that PG&E now claims form the basis of the 172 percent escalation in costs from 2011 to 2014 are of recent origin. In fact, PG&E has been or should have been at work on all these activities for more than a decade.

Capital funding forecast for Corporate Real Estate in this rate cycles are: (1) $48.976 million for 2012, (2) $40.448 million for 2013 and $81.602 million for 2014. PG&E also forecast capital funding costs for 2015 and 2016, but DRA has not responded to forecasts that are outside this rate cycle.

7.6.1 Expense

Both the expense forecast and the capital forecasts are grouped into MWCs. The expense forecast MWCs for Real Estate are as follows:

[1623] Ex. 86 (DRA-18), p. 34; Ex. 30 (PG&E-7, p. 6-1.

[1624] Ex. 30 (PG&E-7), p. 6-2.

(1) MWC BI (Maintain Building) - $24.903 million;

(2) MWC JH (Implement Real Estate Strategy) - $6.837 million; and

(3) MWC JV (Maintain IT Applications and Infrastructure) - $850,000.

7.6.1.1 MWC BI – Maintain Buildings

MWC BI comprises of the following programs: a) Base Building Program; b) Building Seismic Safety Program and c) ADA Compliance Program. PG&E's test year 2014 forecasts for Base Building Program is $14.803 million, $4.191 million for Building Seismic Safety Program and $5.909 million for ADA Compliance Program[1625]. In 2011, the recorded adjusted costs for these same programs were $3.376 million, $2.714 million and $2.823 million, respectively[1626].

As previously noted none of these programs are new and PG&E would have been working on these programs for at least a decade. Further, there is no particular change in circumstances that suggests that Corporate Real Estate is facing challenges that are far more than it faced in 2011. Therefore, DRA uses a five-year average of recoded data from 2007 to 2012, escalated to 2014, to forecast PG&E's 2014 MWC BI funding.

Further, PG&E has made these exaggerated claims in the past. In the 2011 GRC, the Commission authorized $26.5 million for Corporate Real Estate MWC BI "but [PG&E] reduced its budget for MWC BI by $18.2 million to $8.3 million" upon the grounds that it need to fund higher priority work in other parts of the Company[1627].

PG&E argues that DRA's recommendation failed to take into account its "127 pages of testimony and 964 pages of detailed workpapers to support its real estate forecasts". This argument is preposterous. DRA reviewed all of the evidence and found them unconvincing to support a cost escalation that is 172 percent above what PG&E requested and was approved for just two years previously. Much of the 127 pages of testimony that PG&E claims supports its real estate forecasts consist of descriptions of PG&E's facilities[1628] and a general statement that seismic project would make structural upgrades to the facility[1629].

[1625] Ex. 30 (PG&E-7), p. 6-105.

[1626] Id,

[1627] Ex. 86 (PG&E-7), p .38.

[1628] Ex. 30 (PG&E-7), pp. 6-44 to 6-50; 6-66 to 6-95.

[1629] Id., p. 6-47.

e) Stockton Gas Plant

This project will make structural upgrades to the Stockton Gas Plant building to meet the minimum PG&E design performance level of "Life Safety." The project will mitigate the seismic vulnerabilities of the building and also includes ADA improvements required by the local building department as part of the seismic upgrade permit. The forecast cost of the seismic upgrade at the Stockton Gas Plant is $1.2 million expense in 2012.

f) Livermore Office

This project will make structural upgrades to the Livermore Office building to meet the minimum PG&E design performance level of "Life Safety." The Livermore Office also houses PG&E's Livermore customer service office (CSO). The project will mitigate the seismic vulnerabilities of the building and also includes ADA improvements required by the local building department as part of the seismic upgrade permit. The forecast cost of the seismic upgrade at the Stockton Gas Plant is $1.0 million expense in 2012.

…

h) Santa Maria Service Center

This project will make structural upgrades to the Garage and Office/Warehouse buildings at the Santa Maria Service Center to meet the minimum PG&E design performance level of "Life Safety." The project will mitigate the seismic vulnerabilities of the building and also includes ADA improvements required by the local building department as part of the seismic upgrade permit. The forecast cost of the seismic upgrade at the Santa Maria Service Center is $1.2 million expense in 2012.[1630]

Except for the names of the facilities and in the case of Livermore the acknowledgement that the building also houses a CSO, all the descriptions are identical. It is unreasonable for PG&E' to argue that unless DRA has addressed each of these generalizations, DRA has not reviewed them or considered them in its analysis. DRA did not discuss these explanations separately and individually because they are simply not unconvincing and provide no evidence that deserves a response.

[1630] Ex 30 (PG&E-7), pp. 6-47 to 6-48.

The main drivers for Corporate Real Estate activities are all events that increase gradually from year to year, and the Commission has recognized that it is appropriate to use recorded costs to estimate the test year forecast for such activities or events.

Notwithstanding this fact PG&E argues:

> Using recorded expenditures as the primary tool to forecast future real estate costs is inappropriate because the Company's real estate forecasts are bottom-up forecasts that identify the specific projects needed to maintain and improve the Company's aging buildings and yards, achieve building seismic safety, comply with ADA and other regulations, increase the operating reliability of buildings that support critical business functions, and implement real estate solutions required to meet changing business needs.[1631]

The telling sentence in the foregoing argument is that "the Company's real estate costs forecasts are bottom-up forecasts", this means that the Company's real estate forecasts in the five years that DRA used for its average estimate were derived with the same bottom-up method that PG&E used in this 2014 rate case. Therefore, unless PG&E is claiming that the specific projects it needs to maintain and improve the Company's aging buildings and yards or comply with ADA and other regulations changes from year to year, the prior years recorded history forms the best basis for forecasting PG&E's future needs. As DRA noted, "maintenance should be a regular recurring event that can be planned and managed"[1632]. The delta between the recorded adjusted costs for MWC BI from year to year bears witness to this DRA testimony.

PG&E's protest of DRA's estimate for its Corporate Real Estate expense forecast continues:

> Q. 18 What will be the consequence of using recorded expenditures to forecast future real estate expenditures?
>
> A. 18 If the Commission were to accept DRA's position, it would be agreeing to a "self-fulfilling" premise that would never allow PG&E's real estate program expenditures to increase significantly above recorded expenditures. DRA's position that the Commission should not approve forecasts that are higher than the average of the Company's last five years of recorded expenditures is unreasonable for three reasons: (i) First, it

[1631] Ex. 30 (PG&E-7), p. 6-7.

[1632] Ex. 86, p.38.

> ignores current and future conditions that differ from past conditions; (ii) Second, it does not consider the appropriateness of the specific activities and projects comprising each of PG&E's real estate program forecast; and (iii) Third, it requires PG&E to spend more than authorized in order to show the higher level of recorded expenditures necessary to gain DRA's support for future (General Rate Case) GRC forecasts.[1633]

The foregoing discussion of the consequences of using recorded expenditures to forecast future real estate expenditures is a good example of why DRA should not be expected to address every single narrative pretext in PG&E's testimony before making a forecast recommendation for PG&E's Corporate Real Estate. The discussion deliberately ignores the facts, which DRA addressed in its testimony. Consider for instance the argument that using recorded expenditures "requires PG&E to spend more than authorized in order to show the higher level of recorded expenditures necessary to gain DRA's support for future."[1634] DRA noted that in 2011 PG&E was authorized $27.5 million … but reduced its budget for MWC BI by $18.2 million to $8.3 million." DRA explained PG&E's rationale for the reduction as follows:

> PG&E says the "[d]ecrease reflects the decision not to pursue in 2011 the following projects in order to fund higher priority work in other parts of the Company: (i) 77 Beal St./One Market Plaza project; (ii) Customer Office Refurbishment Project; (iii) certain non-mandatory ADA surveys; and (iv) certain Base Building maintenance projects (e.g., roofing repairs, HVAC repairs, carpet replacement, interior painting)."[1635]

These facts reflect that the rationale which supports using recorded cost averaging is that which requires PG&E to spend what it was authorized rather than more than it was authorized in order to show a higher level of recorded expenditure. The audacity with which PG&E makes this claim despite evidence to the contrary reflects the PG&E's attitude towards much of its recommendations for Shared Services and IT.

PG&E also argues that using recorded cost averaging "does not consider the appropriateness of the specific activities and projects comprising each of PG&E's real estate

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[1633] Ex. 60 (PG&E-22), p. 6-9.

[1634] Id.

[1635] Ex. 86, DRA-18, p.38, citing *Pacific Gas and Electric Company's August 3, 2011 Budget Report in Compliance with California Public Utilities Commission Decision 11-05-018, p.8.6.*

program forecasts."[1636] Consider PG&E's rationale for transferring funds from MWC BI to other projects outside in 2011. Among the projects deferred were 77 Beale Street/One Market Plaza project and certain non-mandatory ADA surveys. These same projects occupy more than 10 pages of discussions in this GRC[1637]. Here again the specific activities and projects comprising the real estate program forecasts, show that they do not support the 172 percent escalation of costs, when only two years ago they were considered lower priority work.

When one reviews each of the programs separately, PG&E's cases looks even worse. Discussing the ADA initiative for instance, PG&E stated:

> 1) Initiative to Enhance ADA Compliance at Company Buildings
>
> CRE Enhanced ADA Compliance Program will assure ADA Title 1 (employee accessibility) and Title 3 (public accessibility) to all CRE-managed buildings. When used in this chapter, "ADA compliance" is intended to include Title 24 compliance where appropriate.
>
> This initiative includes the cost of performing detailed ADA accessibility assessments at approximately 190 CRE-managed buildings. These surveys will establish updated accessibility condition information for each building, identify recommended accessibility improvements with the assistance of external ADA experts, and implement these recommendations.
>
> Following enactment of the ADA in 1992, CRE completed "readily achievable barrier removal" projects for ADA Title 1 and Title 3 compliance in its buildings. However, as noted above, those original efforts may be outdated and may no longer meet current ADA requirements.[1638]

First note that CRE completed ADA compliance on all its buildings following enactment in 1992, and now only wants to review its compliance status because "those original efforts may be outdated and may no longer meet current ADA requirements", to which one might well say: "On the other hand, they may still be in compliance." The point is that without knowing whether it is actually out of compliance, PG&E escalated its ADA forecast by more than one hundred

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[1636] Ex. 30 (PG&E-7), p. 6-9.

[1637] Id., 77 Beal St./ One Market Plaza: Page 6-95 to 6-100, p.6-25; ADA Compliance: Page 6-55 to 6-63, 6:25.

[1638] Ex. 30 (PG&E-7), pp. 6-56 to 6-57.

percent on pure speculation. The CPUC has had the same handicap ramp up the front of the building, the same size rest rooms, the same sitting spaces and other elements that usually comprise ADA compliance requirements for more than 10 years. Assuming they were in compliance at the time they were built and have not fallen out of compliance, how much should the CPUC spend in reviewing the likelihood that the facilities are not in compliance. It is important to note that PG&E seeks to conduct these surveys for all of its CRE managed buildings. It is unnecessary make work that would again result in funds being transferred to other areas that the Company identifies as higher-priority work.

7.6.1.2 MWC JH – Implement Real Estate Strategy

PG&E's Real Estate Strategy consists of the Real Estate Planning and Transaction program and the Real Estate Solutions program expensed in MWC JH. PG&E maintains that its Real Estate Planning and Transactions program will improve the management of vacant properties and reduce future costs of underutilized and surplus real estate[1639]. Real Estate Solutions program will form the basis for CRE to refurbish, relocate, replace and close offices and service centers to correct condition deficiencies, improve functionality, implement workplace improvement and meet business needs[1640].

PG&E's 2014 expense forecast for Real Estate Planning and Transactions program is $5 million dollars and for Real Estate Solutions is $2 million. In 2011, the recorded expense cost for Real Estate Planning and Transactions was $3.1 million and for Real Estate Solutions was $0[1641]. The total forecast funding for MWC JH for 2014 is $6.8 million to be exact and 76 percent higher than the 2012 actual recorded expense[1642]. In fact, PG&E's 2014 recorded expense forecast for MWC JH is higher than it has ever been in the last five years during which time it only exceeded $4 million once[1643].

[1639] Id.. p. 6-25.

[1640] Id.

[1641] Id., p. 6-102; Ex. 86 (DRA-7), pp. 39 – 40.

[1642] Ex. 86 (DRA-7), p. 40.

[1643] Id., See Table 18-35 showing recorded expense for MWC JH from 2007 to 2012 as $3.976 million, $4.586 million, $3.191 million, $3.250 million, $3.130 million, $3.887 million respectively.

DRA used a five year average of recorded expense, escalated to 2014, $4.04 million as the appropriate test year forecast for MWC JH[1644].

7.6.1.3 MWC JV – Maintain IT Applications and Infrastructure

MWC JV is the IT Applications and Infrastructure component of CRE's Base Building Program and the Real Estate Planning and Transaction Program. PG&E forecast $0.85 million for this program in test year 2014, with $0.65 million forecast for the Base Building Program and $0.2 million for the Real Estate Planning and Transactions program.

DRA opposes rate payer funding for MWC JV because PG&E was funded for a similar Real Estate Planning and Transactions program initiative in 2011 but PG&E did not implement the initiative. Regarding the Base Building Program initiative, DRA writes:

> While PG&E states that the total revenue requirement provided by the 2011 GRC decision was less than PG&E's 2011 GRC forecast and therefore insufficient to support all of the work forecast in PG&E's 2011 GRC testimony, PG&E's March 2012 Budget Report shows that PG&E had $608,000 left in its 2011 budget. … Ratepayers should not be required to pay twice.[1645]

7.6.1.4 MWC 22 (Maintain Building)

PG&E forecasts the capital cost for its Base Building Program and Building Seismic Safety Program in MWC 22. The Base Building Program capital costs consist of replacement costs that PG&E claims would "extend the life of building components, correct building component deficiencies, improve equipment-operating efficiencies, replace failed or functionally obsolete building components, and increase the operating reliability of PG&E's buildings and yards."[1646]

The Building Seismic Safety Program aims to improve the seismic performance of Company buildings located in areas predicted to experience a higher risk of strong seismic

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[1644] Id., p. 35.

[1645] Ex. 86 (DRA-7), p. 41.

[1646] Ex. 30 (PG&E-7), p. 6-26.

activity. PG&E has completed seismic safety work in 76 of its buildings and forecasts an additional 16 buildings to be completed in this rate cycle.[1647]

PG&E's 2014 capital expenditure forecast for its Base Building Program is $44.125 million and for its Building Seismic Safety Program is $1.549 million. In 2012 PG&E recorded costs for MWC 22 was $46.733 million.

DRA accepts PG&E's 2012 recorded costs for MWC 22 but recommends that the Commission use a five-year average forecasting methodology to set PG&E's test year 2014 costs.

The Commission should not rely solely on PG&E's forecast as the timing and scope of the projects included in its request are at the discretion of PG&E.

> PG&E's August 3, 2011 Budget Report Illustrates that the ratepayer funds provided in the 2011 GRC for MWC 22 (previously MWC 78 and MWC 88) have been used elsewhere. In that August 3, 2011 Budget Report, the MWC 22/23 (previously MWC 78) budget was decreased by $15.4 million from the GRC imputed amount of $65.4 million to $50 million. Also, MWC 22 (previously MWC 88) was decreased by $5.2 million from GRC imputed amount of $5.7 million to $0.5 million. …
>
> …DRA simply highlights the fact that … ratepayers should not pay based solely on what PG&E management wants, but rather based on what PG&E has delivered.[1648]

7.6.1.5 MWC 23 (Implement Real Estate Strategy)

MWC 23 represents capital cost for the Real Estate Strategy Solutions Program. PG&E's 2014 capital forecast for MWC 23 is $35.4 million. This 2014 forecast amount exceeds anything that has been recorded MWC 23 or its predecessor accounts in the past six years. "In fact, PG&E's 2014 request for MWC 23 exceeds what PG&E has spent in this MWC for the past six years combined."[1649] Recorded cost for Real Estate Solution Capital in 2011 was $6.4 million.

[1647] Id., p. 6-41 to 6-42.

[1648] Ex. 86(DRA-7), p. 43.

[1649] Id., p. 45.

DRA recommends that the Commission authorize $10 million for MWC 23 test year 2014 expenditure. "DRA's forecast is based on its recommendation that one project [in the Program] be rejected and that the remaining balance be normalized over three years."[1650]

One remarkable aspect of PG&E's escalation of its forecast for MWC 23 is the degree to which the work is both discretionary and cosmetic. Describing what it saw as the future state of Real Estate Solutions Program, PG&E stated:

> CRE forecast for the Real Estate Solutions Program includes expenditures to refurbish or replace office and service center buildings to correct condition deficiencies, improve functionality, implement workplace improvements, and meet current business needs. CRE's forecast for this program also includes expenditures to provide additional office space where needed, refurbish floors at 77 Beale Street and improve the operating reliability of the Fairfield data center.[1651]

DRA fails to understand why PG&E would oppose normalizing the cost of refurbishing floors and creating additional office space rather than creating a rate shock in a GRC that PG&E is planning the most ambitious optimization and improvement of every single asset it owns regardless of the need or benefit of doing so in one rate cycle.

The one project that DRA is opposed to including in MWC 23 is the plan to provide a dedicated 12kV power feed from the Cordelia Substation, located approximately six miles away, to the Fairfield Data Center. The project is essentially more of a question of convenience rather than need. The Fairfield Data Center has been superseded by PG&E's new Sacramento Data Center, which 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. In addition, CAISO maintains visibility with the same resources that the Data Centers are monitoring, and 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.

> Several utility power disruptions to the Fairfield Data Center have occurred since December 2011. While most disruptions were momentary, one outage was over 22 minutes in duration. Secondary systems such as

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[1650] Id., p. 45 illustrating the removal of the program and normalization of the remaining costs as follows: ($35.378 - $5,233)/3 + 10.048.

[1651] Ex. 86 (DRA-18), p. 6-66.

> uninterruptible power systems, batteries and standby generators are in place to support critical operations when utility power disruptions occur. However, any utility power disruption carries the potential of catastrophic data center failure if any of the secondary systems or system components fails.[1652]

In addition to the fact that there are cheaper alternatives to incurring this $5 million for a 12kV already available to the data center, PG&E upgraded the Fairfield Data Center in the period leading up to the 2011 rate cycle and did not see the need or urgency to add the dedicated 12kV line. Therefore, as the "Fairfield Data Center … already has secondary systems, DRA recommends not funding a dedicated power feed" to the Center[1653].

7.6.2 Capital Expenditures

Capital costs under MWC 2F are for Base Building Program and the Real Estate Planning and Transaction Program.

1.17.2.3 MWC 2F – Build IT Applications and Infrastructure

PG&E's 2014 forecast for MWC 2F is $0.350 million under the Base Building Program and $0.2 million for Real Estate Planning and Transmission program. The capital expenditure under the Real Estate Planning and Transmission Program is primarily to integrate CRE's stand-alone occupancy planning database with PG&E's information management systems.

PG&E identified both the Base Building Program and the Real Estate Planning and transaction Program in its 2011 GRC but claimed that total revenue requirement the Commission authorized for the 2011 GRC was insufficient to support all of the work forecast in PG&E's 2011 GRC testimony. By this rationale, unless the Commission approves the exact amount that PG&E requested in its GRC applications, PG&E has the discretion to refrain from implementing programs sought in that GRC and request the same programs again in subsequent GRCs ad infinitum.

DRA opposes ratepayer funding for Base Building Program and the Real Estate Planning and Transaction Program. PG&E has not spent its 2011 budgeted expense amounts for IT and should not be approved for more ratepayer funds for programs it has already presented to the

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[1652] Ex. 30 (PG&E-7), p. 6-102.

[1653] Id., p. 45.

Commission and received authorized funding in prior rate cases.Supply Chain – Materials and Logistics and Planning

PG&E's Supply Chain – Materials Logistic and Planning (MLP) maintains inventory of supplies and provides materials and services to other PG&E line of business (LOB) partners, including providing the necessary materials and services to support "PG&E's ongoing maintenance and construction activities".[1654] Warehousing, transportation logistics, supplier quality assurance, materials field services (MFS), inventory planning, inventory control and management, investment recovery and emergency response are all services MLP provides to the Company[1655].

7.6.3 Expense

The major work categories under MLP expense forecasts are MWC BI (Maintain Buildings) and MWC JV (Maintain IT Applications and Infrastructure). PG&E forecast $1.3 million for test year 2014 MLP expense and states that "[r]ecorded expense for MLP was $0 for MWC BI [in 2011] and $1.2 million [for MWC JV] in 2011". PG&E also explains that the 2011 recorded expenditures and the 2014 forecast expenditures for MLP are one-time projects that do not lend themselves to year-to-year comparisons[1656]. However, they do lend themselves to cost-benefit analysis but PG&E has not conducted any.

MLP capital expenditure forecast consists of four numbered MWCs – 05 (Tools and Equipment), 21 (Miscellaneous Capital), 22 (Maintain Buildings) and 2F (Build IT Applications and Infrastructure). PG&E forecast $1.4 million for MLP capital in 2012, $0.8 million in 2013 and $7.8 million for 2014. Although PG&E also forecast MLP capital expenditure for 2015 and 2016, DRA did not address the forecast for those years as they fall outside this test-year GRC time-frame. DRA's decision not to address the 2015 and 2016 forecast that PG&E has included in this proceeding should not be construed as DRA's acceptance of, or acquiescence with, those forecasts in this or any future test-year GRCs.

DRA has no objections to PG&E's MLP 2014 forecast for MWC BI (Maintain Buildings) and thus accepts the forecasted amount of $211,000, but DRA reduced PG&E's 2014

[1654] Ex. 30 (PG&E-7), p. 4-1.

[1655] Ex. 86 (DRA-18), p. 24.

[1656] Ex. 30 (PG&E-7), p. 4-1.

forecast for MWC JV (Maintain IT Apps and Infrastructure) to $194,000 from $1.11 million. Similarly, for MLP capital expenditure forecasts, DRA does not object to PG&E's requests for MWC 05 (Tools & Equipment), MWC 21 (Miscellaneous Capital), and MWC 22 (Maintain Buildings), but DRA reduced PG&E's forecast for MWC 2F (Build IT and Applications and Infrastructure) for both 2012 and 2014. PG&E's MWC 2F forecast for 2013 was $0.

The following discussion only addresses those MWC forecasts that DRA has objected to: (1) MWC JV (Maintain IT Apps and Infrastructure) and MWC 2F (Build IT Application and Infrastructure).

7.6.3.1 MWC JV (Maintain IT Applications and Infrastructure.)

PG&E's MWC JV seeks to implement two initiatives known as Materials Advanced Planning system and Transportation Management System (TMS). PG&E claims that its current material planning and forecasting system does not provide network inventory transparency that consistently maintains product availability in the right location for internal clients[1657]. "In addition, the current planning system's capability does not align with the sporadic demand patterns intrinsic to a gas and electric utility's maintenance and construction LOB."[1658] Therefore, PG&E seeks to replace its current inventory planning system with the Materials Advanced Planning and Scheduling System.

PG&E claims that within two years of implementation, this system would enable it to offset PG&E's inventory investment by up to $5 million and reduce capital equipment investment by up to $3 million (relative to work/demand levels). After reviewing PG&E's workpapers and application as well prior rate case information on this system, DRA's report recommended as follows:

> DRA recommends that the Materials Advanced Planning and Scheduling not be funded by ratepayers as the funds were requested in the 2011 rate case and implementation was deferred due to functional dependencies on other supply chain SAP enhancements.[1659] As such, PG&E already

[1657] Ex. 30, PG&E-7, p.4-21

[1658] Id., pp. 4-21 to 4-22

[1659] Ex. 30, PG&E-7, p. 4-24 and PG&E Data Response to DRA data Request 252 Q01: "Yes, PG&E's 2011 forecast revenue requirement did include funding for the advanced planning and scheduling system because PG&E planned to implement the project during the 2011 GRC period."

> received the funds and ratepayers should not have to fund this project twice. Further, ratepayers should be receiving the benefit in cost savings already.[1660]

If in fact the Materials Advanced Planning and Scheduling system had the potential to provide such benefits as PG&E claims, with two years of the first date it is rolled out. It would indeed seem like a project PG&E would have requested and done a long time ago. It turned out that PG&E has in fact requested funds for this initiative as recently as its last rate case but failed to use those funds for the purpose requested. Therefore, the Commission should not authorize another set of funds for the same system.

DRA does not oppose PG&E's forecast for TMS. However, DRA adjusted the forecast cost to 86 percent of PG&E's forecast.

> As discussed more fully later in this report, DRA reviewed PG&E's IT Concept Estimating Tool forecasts from the 2011 GRC with recorded data and determined that actual results have been 86% of forecast based on the use of that tool. As such, DRA makes a similar adjustment to the Transportation Management System project forecast for 2014.[1661]

TMS forecasted costs are for the purchase and implementation of a SAP that is compatible with TMS's current manual processes. PG&E has already implemented a SAF-EWM system in 2011 that would integrate with other existing applications the Company already has to provide advanced strategic and tactical planning, route optimization and other benefits, once an SAP system compatible with TMS's current manual process is implemented.[1662]

7.6.4 Capital Expenditures

In Transportation, MWC 2F is the corresponding capital expenditure for the same project that MWC JV was in the expense forecast. Therefore, any adjustments to MWC JV must be reflected in MWC 2F and vice versa.

> The 2014 and 2015 capital forecast of $4.3 million and $2.1 million under MWC 2F are to implement the Materials Advanced Planning and

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[1660] Ex. 86 (DRA-18), p. 27.

[1661] Id.

[1662] Ex. 30 (PG&E-7), p. 4-25.

Scheduling system and the Transportation Management System initiatives.[1663]

As discussed above in the MWC JV, DRA recommends that ratepayers not fund the Materials Advanced Planning and Scheduling system as PG&E had requested funding for this project in the 2011 GRC.

DRA does not oppose the proposed Transportation Management System initiative, but does make an adjustment to 86% of PG&E's forecasted cost. The 86% adjustment reflects PG&E's actual results of other IT projects that PG&E had forecasted using the same IT concept estimate tool from the 2011 GRC.[1664]

7.7 Supply Chain – Sourcing Operations

Procurement of materials necessary for PG&E to serve its customers is the responsibility of Supply Chain –Sourcing Operations. In 2011, PG&E procured $4.4 billion in such goods and services, of which 77 percent was for procurement of services and 23 percent for materials purchases[1665]. The materials purchased included distribution equipment such as transformers, pipe, cable, fabricated and structural steel, software and equipment, chemicals, lubricants and other oil products, construction equipment (both purchases and rentals), vehicles and automotive parts, etc.

7.7.1 Expense

The MWCs in Sourcing are: MWC JL (Procure Materials and Services) and MWC JV (Maintain IT Applications and Infrastructure.)

PG&E forecasts that Sourcing expense needs will increase by $6.4 million in 2014 over 2011 expenditures for a total forecast of $13.1 million.

7.7.1.1 MWC JL – Procure Materials and Services

PG&E's forecast for MWC JL in 2014 is $9.7 million. PG&E used 2011 as the base year for this forecast and escalated labor and non-labor costs based on PG&E's own escalation guidelines. The average cost per employee was determined from historical labor and related costs and used to adjust for additional headcount costs.

[1663] Id., p. 4-21.

[1664] Ex. 86 (DRA-18), pp. 29 – 30.

[1665] Id., p. 5-1.

DRA used a five-year (2008 – 2012) average of recorded costs, escalated to 2014 dollars, to determine the appropriate forecast for MWC JL 2014 forecast and recommends that the Commission approve $7.3 million for test year 2014. DRA maintains that "a five-year average is the appropriate method as the recorded amounts in the table above lack a clear pattern and the year-to-year variance is low, with movement in both directions."[1666]

7.7.1.2 MWC JV – Maintain IT Applications and Infrastructure

PG&E seeks to implement the following three IT initiatives in this test year 2014 GRC: 1) Supplier Relationship Management Technology/Functional Upgrade; (2) Supplier Performance Management; (3) Integrate supply Chain with Energy Content Management.

According to PG&E, Supply Chain Sourcing "utilizes SRM software as the primary purchasing system to process purchase order workflow from requisition to integration into PG&E SAP financial system"[1667]. PG&E wants to upgrade the SRM system to Version 7.03 at a cost of about $17.8 million, of which $2.7 million is forecasted for 2015. The 2014 forecast expense for the SRM upgrade is $2.5 million. PG&E claims that upgrading SRM to Version 7.02 is critical to the productivity of the various lines of business and their compliance with their various obligations.

DRA does not oppose PG&E's efforts to upgrade SRM to Version 7.02, but recommends that the Commission normalize the expense over three years and that the forecast amount be reduced to 86 percent of the forecast to reflect the actual result of 2011 GRC projects that relied on PG&E's Concept Estimating Tool for IT. This recommendation is also consistent with all of DRA's recommendation for all Shared Services and IT projects that relied on the Concept Estimating Tool in this GRC.

DRA objects to the second IT initiative, Supplier Performance Management Technology, that PG&E proposes for the Supply Chain Sourcing. PG&E forecast $0.5 million to implement the Supplier Performance Management Technology. According to PG&E:

> This program includes formalized meetings between suppliers and PG&E executives multiple times a year to review the suppliers performance. The

[1666] Ex. 86 (DRA-18), p. 32.

[1667] Ex. 30 (PG&E-4), p. 5-23.

> primary goals of the program are to enhance the relationship with key suppliers that provide critical goods and services and identify opportunities for continuous improvement. A standardized supplier scorecard is used to measure supplier performance and hold suppliers accountable. Sourcing's stated goal is for these suppliers to achieve a 90 or better score out of a potential 100 points. If they do not score well enough, they know that PG&E may need to switch to alternative sources of supply. Suppliers are scored on areas that impact cost, public an employee safety, operations and quality, customer satisfaction, supplier diversity, and sustainability.[1668]

This description of a formalized Supplier Performance Management program seems very much like PG&E's employee doing the work they are paid salaries to do under the guise of a program for which PG&E can then seek special funding in this rate cycle. PG&E claims that the current score-carding process is Microsoft Excel-based and requires extensive manual effort by Sourcing employees and creates delays. "The new system would not only have links and interfaces to data sources to pull information without intervention, but there would be a supplier front-end as well where approximately 100 suppliers can input information."[1669].

PG&E testimony never actually names the application that would replace the excel spreadsheet method that it has used to date, or explain how it would completely eliminate the requirement to manually input the data in a manner unlike the excel spreadsheet.

Similarly, PG&E's third IT initiative for Supply Chain Sourcing would integrate Supply Chain Sourcing with Enterprise Content Management by digitizing physical documents and migrating the existing content to the Company's Enterprise Content Management platform at a forecast cost of $0.3 million for 2014.

DRA recommends that the Commission reject the second and third IT initiatives proposed by PG&E to formalize meetings with suppliers and digitize physical documents. Given all the areas in this GRC that PG&E has requested digitizing physical documents as part of the migration to its new ECM platform, ratepayers are probably already duplicating funding for this process in this and earlier GRCs.

[1668] Ex. 30, p. 5-27.

[1669] Id., p. 5-28.

7.7.2 Capital Expenditures

PG&E's forecast for Supply Chain Sourcing Capital funding for IT initiatives is $10 million for 2014 and $4.8 million for 2015. Of these amounts, the Supplier Relationship Management 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 Enterprise Content Management, which PG&E forecast for 2014 at $1.6 million and $0.7 million in 2015.

PG&E does not forecast capital funding for implementing the Supplier Performance Management Technology program, which again reflects the fact that it primarily consists of PG&E's employees doing they work they were retained to do.

Consistent with DRA's recommendations under MWC JV in the preceding discussion, DRA recommends that the Commission approve the capital funding for the Supplier Management Technical/Functional Technology upgrade program, but reduce the authorized funding to 86 percent of the forecast to reflect actual results of such implementation in the 2011 GRC. This would reduce PG&E's forecast of $10 million to $7.3 million in 2014. DRA does not make any recommendations for the 2015 forecast as it is outside the current rate cycle, but DRA decision not to address the 2015 forecast at this time should not be viewed as an acceptance of that forecast or acquiescence with it[1670].

DRA recommends that the Commission deny approval of PG&E's forecast capital funding to integrate Supply Chain with Enterprise Content Management.

7.8 Real Estate

Shared Services and IT Real Estate consists of costs associated with managing PG&E's common utility plant buildings and yards, which include but are not limited to office buildings, service centers, shops, warehouses, construction and equipment yards, vehicle maintenance garages, customer service offices, Contact centers, data centers, and meetings and training facilities[1671].

[1670] Ex. 86 (DRA-18), p. 34.

[1671] Ex. 86 (DRA-18), p. 34; Ex. 30 (PG&E-7), p. 6-1.

PG&E's 2014 expense forecast for Corporate Real Estate is $32.6 million. PG&E acknowledges that recorded adjusted expense for 2011 was $12 million. Thus, the 2014 forecast is 172 percent more than 2011 recorded adjusted expense. PG&E claims that the primary reasons for this escalation are:

- Additional costs to maintain the Company's aging buildings and yards.
- Increased costs to complete building seismic safety upgrades.
- Additional costs to ensure compliance with the requirements of the ADA and Title 24 of the California Code and Regulations regarding accessibility at other Company buildings in addition to customer service offices.
- Expenditures to improve and provide additional offices space, rebuild outdated and inefficient service centers, and provide new buildings and yards to support PG&E's business needs.[1672]

None of the activities that PG&E now claims form the basis of the 172 percent escalation in costs from 2011 to 2014 are of recent origin. In fact, PG&E has been or should have been at work on all these activities for more than a decade.

Capital funding forecast for Corporate Real Estate in this rate cycles are: (1) $48.976 million for 2012, (2) $40.448 million for 2013 and $81.602 million for 2014. PG&E also forecast capital funding costs for 2015 and 2016, but DRA has not responded to forecasts that are outside this rate cycle.

7.8.1 Expense

Both the expense forecast and the capital forecasts are grouped into MWCs. The expense forecast MWCs for Real Estate are as follows:

(1) MWC BI (Maintain Building) - $24.903 million;

(2) MWC JH (Implement Real Estate Strategy) - $6.837 million; and

(3) MWC JV (Maintain IT Applications and Infrastructure) - $850,000.

7.8.1.1 MWC BI – Maintain Buildings

MWC BI comprises of the following programs: a) Base Building Program; b) Building Seismic Safety Program and c) ADA Compliance Program. PG&E's test year 2014 forecasts for

[1672] Ex. 30 (PG&E-7), p. 6-2.

Base Building Program is $14.803 million, $4.191 million for Building Seismic Safety Program and $5.909 million for ADA Compliance Program[1673]. In 2011, the recorded adjusted costs for these same programs were $3.376 million, $2.714 million and $2.823 million, respectively[1674].

As previously noted none of these programs are new and PG&E would have been working on these programs for at least a decade. Further, there is no particular change in circumstances that suggests that Corporate Real Estate is facing challenges that are far more than it faced in 2011. Therefore, DRA uses a five-year average of recoded data from 2007 to 2012, escalated to 2014, to forecast PG&E's 2014 MWC BI funding.

Further, PG&E has made these exaggerated claims in the past. In the 2011 GRC, the Commission authorized $26.5 million for Corporate Real Estate MWC BI "but [PG&E] reduced its budget for MWC BI by $18.2 million to $8.3 million" upon the grounds that it need to fund higher priority work in other parts of the Company[1675].

PG&E argues that DRA's recommendation failed to take into account its "127 pages of testimony and 964 pages of detailed workpapers to support its real estate forecasts". This argument is preposterous. DRA reviewed all of the evidence and found them unconvincing to support a cost escalation that is 172 percent above what PG&E requested and was approved for just two years previously. Much of the 127 pages of testimony that PG&E claims supports its real estate forecasts consist of descriptions of PG&E's facilities[1676] and a general statement that seismic project would make structural upgrades to the facility[1677].

e) Stockton Gas Plant

> This project will make structural upgrades to the Stockton Gas Plant building to meet the minimum PG&E design performance level of "Life Safety." The project will mitigate the seismic vulnerabilities of the building and also includes ADA improvements required by the local building department as part of the seismic upgrade permit. The forecast cost of the seismic upgrade at the Stockton Gas Plant is $1.2 million expense in 2012.

[1673] Ex. 30 (PG&E-7), p. 6-105.

[1674] Id,

[1675] Ex. 86 (PG&E-7), p. 38.

[1676] Ex 30 (PG&E-7), pp. 6-44 to 6-50; 6-66 to 6-95.

[1677] Id., p. 6-47.

> f) Livermore Office
>
> This project will make structural upgrades to the Livermore Office building to meet the minimum PG&E design performance level of "Life Safety." The Livermore Office also houses PG&E's Livermore customer service office (CSO). The project will mitigate the seismic vulnerabilities of the building and also includes ADA improvements required by the local building department as part of the seismic upgrade permit. The forecast cost of the seismic upgrade at the Stockton Gas Plant is $1.0 million expense in 2012.
>
> …
>
> h) Santa Maria Service Center
>
> This project will make structural upgrades to the Garage and Office/Warehouse buildings at the Santa Maria Service Center to meet the minimum PG&E design performance level of "Life Safety." The project will mitigate the seismic vulnerabilities of the building and also includes ADA improvements required by the local building department as part of the seismic upgrade permit. The forecast cost of the seismic upgrade at the Santa Maria Service Center is $1.2 million expense in 2012.[1678]

Except for the names of the facilities and in the case of Livermore the acknowledgement that the building also houses a CSO, all the descriptions are identical. It is unreasonable for PG&E' to argue that unless DRA has addressed each of these generalizations, DRA has not reviewed them or considered them in its analysis. DRA did not discuss these explanations separately and individually because they are simply not unconvincing and provide no evidence that deserves a response.

The main drivers for Corporate Real Estate activities are all events that increase gradually from year to year, and the Commission has recognized that it is appropriate to use recorded costs to estimate the test year forecast for such activities or events.

Notwithstanding this fact PG&E argues:

> Using recorded expenditures as the primary tool to forecast future real estate costs is inappropriate because the Company's real estate forecasts are bottom-up forecasts that identify the specific projects needed to maintain and improve the Company's aging buildings and yards, achieve building seismic safety, comply with ADA and other regulations, increase

[1678] Ex 30 (PG&E-7), pp. 6-47 to 6-48.

> the operating reliability of buildings that support critical business functions, and implement real estate solutions required to meet changing business needs.[1679]

The telling sentence in the foregoing argument is that "the Company's real estate costs forecasts are bottom-up forecasts", this means that the Company's real estate forecasts in the five years that DRA used for its average estimate were derived with the same bottom-up method that PG&E used in this 2014 rate case. Therefore, unless PG&E is claiming that the specific projects it needs to maintain and improve the Company's aging buildings and yards or comply with ADA and other regulations changes from year to year, the prior years recorded history forms the best basis for forecasting PG&E's future needs. As DRA noted, "maintenance should be a regular recurring event that can be planned and managed"[1680]. The delta between the recorded adjusted costs for MWC BI from year to year bears witness to this DRA testimony.

PG&E's protest of DRA's estimate for its Corporate Real Estate expense forecast continues:

> Q. 18 What will be the consequence of using recorded expenditures to forecast future real estate expenditures?
>
> A. 18 If the Commission were to accept DRA's position, it would be agreeing to a "self-fulfilling" premise that would never allow PG&E's real estate program expenditures to increase significantly above recorded expenditures. DRA's position that the Commission should not approve forecasts that are higher than the average of the Company's last five years of recorded expenditures is unreasonable for three reasons: (i) First, it ignores current and future conditions that differ from past conditions; (ii) Second, it does not consider the appropriateness of the specific activities and projects comprising each of PG&E's real estate program forecast; and (iii) Third, it requires PG&E to spend more than authorized in order to show the higher level of recorded expenditures necessary to gain DRA's support for future (General Rate Case) GRC forecasts.[1681]

The foregoing discussion of the consequences of using recorded expenditures to forecast future real estate expenditures is a good example of why DRA should not be expected to address every single narrative pretext in PG&E's testimony before making a forecast recommendation

[1679] Ex. 30 (PG&E-7), p. 6-7.

[1680] Ex. 86, p. 38.

[1681] Ex. 60 (PG&E-22), p. 6-9.

for PG&E's Corporate Real Estate. The discussion deliberately ignores the facts, which DRA addressed in its testimony. Consider for instance the argument that using recorded expenditures "requires PG&E to spend more than authorized in order to show the higher level of recorded expenditures necessary to gain DRA's support for future."[1682] DRA noted that in 2011 PG&E was authorized $27.5 million … but reduced its budget for MWC BI by $18.2 million to $8.3 million." DRA explained PG&E's rationale for the reduction as follows:

> PG&E says the "[d]ecrease reflects the decision not to pursue in 2011 the following projects in order to fund higher priority work in other parts of the Company: (i) 77 Beal St./One Market Plaza project; (ii) Customer Office Refurbishment Project; (iii) certain non-mandatory ADA surveys; and (iv) certain Base Building maintenance projects (e.g., roofing repairs, HVAC repairs, carpet replacement, interior painting)."[1683]

These facts reflect that the rationale which supports using recorded cost averaging is that which requires PG&E to spend what it was authorized rather than more than it was authorized in order to show a higher level of recorded expenditure. The audacity with which PG&E makes this claim despite evidence to the contrary reflects the PG&E's attitude towards much of its recommendations for Shared Services and IT.

PG&E also argues that using recorded cost averaging "does not consider the appropriateness of the specific activities and projects comprising each of PG&E's real estate program forecasts."[1684] Consider PG&E's rationale for transferring funds from MWC BI to other projects outside in 2011. Among the projects deferred were 77 Beale Street/One Market Plaza project and certain non-mandatory ADA surveys. These same projects occupy more than 10 pages of discussions in this GRC[1685]. Here again the specific activities and projects comprising the real estate program forecasts, show that they do not support the 172 percent escalation of costs, when only two years ago they were considered lower priority work.

[1682] Id.

[1683] Exh. 86, DRA-18, p.38, citing *Pacific Gas and Electric Company's August 3, 2011 Budget Report in Compliance with California Public Utilities Commission Decision 11-05-018, p.8.6.*

[1684] Ex. 30 (PG&E-7), p. 6-9.

[1685] Id., 77 Beal St./ One Market Plaza: Page 6-95 to 6-100, p.6-25; ADA Compliance: Page 6-55 to 6-63, 6:25.

When one reviews each of the programs separately, PG&E's cases looks even worse. Discussing the ADA initiative for instance, PG&E stated:

> 1) Initiative to Enhance ADA Compliance at Company Buildings
>
> CRE Enhanced ADA Compliance Program will assure ADA Title 1 (employee accessibility) and Title 3 (public accessibility) to all CRE-managed buildings. When used in this chapter, "ADA compliance" is intended to include Title 24 compliance where appropriate.
>
> This initiative includes the cost of performing detailed ADA accessibility assessments at approximately 190 CRE-managed buildings. These surveys will establish updated accessibility condition information for each building, identify recommended accessibility improvements with the assistance of external ADA experts, and implement these recommendations.
>
> Following enactment of the ADA in 1992, CRE completed "readily achievable barrier removal" projects for ADA Title 1 and Title 3 compliance in its buildings. However, as noted above, those original efforts may be outdated and may no longer meet current ADA requirements.[1686]

First note that CRE completed ADA compliance on all its buildings following enactment in 1992, and now only wants to review its compliance status because "those original efforts may be outdated and may no longer meet current ADA requirements", to which one might well say: "On the other hand, they may still be in compliance." The point is that without knowing whether it is actually out of compliance, PG&E escalated its ADA forecast by more than one hundred percent on pure speculation. The CPUC has had the same handicap ramp up the front of the building, the same size rest rooms, the same sitting spaces and other elements that usually comprise ADA compliance requirements for more than 10 years. Assuming they were in compliance at the time they were built and have not fallen out of compliance, how much should the CPUC spend in reviewing the likelihood that the facilities are not in compliance. It is important to note that PG&E seeks to conduct these surveys for all of its CRE managed buildings. It is unnecessary make work that would again result in funds being transferred to other areas that the Company identifies as higher-priority work.

[1686] Ex. 30 (PG&E-7), pp. 6-56 to 6-57.

7.8.1.2 MWC JH – Implement Real Estate Strategy

PG&E's Real Estate Strategy consists of the Real Estate Planning and Transaction program and the Real Estate Solutions program expensed in MWC JH. PG&E maintains that its Real Estate Planning and Transactions program will improve the management of vacant properties and reduce future costs of underutilized and surplus real estate[1687]. Real Estate Solutions program will form the basis for CRE to refurbish, relocate, replace and close offices and service centers to correct condition deficiencies, improve functionality, implement workplace improvement and meet business needs[1688].

PG&E's 2014 expense forecast for Real Estate Planning and Transactions program is $5 million dollars and for Real Estate Solutions is $2 million. In 2011, the recorded expense cost for Real Estate Planning and Transactions was $3.1 million and for Real Estate Solutions was $0[1689]. The total forecast funding for MWC JH for 2014 is $6.8 million to be exact and 76 percent higher than the 2012 actual recorded expense[1690]. In fact, PG&E's 2014 recorded expense forecast for MWC JH is higher than it has ever been in the last five years during which time it only exceeded $4 million once[1691].

DRA used a five year average of recorded expense, escalated to 2014, $4.04 million as the appropriate test year forecast for MWC JH[1692].

7.8.1.3 MWC JV – Maintain IT Applications and Infrastructure

MWC JV is the IT Applications and Infrastructure component of CRE's Base Building Program and the Real Estate Planning and Transaction Program. PG&E forecast $0.85 million for this program in test year 2014, with $0.65 million forecast for the Base Building Program and $0.2 million for the Real Estate Planning and Transactions program.

[1687] Id.. p. 6-25.

[1688] Id.

[1689] Id., p.6-102; Ex. 86 (DRA-7), pp. 39 – 40.

[1690] Ex. 86 (DRA-7), p. 40.

[1691] Id., See Table 18-35 showing recorded expense for MWC JH from 2007 to 2012 as $3.976 million, $4.586 million, $3.191 million, $3.250 million, $3.130 million, $3.887 million respectively.

[1692] Id., p. 35.

DRA opposes rate payer funding for MWC JV because PG&E was funded for a similar Real Estate Planning and Transactions program initiative in 2011 but PG&E did not implement the initiative. Regarding the Base Building Program initiative, DRA writes:

> While PG&E states that the total revenue requirement provided by the 2011 GRC decision was less than PG&E's 2011 GRC forecast and therefore insufficient to support all of the work forecast in PG&E's 2011 GRC testimony, PG&E's March 2012 Budget Report shows that PG&E had $608,000 left in its 2011 budget. … Ratepayers should not be required to pay twice.[1693]

7.8.1.4 MWC 22 (Maintain Building)

PG&E forecasts the capital cost for its Base Building Program and Building Seismic Safety Program in MWC 22. The Base Building Program capital costs consist of replacement costs that PG&E claims would "extend the life of building components, correct building component deficiencies, improve equipment-operating efficiencies, replace failed or functionally obsolete building components, and increase the operating reliability of PG&E's buildings and yards."[1694]

The Building Seismic Safety Program aims to improve the seismic performance of Company buildings located in areas predicted to experience a higher risk of strong seismic activity. PG&E has completed seismic safety work in 76 of its buildings and forecasts an additional 16 buildings to be completed in this rate cycle.[1695]

PG&E's 2014 capital expenditure forecast for its Base Building Program is $44.125 million and for its Building Seismic Safety Program is $1.549 million. In 2012 PG&E recorded costs for MWC 22 was $46.733 million.

DRA accepts PG&E's 2012 recorded costs for MWC 22 but recommends that the Commission use a five-year average forecasting methodology to set PG&E's test year 2014 costs.

The Commission should not rely solely on PG&E's forecast as the timing and scope of the projects included in its request are at the discretion of PG&E.

[1693] Ex. 86 (DRA-7), p. 41.

[1694] Ex. 30 (PG&E-7), p. 6-26.

[1695] Id., p. 6-41 to 6-42.

> PG&E's August 3, 2011 Budget Report Illustrates that the ratepayer funds provided in the 2011 GRC for MWC 22 (previously MWC 78 and MWC 88) have been used elsewhere. In that August 3, 2011 Budget Report, the MWC 22/23 (previously MWC 78) budget was decreased by $15.4 million from the GRC imputed amount of $65.4 million to $50 million. Also, MWC 22 (previously MWC 88) was decreased by $5.2 million from GRC imputed amount of $5.7 million to $0.5 million. …
>
> …DRA simply highlights the fact that … ratepayers should not pay based solely on what PG&E management wants, but rather based on what PG&E has delivered.[1696]

7.8.1.5 MWC 23 (Implement Real Estate Strategy)

MWC 23 represents capital cost for the Real Estate Strategy Solutions Program. PG&E's 2014 capital forecast for MWC 23 is $35.4 million. This 2014 forecast amount exceeds anything that has been recorded MWC 23 or its predecessor accounts in the past six years. "In fact, PG&E's 2014 request for MWC 23 exceeds what PG&E has spent in this MWC for the past six years combined."[1697] Recorded cost for Real Estate Solution Capital in 2011 was $6.4 million.

DRA recommends that the Commission authorize $10 million for MWC 23 test year 2014 expenditure. "DRA's forecast is based on its recommendation that one project [in the Program] be rejected and that the remaining balance be normalized over three years."[1698]

One remarkable aspect of PG&E's escalation of its forecast for MWC 23 is the degree to which the work is both discretionary and cosmetic. Describing what it saw as the future state of Real Estate Solutions Program, PG&E stated:

> CRE forecast for the Real Estate Solutions Program includes expenditures to refurbish or replace office and service center buildings to correct condition deficiencies, improve functionality, implement workplace improvements, and meet current business needs. CRE's forecast for this program also includes expenditures to provide additional office space where needed, refurbish floors at 77 Beale Street and improve the operating reliability of the Fairfield data center.[1699]

[1696] Ex. 86 (DRA-7), p. 43.

[1697] Id., p. 45.

[1698] Id., p.45 illustrating the removal of the program and normalization of the remaining costs as follows: ($35.378 - $5,233)/3 + 10.048.

[1699] Ex. 86 (DRA-18), p. 6-66.

DRA fails to understand why PG&E would oppose normalizing the cost of refurbishing floors and creating additional office space rather than creating a rate shock in a GRC that PG&E is planning the most ambitious optimization and improvement of every single asset it owns regardless of the need or benefit of doing so in one rate cycle.

The one project that DRA is opposed to including in MWC 23 is the plan to provide a dedicated 12kV power feed from the Cordelia Substation, located approximately six miles away, to the Fairfield Data Center. The project is essentially more of a question of convenience rather than need. The Fairfield Data Center has been superseded by PG&E's new Sacramento Data Center, which 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. In addition, CAISO maintains visibility with the same resources that the Data Centers are monitoring, and 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.

> Several utility power disruptions to the Fairfield Data Center have occurred since December 2011. While most disruptions were momentary, one outage was over 22 minutes in duration. Secondary systems such as uninterruptible power systems, batteries and standby generators are in place to support critical operations when utility power disruptions occur. However, any utility power disruption carries the potential of catastrophic data center failure if any of the secondary systems or system components fails.[1700]

In addition to the fact that there are cheaper alternatives to incurring this $5 million for a 12kV already available to the data center, PG&E upgraded the Fairfield Data Center in the period leading up to the 2011 rate cycle and did not see the need or urgency to add the dedicated 12kV line. Therefore, as the "Fairfield Data Center … already has secondary systems, DRA recommends not funding a dedicated power feed" to the Center[1701].

7.8.2 Capital Expenditures

Capital costs under MWC 2F are for Base Building Program and the Real Estate Planning and Transaction Program.

[1700] Ex. 30 (PG&E-7), p. 6-102.

[1701] Id., p. 45.

1.17.2.4 MWC 2F – Build IT Applications and Infrastructure

PG&E's 2014 forecast for MWC 2F is $0.350 million under the Base Building Program and $0.2 million for Real Estate Planning and Transmission program. The capital expenditure under the Real Estate Planning and Transmission Program is primarily to integrate CRE's stand-alone occupancy planning database with PG&E's information management systems.

PG&E identified both the Base Building Program and the Real Estate Planning and transaction Program in its 2011 GRC but claimed that total revenue requirement the Commission authorized for the 2011 GRC was insufficient to support all of the work forecast in PG&E's 2011 GRC testimony. By this rationale, unless the Commission approves the exact amount that PG&E requested in its GRC applications, PG&E has the discretion to refrain from implementing programs sought in that GRC and request the same programs again in subsequent GRCs ad infinitum.

DRA opposes ratepayer funding for Base Building Program and the Real Estate Planning and Transaction Program. PG&E has not spent its 2011 budgeted expense amounts for IT and should not be approved for more ratepayer funds for programs it has already presented to the Commission and received authorized funding in prior rate cases.

Environmental Program consists of the forecasts for Administrative and General (A&G) expenses, Operations and Maintenance expenses and Capital expenditures necessary to manage PG&E's Environmental Organization and implements its programs and policy. These expenditures include the costs for complying with environmental laws and regulations, managing PG&E's expansive land resources, protecting sensitive species and natural resources and remediating environmental contamination from historic operations, among others[1702]. PG&E claims that the workload for its environmental organization increase as its investment in infrastructure upgrades increase.

There are three categories of Environmental costs[1703]:

(1) A&G expenses for the organizations that charge to A&G;

(2) O&M expenses and capital expenditures within the Environmental Major Work Categories (MWC), and

[1702] Id., p. 7-1.

[1703] Id., p. 7-3

(3) Costs embedded in capital and expense projects, activities, and programs managed by other departments.

Only the Categories for A&G expenses and O&M and capital expenditures are forecast under this section on Environmental Program. Costs embedded in projects and programs managed by other departments are not part of Shared Services and IT and are discussed in under other lines of business.

7.8.3 Expense

The major work categories for expenses under the Environmental Program are:

(1) MWC AK – Manage Environmental Operations;

(2) MWC AY – Habitat and Species Protection;

(3) MWC CR – Manage Waste Disposal and Transportation;

(4) MWC ES – Environmental Projects and Initiatives;

(5) MWC FA – Special A&G/Other Costs;

(6) MWC JE – Manage Land Services,

(7) MWC JK – Manage Environmental Remediation;

(8) MWC JV – Maintain IT Applications and Infrastructure;

DRA does not oppose PG&E's forecast of expenses for MWC AY, MWC CR, MWC FA, and MWC JK, therefore will not be discussing them in this opening brief.

The major work categories for capital under the Environmental Program Section are:

(1) MWC 5 – Land and Environmental Management Tools and Equipment

(2) MWC 12 – Environmental Operations

(3) MWC 2F – Build IT Applications and Infrastructure.

DRA does not oppose PG&E's capital forecast for MWC 5, and therefore will not discuss it in this opening brief.

7.8.3.1 Operations and Maintenance Expense

MWC AK – Environmental Operations:

Environmental Operations are costs for routine environmental work by PG&E, including day-to-day work costs that are part of each facilities normal operation, such as labor costs of

environmental professionals and facility personnel who perform environmental compliance tasks, as well as materials, contracts and fees[1704].

PG&E forecast $16.1 million for test year 2014 MWC AK expenses. The recorded costs for 2011 was $9.7 million. DRA recommends $11.1 million for MWC AK based on a five year average of recorded costs escalated to 2014 dollars. DRA reasoned that because the main driver for the cost escalation from 2011 to 2014 is $5.3 million Air Resources Board (ARB) annual Cost of Implementation Fee, which is recoverable from end-use gas transportation and bundled electric generation customers, ratepayer should not be burdened with that cost.

> PG&E states that the main driver in the 2014 increase is $5.3 million in MWC AK for the Air Resources Board (ARB) annual Cost of Implementation Fee legally mandated by Assembly Bill (AB) 32 which is recoverable from end-use gas transportation and bundled electric generation customers. PG&E states that the remaining increase is necessary to pay increasing permit fees to regulatory agencies and for increases in labor and contract costs.
>
> …
>
> Subsumed in that [DRA] forecast is DRA's recommendation that the $5.3 million in the ARB annual Cost of Implementation Fee should not be included in PG&E's revenue requirement since this is recoverable from end-use gas transportation and bundled electric generation customers.[1705]

In its rebuttal to DRA's testimony, PG&E "…accepts the forecast in this case [exclusion of $5.3 million in ARB fees] because the Commission has ruled that the ARB implementation costs are recoverable in other proceedings."[1706]

MWC ES – Environmental Projects and Initiatives:

> Environmental Project and Initiatives includes costs associated with repairing, replacing and upgrading equipment to comply with environmental regulations. Relevant projects include retrofits and repairs of various hazardous waste storage tanks, facilities, and storm water collection systems at facilities, repairs to vehicles washing systems at facilities, and miscellaneous compliance-driven expense projects[1707].

[1704] Id., p. 7-21.

[1705] Ex. 86 (DRA-18), p. 49.

[1706] PG&E rebuttal accepts this. PG&E-22, page 7-11, line 30 continuing to page 7-12, line 2.

[1707] Ex. 30 (PG&E-7), p. 7-26.

PG&E's 2014 expense forecasts for MWC ES for test year 2014 is $0.9 million. The recorded cost for 2011 was $0.5. However, PG&E claims that it "anticipates" an "increase in retrofits and repairs of fuel and hazardous waste storage tanks required by regulation and for SPCC Plan modifications at distribution substations.[1708]" PG&E does not explain why it "anticipates" this increase in retrofits and specifically "at distribution substations", which give it a touch of the mystical. However, the proof necessary to support a rate increase should be more than a utility's claim of "anticipation". As the record in this GRC clearly shows PG&E appears to "anticipate" an increase in everything that would increase its forecasted expense and capital costs, including MWC ES.

DRA recommends a forecast of $0.882 million.

> DRA believes its forecast of $0.882 million is sufficient to fund these projects and initiatives, and notes that in its testimony, PG&E forecasted most of the increase in 2012, yet the actual recorded 2012 expense was $177,000 less than PG&E had forecasted for that year.[1709]

MWC JE – Manage Land Services:

> PG&E manages a variety of land rights support activities under MWC JE, including maintenance of the Land Rights Library, coordination with state Board of Equalization, staff training and maintenance of guidance documents and management of properties leased or licensed by others. The land management activities in this category include sustainable forest management and fuel (i.e., timber) reduction projects, annual timber inventory, seed storage and conifer seed growing.

PG&E also seeks to include funding for $1.1 million initiative to develop a land stewardship management program under MWC JE and $0.2 million to support other land management activities and labor escalation. PG&E's total expense forecast for MWC JE is $3.3 million compared with $2 million recorded cost in 2011.

PG&E's bankruptcy in 2003 required PG&E to establish a Land Stewardship Council where PG&E's shareholders would sponsor $10 million dollars by giving $1 million annually for the stewardship management program much like PG&E has described in MWC JE.

[1708] Id.

[1709] Ex. 86 (DRA-18), p. 51.

Q. What's the role of the stewardship council, then? I'm trying to understand after -- well, let me put it this way simply: Can you tell me what the role of the stewardship council is with respect to these parcels of land?

A. Yeah. This stewardship council was created as a result of a bankruptcy proceeding. And I think generally the best way to describe what their responsibility is governance over the overseeing of the development of these land conservation plans. They are an independent nonprofit organization, and they act as an advisory body to provide guidance and governance over what to do with the disposition of these lands.[1710]

When asked the difference between the land conservation council activities that was established in PG&E's bankruptcy and the stewardship activities that PG&E is proposing under MWC JE, PG&E's witness could not articulate any difference.

Q. Are you familiar with the Land Conservation Council Program that PG&E set up at the time of its bankruptcy?

A. The Land Conservation Commitment, yes, I am.

Q. Is this the same type of stewardship program you're talking about here?

A. It's part of it in that as part of the Land Conservation Commitment, there will be conservation easements placed on many of PG&E's 140,000 acres of watershed lands. And so part of what's embedded in the 1.1 million is funding to manage those lands consistent with the new conservation easements. But, as the response in Answer 11 lays out, there are other activities that are not necessarily directly related to the Land Conservation Commitment. It's [sic] activities that we do now, but we want to do more proactively across particularly the non-watershed lands.[1711]

It is a disturbing coincidence that PG&E $1.1 million forecast for this stewardship council is exactly the same amount that PG&E's shareholders were required to pay under the 2003 bankruptcy plus what would amount to a 10 percent interest for payments of $10 million dollars made over ten years.

[1710] Tr. Vol. 20, p.2277.

[1711] Tr. Vol. 23, pp. 2896 – 2897

DRA recommends $2.1 million forecast for MWC JE. DRA's forecast was derived from a five-year average of recorded costs escalated to 2014 dollars. DRA does not support ratepayer funding for PG&E's Land Stewardship Program. Even if PG&E could articulate the difference between its Land Stewardship Program and the Land Conservation Program that its shareholders were supposed to be responsible for, "PG&E must already inspect and manage its properties. And while PG&E states that "active management cost less by reducing illegal dumping, trespass, encroachments, or other illegal third party activities on company lands"[1712] PG&E's proposal does not reflect these savings. DRA does not see sufficient benefit for spending $1.1 million on this program."[1713]

MWC JV – Maintain IT Application and Infrastructure:

PG&E forecasts $4.4 million for MWC JV expense to support several initiatives that sound like they are only remotely connected to maintaining IT application and infrastructure. These initiatives include: "Enhancing PG&E's Environmental, Health, and Safety Management System, which include deploying mobile technologies; Improving environmental review and permitting of construction projects; Expanding programmatic and regional permits, Enhancing electronic document management; and Upgrading the Building and Land Management System."[1714] Of course, PG&E projects these activities to increase over 2011 costs.

The recorded adjusted cost for MWC JV in 2011 was $0.5 million[1715].

DRA recommends $1.1 million in 2014 expenses for MWC JV, based on the further recommendation that two projects proposed by PG&E under this MWC should be denied.

> DRA opposes ratepayer funding for two projects proposed by PG&E as there are minimal benefits to ratepayers. PG&E's proposal to spend $2.8 million in expense in 2014 (and $3.32 million in capital) for Enhancing PG&E's Environmental, Health, and Safety Management System seems excessive to achieve cost avoidance in data entry and reporting efficiencies, decreased costs of compliance, software purchases, licenses and hosting fees.[1716] In addition, PG&E is not able to quantify these

[1712] Ex. 34 (PG&E- 7), p. WP 07-09, p. WP 7-46.

[1713] Ex. 86 (DRA-18), p. 54.

[1714] Id., p. 55; Ex. 30 (PG&E-7), p. 7-26.

[1715] Id.

[1716] Ex. 34 (PG&E-7), p. WP 07-09, p. WP 7-51.

> supposed cost avoidances. Similarly, PG&E's proposal to spend $0.5 million in expense in 2014 (and $0.65 million in capital) for enhancing electronic document management also appears excessive to achieve non-cost benefits. PG&E did not include any cost benefits for this project.[1717]

7.8.3.2 Administrative and General (A&G) Expense

PG&E forecast A&G expenses for Shared Services IT under MWC FA and JK. DRA does not oppose PG&E's forecast of expenses for MWC AY, MWC CR, MWC FA, and MWC JK, therefore will not be discussing them in this opening brief.

7.9 Information Technology Costs

Information Technology Costs are for services provided by PG&E's IT organizations under the following three portfolios of initiatives: (1) Baseline Operations Portfolio, (2) Technology Reliability Portfolio and (3) Business Technology Project Portfolio.

Baseline Operations are for ongoing maintenance and operations of PG&E's existing systems and infrastructure. PG&E maintains that Baseline Operations must remain dynamic and expand to support new functions in order to accommodate new projects that are being deployed by the Company.

Technology Reliability Portfolio "represents PG&E's physical asset replacement initiatives and break-replace services that are required to maintain the current operational and reliability targets for all computing and network systems."[1718] The Reliability Portfolio also encompasses enterprise-wide information technology projects, enabling critical cybersecurity functionality and internal IT projects targeted at improving services that IT provides to the Company[1719].

Business Technology Project Portfolio enable and support PG&E's lines of business in providing safe and reliable service to PG&E's customers and support the full range of PG&E's business processes.

[1717] Ex. 86 (DRA-18), p. 56.

[1718] Ex. 35 (PG&E-8), p. 8-2.

[1719] Id., p. 8-2 to 8-3.

PG&E forecasts the expense cost for these three portfolios in MWC JV – Maintain Applications and Infrastructure, and the capital cost in MWC 2F – Build Application and Infrastructure.

7.9.1 Expense

PG&E currently lists all IT expenses used by the IT Organization under MWC JV. These expenses include costs for all three portfolios covering ongoing maintenance, operations and repair for PG&E applications, systems and infrastructure.

7.9.1.1 MWC JV – Maintain Applications and Infrastructure

PG&E forecasts $261.603 million for MWC JV. The 2011 recorded cost was $216.959 million. PG&E claims that the key drivers for the increased cost in MWC JV are an increase in contract costs of approximately $39.4 million, increased labor costs of approximately $2.6 million, and increased cost of approximately $5.7 million in 2014 for 42 additional employees."[1720]

DRA recommends $231.8 million for MWC JV. DRA derived its forecast by trending out PG&E's 2014 costs for its Baseline Portfolio from 2008 to 2012. Although DRA did not have the 2012 Baseline Portfolio recorded costs at the time DRA prepared its testimony, DRA "used PG&E's 2012 budgeted Baseline Portfolio to total MWC JV and applied that percentage (96%) to 2012 recorded MWC JV cost of $216 million"[1721]. This trending resulted in a $221 million forecast for the Baseline Portfolio. he remaining $11 million in DRA's forecast was derived "by using a five year average of PG&E's Lifecycle functional area, accepting PG&E's 2014 forecast for technology reliability project functional area, and rejecting PG&E's 2014 forecast for the continuous improvement functional area".

Regarding the functional areas and DRA's rejection of the continuous improvement functional area, DRA reasoned as follows:

> The three functional areas that make up the Technology Reliability Portfolio are: lifecycle activities; technology reliability projects; and, continuous improvement initiatives. Lifecycle activities are the replacement and upgrade of PG&E's billion dollar plus IT asset base.

[1720] Id., p.62, citing Ex. 30, p. 8-35.

[1721] Ex. 86, p. 62.

Technology reliability projects are large-scale information technology projects originating within the IT organization. Continuous improvement initiatives include costs for initiatives specifically designed to improve IT services and reduce costs for IT services.

…

DRA rejects PG&E's 2014 forecast for the continuous improvement functional areas as it includes two projects that DRA opposes. The two projects are Record Management Archival project to design and implement a records management system built around PG&E's Documentum tool, and Service Management project that PG&E states will reduce the frequency and duration of IT systems and application outages and provide IT better visibility into issues in its environment.

DRA opposes the Record Management Archival project as it places the cart before the horse. As PG&E provides in its testimony "PG&E is in the process of building the Documentum tool. When the work forecast in the 2011 GRC is complete, Documentum will provide some of the capabilities that PG&E needs for its Records Management Archival program. However, it is not robust enough to provide all of the required functionality so PG&E will need to add additional tools and capabilities forecast in this rate case."[1722] DRA opposes ratepayer funding until PG&E has demonstrated that the 2011 GRC funding it has received for the enterprise-wide data archival and records management program is operational.

DRA is also opposed to ratepayer funding for PG&E's Service Management project as continual improvement should be implicit in PG&E management activities. Ratepayers should not have to fund specific projects to gain improvements.

As discussed in Exhibit DRA-13 (Customer Care Costs), DRA rejects PG&E's forecasted Smart Meter Opt-Out Program costs. DRA removed $270 thousand in associated cost from MWC JV from this section. Taken together, DRA recommends $231.8 million in MWC JV for 2014.[1723]

7.9.2 Capital Expenditures

PG&E forecasts costs to design, develop and enhance applications, systems and infrastructure technology solutions under MWC 2F. In the past PG&E recorded these costs in

[1722] Ex. 30 (PG&E-7), p. 8-58.

[1723] Ex. 86 (DRA-18), pp. 61 – 63.

eight separate major work categories of capital expenditure. PG&E's 2014 forecast for MWC 2F is $212.3 million, a 30 percent increase over actual 2012 recorded costs.

> PG&E forecasts capital expenditures of $105.7 million in 2014 for Lifecycle functional area, $83.3 million in 2014 in Technology Reliability functional area, and $23.4 million in 2014 for its Continuous Improvement functional area. In sum, PG&E is forecasting total capital expenditures in MWC 2F of $212.3 million in 2014. This is a 30% increase from PG&E's actual 2012 recorded capital cost.[1724]

DRA recommends $161.3 million for MWC 2F, by normalizing one project in the Technology Reliability functional area and adjusting the other project to 86 percent of the forecast.

> DRA reduced PG&E's Identify and Access Management project to 86% of forecast, and normalized PG&E's Telecommunication Network Enhancement project. The adjustment is based on PG&E's actual to 2011 GRC forecast of IT projects that used the concept cost estimating tool. This is discussed further below. DRA normalized PG&E's Telecommunication Network Enhancement project as PG&E states that the core and edge telecommunication networks, as currently constructed, will meet the projected demand and capacity for the next three years. After adjusting for these two projects, DRA's recommendation for the Technology Reliability functional area is $55.6 million for 2014.[1725]

The resulting $55.6 million from DRA's adjustment to the Technology Reliability functional are added to PG&E's forecast of $105.7 million for Lifecycle forecast constitutes DRA's $171.3 million recommendation for MWC 2F.

Consistent with its recommendations throughout the review and analysis of Shared Services and IT functions, DRA rejected two projects in the Continuous Improvement functional area.

> In the Continuous Improvement functional area, DRA rejects both projects and recommends $0 dollars in 2014. The two projects in the Continuous Improvement functional area are Records Management Archival and Service Management projects. As discussed in the related expense section above, DRA objects to ratepayer funding until PG&E has demonstrated that the 2011 GRC funding it has received for the enterprise-wide data

[1724] Id., citing Ex. 30 (PG&E-7), p.8-63, (212,321 – 163,444)/163,444 = 29.90%

[1725] Ex. 86, pp. 65 – 66.

> archival and records management program is operational. There is no ratepayer benefit to be gained from funding additional tools and capabilities if the enterprise-wide archival is not operational. Additionally, DRA questions why PG&E continued the 2011 GRC funded archival project knowing that it did not offer all the functionality that PG&E required.
>
> Also, DRA is opposed to ratepayer funding for PG&E's Service Management project as continual improvement should be implicit in all of PG&E's management activities. DRA is also opposed to PG&E's forecasted Smart Meter Opt-Out Program Cost as discussed in Exhibit DRA-13. In sum, DRA recommends $161.3 million for MWC 2F in 2014.[1726]

7.10 Information Technology Cybersecurity

7.11 Records Management

Throughout DRA's review of Shared Services and IT capital forecasts, in every section where PG&E made a forecast using its "Concept Cost Estimating Tool", DRA recommended that the Commission adjust the PG&E's request to 86 percent of the forecast. DRA made these recommendations based on its review of PG&E's actual 2011 GRC forecast of IT projects that used the concept cost estimating tool.

In this section, we reproduce the reasoning from DRA's report that supports this cost estimating policy or methodology for PG&E's business technology IT forecasts:

> PG&E uses its "Concept Cost Estimating Tool" to forecast costs for proposed IT application development projects. According to PG&E, a more detailed cost estimate is prepared when the project requirements, strategy and technology solutions are more fully developed, just before the commencement of the project.[1727]
>
> PG&E states that the concept estimating tool applies standard industry practices for IT project estimating. PG&E has been using the concept estimating tool since 2008 as the basis for generating the initial cost estimate for application development projects. The cost forecast for the Business Technology IT projects presented by the LOBs in PG&E's 2014 GRC were developed using the IT concept cost estimating tool. In the 2011 GRC, PG&E introduced the concept estimating tool as part of its

[1726] Ex. 86 (DRA-18), p. 66.

[1727] Ex. PG&E-7, p. 8-66.

process to estimate the costs of line of business technology application development projects. Since that time, the tool has remained largely the same; however, some adjustments and refinements have been made to the tool to improve its accuracy.[1728]

PG&E states that the concept cost estimating tool is a computer based tool built in Excel and takes the form of a workbook containing several tabs. The tool includes a series of checklists and templates that the user completes to ensure all types of costs are included. The tool was developed by PG&E and is based on the standard industry approach for estimating IT application development costs early in the project lifecycle. To complete the checklist and generate the initial concept estimate, the IT project team works with the line of business to outline the business need for the IT project, understand the business requirements, outline the IT project benefits, and develop the timing for delivering the project. Using the information collected from the line of business, the IT project team completes the concept cost estimating checklist.[1729]

Built into the concept cost estimating tool are a series of assumptions that the model uses, along with the information the user inputs into the tool, to calculate the various costs that roll up to the initial project forecast. The assumptions include percentage splits between capital and expense amounts, allocations of time across the different project stages (i.e., project development, testing, training, etc.) and burden amounts. Percentage splits between capital and expense are based on advice from PG&E's Capital Accounting organization for application development projects. Time allocations among the project stages are based on industry benchmark analytics. Percentages for burdens are based on information provided to IT by PG&E's Finance organization. Standard cost information and assumptions built into the model, such as labor rates and burden rates, are regularly updated by the IT team responsible for the concept cost estimating tool. Updates and changes are tracked in the Usage and Version Control tab included with the model.[1730]

Using the concept estimating tool requires the user to answer questions, complete checklists and fill-in templates. The checklists and templates are designed to ensure that the IT project team and line of business sponsors have identified and considered all of the required project components such

[1728] Ex. PG&E-7, p. 8-66.

[1729] Ex. PG&E-7, p. 8-66.

[1730] Ex. 30 (PG&E-7), p. 8-67.

as security needs, infrastructure requirements, O&M costs, and staffing needs.[1731]

After completing the checklists and templates and generating a project forecast range, the IT project team evaluates the different program elements and determines the project cost forecast within the forecast range generated by the model. The IT team relies on its professional judgment and experience with application development projects in this evaluation, taking into consideration several key elements such as: PG&E's confidence level relative to undertaking the IT program; PG&E's history and familiarity with similar types of IT programs; the program complexity, including elements such as interfaces with other PG&E programs, number of user and user groups impacted, data exchanges outside of PG&E and changes to PG&E's infrastructure; and the certainty of the line of business requirements for the program at the time the forecast is developed. The result of the evaluation is the forecast project cost that is included in the GRC request.[1732]

PG&E states that most of the IT application development project forecasts included in the GRC are generated by the concept cost estimating tool because most of the projects have not proceeded past the initial stages of the IT project lifecycle as defined by the IT Methodology (discussed in Section C(2)(a) in PG&E-7).[1733]

The Commission should not base PG&E's IT project revenue requirement on PG&E's concept cost estimating tool. As PG&E states in its testimony "the concept cost estimate is the first cost estimate generated for a project and it is necessarily presented as a range of costs, because business requirements and technology solutions are still in the initial planning stage."[1734] Additionally, the funding requested for the IT projects in the GRC are not strictly based on the cost estimating tool. As PG&E provides in its testimony and data response, "the forecast amounts included in the GRC for IT application development projects are based on a combination of the output of the concept estimating tool and PG&E's best professional judgment."[1735] Additionally, unlike the revenue requirement that PG&E will receive for the IT projects, there are no certainties that the IT projects that PG&E requests funding for in this GRC will actually be completed.

[1731] Id.

[1732] Id., p. 8-70.

[1733] Id.

[1734] Id., p. 8-71.

[1735] PG&E data response _DR_DRA_239-Q01.

> As such, DRA recommends that the Commission limit ratepayer funding of IT projects to 86% of PG&E's requested costs for those projects not otherwise opposed by DRA. DRA has determined that for all IT projects forecast by PG&E in its 2011 GRC which relied on the concept cost estimating tool, PG&E only spent 86% of its forecast based on the actual funds expended by PG&E. DRA believes it is appropriate to assume the same level of IT under-spending in this GRC for proposed IT costs in which PG&E relied on the concept cost estimating tool.[1736]

7.12 Supply Chain – Materials and Logistics and Planning

PG&E's Supply Chain – Materials Logistic and Planning (MLP) maintains inventory of supplies and provides materials and services to other PG&E line of business (LOB) partners, including providing the necessary materials and services to support "PG&E's ongoing maintenance and construction activities".[1737] Warehousing, transportation logistics, supplier quality assurance, materials field services (MFS), inventory planning, inventory control and management, investment recovery and emergency response are all services MLP provides to the Company[1738].

7.12.1 Expense

The major work categories under MLP expense forecasts are MWC BI (Maintain Buildings) and MWC JV (Maintain IT Applications and Infrastructure). PG&E forecast $1.3 million for test year 2014 MLP expense and states that "[r]ecorded expense for MLP was $0 for MWC BI [in 2011] and $1.2 million [for MWC JV] in 2011". PG&E also explains that the 2011 recorded expenditures and the 2014 forecast expenditures for MLP are one-time projects that do not lend themselves to year-to-year comparisons[1739]. However, they do lend themselves to cost-benefit analysis but PG&E has not conducted any.

MLP capital expenditure forecast consists of four numbered MWCs – 05 (Tools and Equipment), 21 (Miscellaneous Capital), 22 (Maintain Buildings) and 2F (Build IT Applications and Infrastructure). PG&E forecast $1.4 million for MLP capital in 2012, $0.8 million in 2013 and $7.8 million for 2014. Although PG&E also forecast MLP capital expenditure for 2015 and

[1736] Ex. 86 (DRA-18), pp. 66 – 69.

[1737] Ex. 30 (PG&E-7), p. 4-1.

[1738] Ex. 86 (DRA-18), p. 24.

[1739] Ex. 30 (PG&E-7), p. 4-1.

2016, DRA did not address the forecast for those years as they fall outside this test-year GRC time-frame. DRA's decision not to address the 2015 and 2016 forecast that PG&E has included in this proceeding should not be construed as DRA's acceptance of, or acquiescence with, those forecasts in this or any future test-year GRCs.

DRA has no objections to PG&E's MLP 2014 forecast for MWC BI (Maintain Buildings) and thus accepts the forecasted amount of $211,000, but DRA reduced PG&E's 2014 forecast for MWC JV (Maintain IT Apps and Infrastructure) to $194,000 from $1.11 million. Similarly, for MLP capital expenditure forecasts, DRA does not object to PG&E's requests for MWC 05 (Tools & Equipment), MWC 21 (Miscellaneous Capital), and MWC 22 (Maintain Buildings), but DRA reduced PG&E's forecast for MWC 2F (Build IT and Applications and Infrastructure) for both 2012 and 2014. PG&E's MWC 2F forecast for 2013 was $0.

The following discussion only addresses those MWC forecasts that DRA has objected to: (1) MWC JV (Maintain IT Apps and Infrastructure) and MWC 2F (Build IT Application and Infrastructure).

7.12.1.1 MWC JV (Maintain IT Applications and Infrastructure.)

PG&E's MWC JV seeks to implement two initiatives known as Materials Advanced Planning system and Transportation Management System (TMS). PG&E claims that its current material planning and forecasting system does not provide network inventory transparency that consistently maintains product availability in the right location for internal clients[1740]. "In addition, the current planning system's capability does not align with the sporadic demand patterns intrinsic to a gas and electric utility's maintenance and construction LOB."[1741] Therefore, PG&E seeks to replace its current inventory planning system with the Materials Advanced Planning and Scheduling System.

PG&E claims that within two years of implementation, this system would enable it to offset PG&E's inventory investment by up to $5 million and reduce capital equipment investment by up to $3 million (relative to work/demand levels). After reviewing PG&E's

[1740] Ex. 30 (PG&E-7), p. 4-21.

[1741] Id., pp. 4-21 to 4-22.

workpapers and application as well prior rate case information on this system, DRA's report recommended as follows:

> DRA recommends that the Materials Advanced Planning and Scheduling not be funded by ratepayers as the funds were requested in the 2011 rate case and implementation was deferred due to functional dependencies on other supply chain SAP enhancements.[1742] As such, PG&E already received the funds and ratepayers should not have to fund this project twice. Further, ratepayers should be receiving the benefit in cost savings already.[1743]

If in fact the Materials Advanced Planning and Scheduling system had the potential to provide such benefits as PG&E claims, with two years of the first date it is rolled out. It would indeed seem like a project PG&E would have requested and done a long time ago. It turned out that PG&E has in fact requested funds for this initiative as recently as its last rate case but failed to use those funds for the purpose requested. Therefore, the Commission should not authorize another set of funds for the same system.

DRA does not oppose PG&E's forecast for TMS. However, DRA adjusted the forecast cost to 86 percent of PG&E's forecast.

> As discussed more fully later in this report, DRA reviewed PG&E's IT Concept Estimating Tool forecasts from the 2011 GRC with recorded data and determined that actual results have been 86% of forecast based on the use of that tool. As such, DRA makes a similar adjustment to the Transportation Management System project forecast for 2014.[1744]

TMS forecasted costs are for the purchase and implementation of a SAP that is compatible with TMS's current manual processes. PG&E has already implemented a SAF-EWM system in 2011 that would integrate with other existing applications the Company already has to provide advanced strategic and tactical planning, route optimization and other benefits, once an SAP system compatible with TMS's current manual process is implemented.[1745]

[1742] Ex. 30, PG&E-7, p. 4-24 and PG&E Data Response to DRA data Request 252 Q01: "Yes, PG&E's 2011 forecast revenue requirement did include funding for the advanced planning and scheduling system because PG&E planned to implement the project during the 2011 GRC period."

[1743] Ex. 86 (DRA-18), p. 27.

[1744] Id.

[1745] Ex. 30 (PG&E-7), p. 4-25.

7.12.2 Capital Expenditures

In Transportation, MWC 2F is the corresponding capital expenditure for the same project that MWC JV was in the expense forecast. Therefore, any adjustments to MWC JV must be reflected in MWC 2F and vice versa.

> The 2014 and 2015 capital forecast of $4.3 million and $2.1 million under MWC 2F are to implement the Materials Advanced Planning and Scheduling system and the Transportation Management System initiatives.[1746]
>
> As discussed above in the MWC JV, DRA recommends that ratepayers not fund the Materials Advanced Planning and Scheduling system as PG&E had requested funding for this project in the 2011 GRC.
>
> DRA does not oppose the proposed Transportation Management System initiative, but does make an adjustment to 86% of PG&E's forecasted cost. The 86% adjustment reflects PG&E's actual results of other IT projects that PG&E had forecasted using the same IT concept estimate tool from the 2011 GRC.[1747]

7.13 Supply Chain – Sourcing Operations

Procurement of materials necessary for PG&E to serve its customers is the responsibility of Supply Chain –Sourcing Operations. In 2011, PG&E procured $4.4 billion in such goods and services, of which 77 percent was for procurement of services and 23 percent for materials purchases[1748]. The materials purchased included distribution equipment such as transformers, pipe, cable, fabricated and structural steel, software and equipment, chemicals, lubricants and other oil products, construction equipment (both purchases and rentals), vehicles and automotive parts, etc.

7.13.1 Expense

The MWCs in Sourcing are: MWC JL (Procure Materials and Services) and MWC JV (Maintain IT Applications and Infrastructure.)

[1746] Id., p. 4-21.

[1747] Ex. 86 (DRA-18), pp. 29 – 30.

[1748] Id., p. 5-1.

PG&E forecasts that Sourcing expense needs will increase by $6.4 million in 2014 over 2011 expenditures for a total forecast of $13.1 million.

7.13.1.1 MWC JL – Procure Materials and Services

PG&E's forecast for MWC JL in 2014 is $9.7 million. PG&E used 2011 as the base year for this forecast and escalated labor and non-labor costs based on PG&E's own escalation guidelines. The average cost per employee was determined from historical labor and related costs and used to adjust for additional headcount costs.

DRA used a five-year (2008 – 2012) average of recorded costs, escalated to 2014 dollars, to determine the appropriate forecast for MWC JL 2014 forecast and recommends that the Commission approve $7.3 million for test year 2014. DRA maintains that "a five-year average is the appropriate method as the recorded amounts in the table above lack a clear pattern and the year-to-year variance is low, with movement in both directions."[1749]

7.13.1.2 MWC JV – Maintain IT Applications and Infrastructure

PG&E seeks to implement the following three IT initiatives in this test year 2014 GRC: 1) Supplier Relationship Management Technology/Functional Upgrade; (2) Supplier Performance Management; (3) Integrate supply Chain with Energy Content Management.

According to PG&E, Supply Chain Sourcing "utilizes SRM software as the primary purchasing system to process purchase order workflow from requisition to integration into PG&E SAP financial system"[1750]. PG&E wants to upgrade the SRM system to Version 7.03 at a cost of about $17.8 million, of which $2.7 million is forecasted for 2015. The 2014 forecast expense for the SRM upgrade is $2.5 million. PG&E claims that upgrading SRM to Version 7.02 is critical to the productivity of the various lines of business and their compliance with their various obligations.

DRA does not oppose PG&E's efforts to upgrade SRM to Version 7.02, but recommends that the Commission normalize the expense over three years and that the forecast amount be reduced to 86 percent of the forecast to reflect the actual result of 2011 GRC projects that relied on PG&E's Concept Estimating Tool for IT. This recommendation is also consistent with all of

[1749] Ex. 86 (DRA-18), p. 32.

[1750] Ex. 30 (PG&E), p. 5-23.

DRA's recommendation for all Shared Services and IT projects that relied on the Concept Estimating Tool in this GRC.

DRA objects to the second IT initiative, Supplier Performance Management Technology, that PG&E proposes for the Supply Chain Sourcing. PG&E forecast $0.5 million to implement the Supplier Performance Management Technology. According to PG&E:

> This program includes formalized meetings between suppliers and PG&E executives multiple times a year to review the suppliers performance. The primary goals of the program are to enhance the relationship with key suppliers that provide critical goods and services and identify opportunities for continuous improvement. A standardized supplier scorecard is used to measure supplier performance and hold suppliers accountable. Sourcing's stated goal is for these suppliers to achieve a 90 or better score out of a potential 100 points. If they do not score well enough, they know that PG&E may need to switch to alternative sources of supply. Suppliers are scored on areas that impact cost, public an employee safety, operations and quality, customer satisfaction, supplier diversity, and sustainability.[1751]

This description of a formalized Supplier Performance Management program seems very much like PG&E's employee doing the work they are paid salaries to do under the guise of a program for which PG&E can then seek special funding in this rate cycle. PG&E claims that the current score-carding process is Microsoft Excel-based and requires extensive manual effort by Sourcing employees and creates delays. "The new system would not only have links and interfaces to data sources to pull information without intervention, but there would be a supplier front-end as well where approximately 100 suppliers can input information."[1752]

PG&E testimony never actually names the application that would replace the excel spreadsheet method that it has used to date, or explain how it would completely eliminate the requirement to manually input the data in a manner unlike the excel spreadsheet.

Similarly, PG&E's third IT initiative for Supply Chain Sourcing would integrate Supply Chain Sourcing with Enterprise Content Management by digitizing physical documents and migrating the existing content to the Company's Enterprise Content Management platform at a forecast cost of $0.3 million for 2014.

[1751] Ex. 30, p. 5-27.

[1752] Id., p. 5-28.

DRA recommends that the Commission reject the second and third IT initiatives proposed by PG&E to formalize meetings with suppliers and digitize physical documents. Given all the areas in this GRC that PG&E has requested digitizing physical documents as part of the migration to its new ECM platform, ratepayers are probably already duplicating funding for this process in this and earlier GRCs.

7.13.2 Capital Expenditures

PG&E's forecast for Supply Chain Sourcing Capital funding for IT initiatives is $10 million for 2014 and $4.8 million for 2015. Of these amounts, the Supplier Relationship Management 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 Enterprise Content Management, which PG&E forecast for 2014 at $1.6 million and $0.7 million in 2015.

PG&E does not forecast capital funding for implementing the Supplier Performance Management Technology program, which again reflects the fact that it primarily consists of PG&E's employees doing they work they were retained to do.

Consistent with DRA's recommendations under MWC JV in the preceding discussion, DRA recommends that the Commission approve the capital funding for the Supplier Management Technical/Functional Technology upgrade program, but reduce the authorized funding to 86 percent of the forecast to reflect actual results of such implementation in the 2011 GRC. This would reduce PG&E's forecast of $10 million to $7.3 million in 2014. DRA does not make any recommendations for the 2015 forecast as it is outside the current rate cycle, but DRA decision not to address the 2015 forecast at this time should not be viewed as an acceptance of that forecast or acquiescence with it[1753].

DRA recommends that the Commission deny approval of PG&E's forecast capital funding to integrate Supply Chain with Enterprise Content Management.

[1753] Ex. 86 (DRA-18), p. 34.

7.14 Real Estate

Shared Services and IT Real Estate consists of costs associated with managing PG&E's common utility plant buildings and yards, which include but are not limited to office buildings, service centers, shops, warehouses, construction and equipment yards, vehicle maintenance garages, customer service offices, Contact centers, data centers, and meetings and training facilities[1754].

PG&E's 2014 expense forecast for Corporate Real Estate is $32.6 million. PG&E acknowledges that recorded adjusted expense for 2011 was $12 million. Thus, the 2014 forecast is 172 percent more than 2011 recorded adjusted expense. PG&E claims that the primary reasons for this escalation are:

- Additional costs to maintain the Company's aging buildings and yards.
- Increased costs to complete building seismic safety upgrades.
- Additional costs to ensure compliance with the requirements of the ADA and Title 24 of the California Code and Regulations regarding accessibility at other Company buildings in addition to customer service offices.
- Expenditures to improve and provide additional offices space, rebuild outdated and inefficient service centers, and provide new buildings and yards to support PG&E's business needs.[1755]

None of the activities that PG&E now claims form the basis of the 172 percent escalation in costs from 2011 to 2014 are of recent origin. In fact, PG&E has been or should have been at work on all these activities for more than a decade.

Capital funding forecast for Corporate Real Estate in this rate cycles are: (1) $48.976 million for 2012, (2) $40.448 million for 2013 and $81.602 million for 2014. PG&E also forecast capital funding costs for 2015 and 2016, but DRA has not responded to forecasts that are outside this rate cycle.

7.14.1 Expense

Both the expense forecast and the capital forecasts are grouped into MWCs. The expense forecast MWCs for Real Estate are as follows:

[1754] Ex. 86 (DRA-18), p. 34; Ex. 30 (PG&E-7), p. 6-1.

[1755] Ex. 30 (PG&E-7), p. 6-2.

(1) MWC BI (Maintain Building) - $24.903 million;

(2) MWC JH (Implement Real Estate Strategy) - $6.837 million; and

(3) MWC JV (Maintain IT Applications and Infrastructure) - $850,000.

7.14.1.1 MWC BI – Maintain Buildings

MWC BI comprises of the following programs: a) Base Building Program; b) Building Seismic Safety Program and c) ADA Compliance Program. PG&E's test year 2014 forecasts for Base Building Program is $14.803 million, $4.191 million for Building Seismic Safety Program and $5.909 million for ADA Compliance Program[1756]. In 2011, the recorded adjusted costs for these same programs were $3.376 million, $2.714 million and $2.823 million, respectively[1757].

As previously noted none of these programs are new and PG&E would have been working on these programs for at least a decade. Further, there is no particular change in circumstances that suggests that Corporate Real Estate is facing challenges that are far more than it faced in 2011. Therefore, DRA uses a five-year average of recoded data from 2007 to 2012, escalated to 2014, to forecast PG&E's 2014 MWC BI funding.

Further, PG&E has made these exaggerated claims in the past. In the 2011 GRC, the Commission authorized $26.5 million for Corporate Real Estate MWC BI "but [PG&E] reduced its budget for MWC BI by $18.2 million to $8.3 million" upon the grounds that it need to fund higher priority work in other parts of the Company[1758].

PG&E argues that DRA's recommendation failed to take into account its "127 pages of testimony and 964 pages of detailed workpapers to support its real estate forecasts". This argument is preposterous. DRA reviewed all of the evidence and found them unconvincing to support a cost escalation that is 172 percent above what PG&E requested and was approved for just two years previously. Much of the 127 pages of testimony that PG&E claims supports its real estate forecasts consist of descriptions of PG&E's facilities[1759] and a general statement that seismic project would make structural upgrades to the facility[1760].

[1756] Eh. 30 (PG&E-7), p. 6-105.

[1757] Id,

[1758] Ex. 86 (PG&E-7), p. 38.

[1759] Ex. 30 (PG&E-7), pp. 6-44 to 6-50; 6-66 to 6-95.

[1760] Id., p. 6-47.

e) Stockton Gas Plant

This project will make structural upgrades to the Stockton Gas Plant building to meet the minimum PG&E design performance level of "Life Safety." The project will mitigate the seismic vulnerabilities of the building and also includes ADA improvements required by the local building department as part of the seismic upgrade permit. The forecast cost of the seismic upgrade at the Stockton Gas Plant is $1.2 million expense in 2012.

f) Livermore Office

This project will make structural upgrades to the Livermore Office building to meet the minimum PG&E design performance level of "Life Safety." The Livermore Office also houses PG&E's Livermore customer service office (CSO). The project will mitigate the seismic vulnerabilities of the building and also includes ADA improvements required by the local building department as part of the seismic upgrade permit. The forecast cost of the seismic upgrade at the Stockton Gas Plant is $1.0 million expense in 2012.

…

h) Santa Maria Service Center

This project will make structural upgrades to the Garage and Office/Warehouse buildings at the Santa Maria Service Center to meet the minimum PG&E design performance level of "Life Safety." The project will mitigate the seismic vulnerabilities of the building and also includes ADA improvements required by the local building department as part of the seismic upgrade permit. The forecast cost of the seismic upgrade at the Santa Maria Service Center is $1.2 million expense in 2012.[1761]

Except for the names of the facilities and in the case of Livermore the acknowledgement that the building also houses a CSO, all the descriptions are identical. It is unreasonable for PG&E' to argue that unless DRA has addressed each of these generalizations, DRA has not reviewed them or considered them in its analysis. DRA did not discuss these explanations separately and individually because they are simply not unconvincing and provide no evidence that deserves a response.

[1761] Ex 30 (PG&E-7), pp. 6-47 to 6-48.

The main drivers for Corporate Real Estate activities are all events that increase gradually from year to year, and the Commission has recognized that it is appropriate to use recorded costs to estimate the test year forecast for such activities or events.

Notwithstanding this fact PG&E argues:

> Using recorded expenditures as the primary tool to forecast future real estate costs is inappropriate because the Company's real estate forecasts are bottom-up forecasts that identify the specific projects needed to maintain and improve the Company's aging buildings and yards, achieve building seismic safety, comply with ADA and other regulations, increase the operating reliability of buildings that support critical business functions, and implement real estate solutions required to meet changing business needs.[1762]

The telling sentence in the foregoing argument is that "the Company's real estate costs forecasts are bottom-up forecasts", this means that the Company's real estate forecasts in the five years that DRA used for its average estimate were derived with the same bottom-up method that PG&E used in this 2014 rate case. Therefore, unless PG&E is claiming that the specific projects it needs to maintain and improve the Company's aging buildings and yards or comply with ADA and other regulations changes from year to year, the prior years recorded history forms the best basis for forecasting PG&E's future needs. As DRA noted, "maintenance should be a regular recurring event that can be planned and managed"[1763]. The delta between the recorded adjusted costs for MWC BI from year to year bears witness to this DRA testimony.

PG&E's protest of DRA's estimate for its Corporate Real Estate expense forecast continues:

> Q. 18 What will be the consequence of using recorded expenditures to forecast future real estate expenditures?
>
> A. 18 If the Commission were to accept DRA's position, it would be agreeing to a "self-fulfilling" premise that would never allow PG&E's real estate program expenditures to increase significantly above recorded expenditures. DRA's position that the Commission should not approve forecasts that are higher than the average of the Company's last five years of recorded expenditures

[1762] Ex. 30 (PG&E-7), p. 6-7.

[1763] Ex. 86, p. 38.

> is unreasonable for three reasons: (i) First, it ignores current and future conditions that differ from past conditions; (ii) Second, it does not consider the appropriateness of the specific activities and projects comprising each of PG&E's real estate program forecast; and (iii) Third, it requires PG&E to spend more than authorized in order to show the higher level of recorded expenditures necessary to gain DRA's support for future (General Rate Case) GRC forecasts.[1764]

The foregoing discussion of the consequences of using recorded expenditures to forecast future real estate expenditures is a good example of why DRA should not be expected to address every single narrative pretext in PG&E's testimony before making a forecast recommendation for PG&E's Corporate Real Estate. The discussion deliberately ignores the facts, which DRA addressed in its testimony. Consider for instance the argument that using recorded expenditures "requires PG&E to spend more than authorized in order to show the higher level of recorded expenditures necessary to gain DRA's support for future."[1765] DRA noted that in 2011 PG&E was authorized $27.5 million … but reduced its budget for MWC BI by $18.2 million to $8.3 million." DRA explained PG&E's rationale for the reduction as follows:

> PG&E says the "[d]ecrease reflects the decision not to pursue in 2011 the following projects in order to fund higher priority work in other parts of the Company: (i) 77 Beale St./One Market Plaza project; (ii) Customer Office Refurbishment Project; (iii) certain non-mandatory ADA surveys; and (iv) certain Base Building maintenance projects (e.g., roofing repairs, HVAC repairs, carpet replacement, interior painting)."[1766]

These facts reflect that the rationale which supports using recorded cost averaging is that which requires PG&E to spend what it was authorized rather than more than it was authorized in order to show a higher level of recorded expenditure. The audacity with which PG&E makes this claim despite evidence to the contrary reflects the PG&E's attitude towards much of its recommendations for Shared Services and IT.

PG&E also argues that using recorded cost averaging "does not consider the appropriateness of the specific activities and projects comprising each of PG&E's real estate

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[1764] Ex. 60 (PG&E-22), p. 6-9.

[1765] Id.

[1766] Ex. 86 (DRA-18), p. 38, citing *Pacific Gas and Electric Company's August 3, 2011 Budget Report in Compliance with California Public Utilities Commission Decision 11-05-018, p.8.6.*

program forecasts."[1767] Consider PG&E's rationale for transferring funds from MWC BI to other projects outside in 2011. Among the projects deferred were 77 Beale Street/One Market Plaza project and certain non-mandatory ADA surveys. These same projects occupy more than 10 pages of discussions in this GRC[1768]. Here again the specific activities and projects comprising the real estate program forecasts, show that they do not support the 172 percent escalation of costs, when only two years ago they were considered lower priority work.

When one reviews each of the programs separately, PG&E's cases looks even worse. Discussing the ADA initiative for instance, PG&E stated:

> 1) Initiative to Enhance ADA Compliance at Company Buildings
>
> CRE Enhanced ADA Compliance Program will assure ADA Title 1 (employee accessibility) and Title 3 (public accessibility) to all CRE-managed buildings. When used in this chapter, "ADA compliance" is intended to include Title 24 compliance where appropriate.
>
> This initiative includes the cost of performing detailed ADA accessibility assessments at approximately 190 CRE-managed buildings. These surveys will establish updated accessibility condition information for each building, identify recommended accessibility improvements with the assistance of external ADA experts, and implement these recommendations.
>
> Following enactment of the ADA in 1992, CRE completed "readily achievable barrier removal" projects for ADA Title 1 and Title 3 compliance in its buildings. However, as noted above, those original efforts may be outdated and may no longer meet current ADA requirements.[1769]

First note that CRE completed ADA compliance on all its buildings following enactment in 1992, and now only wants to review its compliance status because "those original efforts may be outdated and may no longer meet current ADA requirements", to which one might well say: "On the other hand, they may still be in compliance." The point is that without knowing whether it is actually out of compliance, PG&E escalated its ADA forecast by more than one hundred

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[1767] Ex. 30 (PG&E-7), p. 6-9.

[1768] Id., 77 Beale St./ One Market Plaza: Page 6-95 to 6-100, p.6-25; ADA Compliance: Page 6-55 to 6-63, 6:25.

[1769] Ex. 30 (PG&E-7), pp. 6-56 to 6-57.

percent on pure speculation. The CPUC has had the same handicap ramp up the front of the building, the same size rest rooms, the same sitting spaces and other elements that usually comprise ADA compliance requirements for more than 10 years. Assuming they were in compliance at the time they were built and have not fallen out of compliance, how much should the CPUC spend in reviewing the likelihood that the facilities are not in compliance. It is important to note that PG&E seeks to conduct these surveys for all of its CRE managed buildings. It is unnecessary make work that would again result in funds being transferred to other areas that the Company identifies as higher-priority work.

7.14.1.2 MWC JH – Implement Real Estate Strategy

PG&E's Real Estate Strategy consists of the Real Estate Planning and Transaction program and the Real Estate Solutions program expensed in MWC JH. PG&E maintains that its Real Estate Planning and Transactions program will improve the management of vacant properties and reduce future costs of underutilized and surplus real estate[1770]. Real Estate Solutions program will form the basis for CRE to refurbish, relocate, replace and close offices and service centers to correct condition deficiencies, improve functionality, implement workplace improvement and meet business needs[1771].

PG&E's 2014 expense forecast for Real Estate Planning and Transactions program is $5 million dollars and for Real Estate Solutions is $2 million. In 2011, the recorded expense cost for Real Estate Planning and Transactions was $3.1 million and for Real Estate Solutions was $0[1772]. The total forecast funding for MWC JH for 2014 is $6.8 million to be exact and 76 percent higher than the 2012 actual recorded expense[1773]. In fact, PG&E's 2014 recorded expense forecast for MWC JH is higher than it has ever been in the last five years during which time it only exceeded $4 million once[1774].

[1770] Id.. p. 6-25.

[1771] Id.

[1772] Id., p.6-102; Ex. 86 (DRA-7), pp. 39 – 40.

[1773] Ex. 86 (DRA-7), p. 40.

[1774] Id., See Table 18-35 showing recorded expense for MWC JH from 2007 to 2012 as $3.976 million, $4.586 million, $3.191 million, $3.250 million, $3.130 million, $3.887 million respectively.

DRA used a five year average of recorded expense, escalated to 2014, $4.04 million as the appropriate test year forecast for MWC JH[1775].

7.14.1.3 MWC JV – Maintain IT Applications and Infrastructure

MWC JV is the IT Applications and Infrastructure component of CRE's Base Building Program and the Real Estate Planning and Transaction Program. PG&E forecast $0.85 million for this program in test year 2014, with $0.65 million forecast for the Base Building Program and $0.2 million for the Real Estate Planning and Transactions program.

DRA opposes rate payer funding for MWC JV because PG&E was funded for a similar Real Estate Planning and Transactions program initiative in 2011 but PG&E did not implement the initiative. Regarding the Base Building Program initiative, DRA writes:

> While PG&E states that the total revenue requirement provided by the 2011 GRC decision was less than PG&E's 2011 GRC forecast and therefore insufficient to support all of the work forecast in PG&E's 2011 GRC testimony, PG&E's March 2012 Budget Report shows that PG&E had $608,000 left in its 2011 budget. … Ratepayers should not be required to pay twice.[1776]

7.14.1.4 MWC 22 (Maintain Building)

PG&E forecasts the capital cost for its Base Building Program and Building Seismic Safety Program in MWC 22. The Base Building Program capital costs consist of replacement costs that PG&E claims would "extend the life of building components, correct building component deficiencies, improve equipment-operating efficiencies, replace failed or functionally obsolete building components, and increase the operating reliability of PG&E's buildings and yards."[1777]

The Building Seismic Safety Program aims to improve the seismic performance of Company buildings located in areas predicted to experience a higher risk of strong seismic

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[1775] Id., p. 35.

[1776] Ex. 86 (DRA-7), p. 41.

[1777] Ex. 30 (PG&E-7), p. 6-26.

activity. PG&E has completed seismic safety work in 76 of its buildings and forecasts an additional 16 buildings to be completed in this rate cycle.[1778]

PG&E's 2014 capital expenditure forecast for its Base Building Program is $44.125 million and for its Building Seismic Safety Program is $1.549 million. In 2012 PG&E recorded costs for MWC 22 was $46.733 million.

DRA accepts PG&E's 2012 recorded costs for MWC 22 but recommends that the Commission use a five-year average forecasting methodology to set PG&E's test year 2014 costs.

The Commission should not rely solely on PG&E's forecast as the timing and scope of the projects included in its request are at the discretion of PG&E.

> PG&E's August 3, 2011 Budget Report Illustrates that the ratepayer funds provided in the 2011 GRC for MWC 22 (previously MWC 78 and MWC 88) have been used elsewhere. In that August 3, 2011 Budget Report, the MWC 22/23 (previously MWC 78) budget was decreased by $15.4 million from the GRC imputed amount of $65.4 million to $50 million. Also, MWC 22 (previously MWC 88) was decreased by $5.2 million from GRC imputed amount of $5.7 million to $0.5 million. …
>
> …DRA simply highlights the fact that … ratepayers should not pay based solely on what PG&E management wants, but rather based on what PG&E has delivered.[1779]

7.14.1.5 MWC 23 (Implement Real Estate Strategy)

MWC 23 represents capital cost for the Real Estate Strategy Solutions Program. PG&E's 2014 capital forecast for MWC 23 is $35.4 million. This 2014 forecast amount exceeds anything that has been recorded MWC 23 or its predecessor accounts in the past six years. "In fact, PG&E's 2014 request for MWC 23 exceeds what PG&E has spent in this MWC for the past six years combined."[1780] Recorded cost for Real Estate Solution Capital in 2011 was $6.4 million.

[1778] Id., p.6-41 to 6-42.

[1779] Ex. 86 (DRA-7), p. 43.

[1780] Id., p. 45.

DRA recommends that the Commission authorize $10 million for MWC 23 test year 2014 expenditure. "DRA's forecast is based on its recommendation that one project [in the Program] be rejected and that the remaining balance be normalized over three years."[1781]

One remarkable aspect of PG&E's escalation of its forecast for MWC 23 is the degree to which the work is both discretionary and cosmetic. Describing what it saw as the future state of Real Estate Solutions Program, PG&E stated:

> CRE forecast for the Real Estate Solutions Program includes expenditures to refurbish or replace office and service center buildings to correct condition deficiencies, improve functionality, implement workplace improvements, and meet current business needs. CRE's forecast for this program also includes expenditures to provide additional office space where needed, refurbish floors at 77 Beale Street and improve the operating reliability of the Fairfield data center.[1782]

DRA fails to understand why PG&E would oppose normalizing the cost of refurbishing floors and creating additional office space rather than creating a rate shock in a GRC that PG&E is planning the most ambitious optimization and improvement of every single asset it owns regardless of the need or benefit of doing so in one rate cycle.

The one project that DRA is opposed to including in MWC 23 is the plan to provide a dedicated 12kV power feed from the Cordelia Substation, located approximately six miles away, to the Fairfield Data Center. The project is essentially more of a question of convenience rather than need. The Fairfield Data Center has been superseded by PG&E's new Sacramento Data Center, which 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. In addition, CAISO maintains visibility with the same resources that the Data Centers are monitoring, and 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.

> Several utility power disruptions to the Fairfield Data Center have occurred since December 2011. While most disruptions were momentary, one outage was over 22 minutes in duration. Secondary systems such as

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[1781] Id., p.45 illustrating the removal of the program and normalization of the remaining costs as follows: ($35.378 - $5,233)/3 + 10.048.

[1782] Ex. 86 (DRA-18), p. 6-66.

> uninterruptible power systems, batteries and standby generators are in place to support critical operations when utility power disruptions occur. However, any utility power disruption carries the potential of catastrophic data center failure if any of the secondary systems or system components fails.[1783]

In addition to the fact that there are cheaper alternatives to incurring this $5 million for a 12kV already available to the data center, PG&E upgraded the Fairfield Data Center in the period leading up to the 2011 rate cycle and did not see the need or urgency to add the dedicated 12kV line. Therefore, as the "Fairfield Data Center … already has secondary systems, DRA recommends not funding a dedicated power feed" to the Center[1784].

7.14.2 Capital Expenditures

Capital costs under MWC 2F are for Base Building Program and the Real Estate Planning and Transaction Program.

7.14.2.1 MWC 2F – Build IT Applications and Infrastructure

PG&E's 2014 forecast for MWC 2F is $0.350 million under the Base Building Program and $0.2 million for Real Estate Planning and Transmission program. The capital expenditure under the Real Estate Planning and Transmission Program is primarily to integrate CRE's stand-alone occupancy planning database with PG&E's information management systems.

PG&E identified both the Base Building Program and the Real Estate Planning and transaction Program in its 2011 GRC but claimed that total revenue requirement the Commission authorized for the 2011 GRC was insufficient to support all of the work forecast in PG&E's 2011 GRC testimony. By this rationale, unless the Commission approves the exact amount that PG&E requested in its GRC applications, PG&E has the discretion to refrain from implementing programs sought in that GRC and request the same programs again in subsequent GRCs ad infinitum.

DRA opposes ratepayer funding for Base Building Program and the Real Estate Planning and Transaction Program. PG&E has not spent its 2011 budgeted expense amounts for IT and

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[1783] Ex. 30 (PG&E-7), p. 6-102.

[1784] Id., p. 45.

should not be approved for more ratepayer funds for programs it has already presented to the Commission and received authorized funding in prior rate cases.

Environmental Program consists of the forecasts for Administrative and General (A&G) expenses, Operations and Maintenance expenses and Capital expenditures necessary to manage PG&E's Environmental Organization and implements its programs and policy. These expenditures include the costs for complying with environmental laws and regulations, managing PG&E's expansive land resources, protecting sensitive species and natural resources and remediating environmental contamination from historic operations, among others[1785]. PG&E claims that the workload for its environmental organization increase as its investment in infrastructure upgrades increase.

There are three categories of Environmental costs[1786]:

(1) A&G expenses for the organizations that charge to A&G;

(2) O&M expenses and capital expenditures within the Environmental Major Work Categories (MWC), and

(3) Costs embedded in capital and expense projects, activities, and programs managed by other departments.

Only the Categories for A&G expenses and O&M and capital expenditures are forecast under this section on Environmental Program. Costs embedded in projects and programs managed by other departments are not part of Shared Services and IT and are discussed in under other lines of business.

7.14.3 Expense

The major work categories for expenses under the Environmental Program are:

(1) MWC AK – Manage Environmental Operations;

(2) MWC AY – Habitat and Species Protection;

(3) MWC CR – Manage Waste Disposal and Transportation;

(4) MWC ES – Environmental Projects and Initiatives;

(5) MWC FA – Special A&G/Other Costs;

[1785] Id., p. 7-1.

[1786] Id., p. 7-3.

(6) MWC JE – Manage Land Services,

(7) MWC JK – Manage Environmental Remediation;

(8) MWC JV – Maintain IT Applications and Infrastructure;

DRA does not oppose PG&E's forecast of expenses for MWC AY, MWC CR, MWC FA, and MWC JK, therefore will not be discussing them in this opening brief.

The major work categories for capital under the Environmental Program Section are:

(1) MWC 5 – Land and Environmental Management Tools and Equipment

(2) MWC 12 – Environmental Operations

(3) MWC 2F – Build IT Applications and Infrastructure.

DRA does not oppose PG&E's capital forecast for MWC 5, and therefore will not discuss it in this opening brief.

7.14.3.1 Operations and Maintenance Expense

MWC AK – Environmental Operations:

Environmental Operations are costs for routine environmental work by PG&E, including day-to-day work costs that are part of each facilities normal operation, such as labor costs of environmental professionals and facility personnel who perform environmental compliance tasks, as well as materials, contracts and fees[1787].

PG&E forecast $16.1 million for test year 2014 MWC AK expenses. The recorded costs for 2011 was $9.7 million. DRA recommends $11.1 million for MWC AK based on a five year average of recorded costs escalated to 2014 dollars. DRA reasoned that because the main driver for the cost escalation from 2011 to 2014 is $5.3 million Air Resources Board (ARB) annual Cost of Implementation Fee, which is recoverable from end-use gas transportation and bundled electric generation customers, ratepayer should not be burdened with that cost.

> PG&E states that the main driver in the 2014 increase is $5.3 million in MWC AK for the Air Resources Board (ARB) annual Cost of Implementation Fee legally mandated by Assembly Bill (AB) 32 which is recoverable from end-use gas transportation and bundled electric generation customers. PG&E states that the remaining increase is necessary to pay increasing permit fees to regulatory agencies and for increases in labor and contract costs.

[1787] Id., p. 7-21.

…

> Subsumed in that [DRA] forecast is DRA's recommendation that the $5.3 million in the ARB annual Cost of Implementation Fee should not be included in PG&E's revenue requirement since this is recoverable from end-use gas transportation and bundled electric generation customers.[1788]

In its rebuttal to DRA's testimony, PG&E "…accepts the forecast in this case [exclusion of $5.3 million in ARB fees] because the Commission has ruled that the ARB implementation costs are recoverable in other proceedings."[1789]

MWC ES – Environmental Projects and Initiatives:

Environmental Project and Initiatives includes costs associated with repairing, replacing and upgrading equipment to comply with environmental regulations. Relevant projects include retrofits and repairs of various hazardous waste storage tanks, facilities, and storm water collection systems at facilities, repairs to vehicles washing systems at facilities, and miscellaneous compliance-driven expense projects[1790].

PG&E's 2014 expense forecasts for MWC ES for test year 2014 is $0.9 million. The recorded cost for 2011 was $0.5. However, PG&E claims that it "anticipates" an "increase in retrofits and repairs of fuel and hazardous waste storage tanks required by regulation and for SPCC Plan modifications at distribution substations.[1791]" PG&E does not explain why it "anticipates" this increase in retrofits and specifically "at distribution substations", which give it a touch of the mystical. However, the proof necessary to support a rate increase should be more than a utility's claim of "anticipation". As the record in this GRC clearly shows PG&E appears to "anticipate" an increase in everything that would increase its forecasted expense and capital costs, including MWC ES.

DRA recommends a forecast of $0.882 million.

> DRA believes its forecast of $0.882 million is sufficient to fund these projects and initiatives, and notes that in its testimony, PG&E forecasted

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[1788] Ex. 86 (DRA-18), p. 49.

[1789] PG&E rebuttal accepts this. PG&E-22, page 7-11, line 30 continuing to page 7-12, line 2.

[1790] Ex. 30 (PG&E-7), p. 7-26.

[1791] Id.

> most of the increase in 2012, yet the actual recorded 2012 expense was $177,000 less than PG&E had forecasted for that year.[1792]

MWC JE – Manage Land Services:

PG&E manages a variety of land rights support activities under MWC JE, including maintenance of the Land Rights Library, coordination with state Board of Equalization, staff training and maintenance of guidance documents and management of properties leased or licensed by others. The land management activities in this category include sustainable forest management and fuel (i.e., timber) reduction projects, annual timber inventory, seed storage and conifer seed growing.

PG&E also seeks to include funding for $1.1 million initiative to develop a land stewardship management program under MWC JE and $0.2 million to support other land management activities and labor escalation. PG&E's total expense forecast for MWC JE is $3.3 million compared with $2 million recorded cost in 2011.

PG&E's bankruptcy in 2003 required PG&E to establish a Land Stewardship Council where PG&E's shareholders would sponsor $10 million dollars by giving $1 million annually for the stewardship management program much like PG&E has described in MWC JE.

> Q. What's the role of the stewardship council, then? I'm trying to understand after -- well, let me put it this way simply: Can you tell me what the role of the stewardship council is with respect to these parcels of land?
>
> A. Yeah. This stewardship council was created as a result of a bankruptcy proceeding. And I think generally the best way to describe what their responsibility is governance over the overseeing of the development of these land conservation plans. They are an independent nonprofit organization, and they act as an advisory body to provide guidance and governance over what to do with the disposition of these lands.[1793]

When asked the difference between the land conservation council activities that was established in PG&E's bankruptcy and the stewardship activities that PG&E is proposing under MWC JE, PG&E's witness could not articulate any difference.

[1792] Ex. 86 (DRA-18), p. 51.

[1793] Tr. Vol. 20, p.2277.

Q. Are you familiar with the Land Conservation Council Program that PG&E set up at the time of its bankruptcy?

A. The Land Conservation Commitment, yes, I am.

Q. Is this the same type of stewardship program you're talking about here?

A. It's part of it in that as part of the Land Conservation Commitment, there will be conservation easements placed on many of PG&E's 140,000 acres of watershed lands. And so part of what's embedded in the 1.1 million is funding to manage those lands consistent with the new conservation easements. But, as the response in Answer 11 lays out, there are other activities that are not necessarily directly related to the Land Conservation Commitment. It's [sic] activities that we do now, but we want to do more proactively across particularly the non-watershed lands.[1794]

It is a disturbing coincidence that PG&E $1.1 million forecast for this stewardship council is exactly the same amount that PG&E's shareholders were required to pay under the 2003 bankruptcy plus what would amount to a 10 percent interest for payments of $10 million dollars made over ten years.

DRA recommends $2.1 million forecast for MWC JE. DRA's forecast was derived from a five-year average of recorded costs escalated to 2014 dollars. DRA does not support ratepayer funding for PG&E's Land Stewardship Program. Even if PG&E could articulate the difference between its Land Stewardship Program and the Land Conservation Program that its shareholders were supposed to be responsible for, "PG&E must already inspect and manage its properties. And while PG&E states that "active management cost less by reducing illegal dumping, trespass, encroachments, or other illegal third party activities on company lands"[1795] PG&E's proposal does not reflect these savings. DRA does not see sufficient benefit for spending $1.1 million on this program."[1796]

MWC JV – Maintain IT Application and Infrastructure:

[1794] Tr. Vol. 23, pp. 2896 – 2897.

[1795] Ex. 34 (PG&E- 7), p. WP 07-09, p. WP 7-46.

[1796] Ex. 86 (DRA-18), p. 54.

PG&E forecasts $4.4 million for MWC JV expense to support several initiatives that sound like they are only remotely connected to maintaining IT application and infrastructure. These initiatives include: "Enhancing PG&E's Environmental, Health, and Safety Management System, which include deploying mobile technologies; Improving environmental review and permitting of construction projects; Expanding programmatic and regional permits, Enhancing electronic document management; and Upgrading the Building and Land Management System."[1797] Of course, PG&E projects these activities to increase over 2011 costs.

The recorded adjusted cost for MWC JV in 2011 was $0.5 million[1798].

DRA recommends $1.1 million in 2014 expenses for MWC JV, based on the further recommendation that two projects proposed by PG&E under this MWC should be denied.

> DRA opposes ratepayer funding for two projects proposed by PG&E as there are minimal benefits to ratepayers. PG&E's proposal to spend $2.8 million in expense in 2014 (and $3.32 million in capital) for Enhancing PG&E's Environmental, Health, and Safety Management System seems excessive to achieve cost avoidance in data entry and reporting efficiencies, decreased costs of compliance, software purchases, licenses and hosting fees.[1799] In addition, PG&E is not able to quantify these supposed cost avoidances. Similarly, PG&E's proposal to spend $0.5 million in expense in 2014 (and $0.65 million in capital) for enhancing electronic document management also appears excessive to achieve non-cost benefits. PG&E did not include any cost benefits for this project.[1800]

7.14.3.2 Administrative and General (A&G) Expense

PG&E forecast A&G expenses for Shared Services IT under MWC FA and JK. DRA does not oppose PG&E's forecast of expenses for MWC AY, MWC CR, MWC FA, and MWC JK, therefore will not be discussing them in this opening brief.

[1797] Id., p. 55, Ex. 30 (PG&E-7), p. 7-26.

[1798] Id.

[1799] Ex. 34 (PG&E-7), p. WP 07-09, p. WP 7-51.

[1800] Ex. 86 (DRA-18), p. 56.

7.15 Information Technology Costs

Information Technology Costs are for services provided by PG&E's IT organizations under the following three portfolios of initiatives: (1) Baseline Operations Portfolio, (2) Technology Reliability Portfolio and (3) Business Technology Project Portfolio.

Baseline Operations are for ongoing maintenance and operations of PG&E's existing systems and infrastructure. PG&E maintains that Baseline Operations must remain dynamic and expand to support new functions in order to accommodate new projects that are being deployed by the Company.

Technology Reliability Portfolio "represents PG&E's physical asset replacement initiatives and break-replace services that are required to maintain the current operational and reliability targets for all computing and network systems."[1801] The Reliability Portfolio also encompasses enterprise-wide information technology projects, enabling critical cybersecurity functionality and internal IT projects targeted at improving services that IT provides to the Company[1802].

Business Technology Project Portfolio enable and support PG&E's lines of business in providing safe and reliable service to PG&E's customers and support the full range of PG&E's business processes.

PG&E forecasts the expense cost for these three portfolios in MWC JV – Maintain Applications and Infrastructure, and the capital cost in MWC 2F – Build Application and Infrastructure.

7.15.1 Expense

PG&E currently lists all IT expenses used by the IT Organization under MWC JV. These expenses include costs for all three portfolios covering ongoing maintenance, operations and repair for PG&E applications, systems and infrastructure.

7.15.1.1 MWC JV – Maintain Applications and Infrastructure

PG&E forecasts $261.603 million for MWC JV. The 2011 recorded cost was $216.959 million. PG&E claims that the key drivers for the increased cost in MWC JV are an increase in

[1801] Ex. 35 (PG&E-8), p. 8-2.

[1802] Id., p. 8-2 to 8-3.

contract costs of approximately $39.4 million, increased labor costs of approximately $2.6 million, and increased cost of approximately $5.7 million in 2014 for 42 additional employees."[1803]

DRA recommends $231.8 million for MWC JV. DRA derived its forecast by trending out PG&E's 2014 costs for its Baseline Portfolio from 2008 to 2012. Although DRA did not have the 2012 Baseline Portfolio recorded costs at the time DRA prepared its testimony, DRA "used PG&E's 2012 budgeted Baseline Portfolio to total MWC JV and applied that percentage (96%) to 2012 recorded MWC JV cost of $216 million"[1804]. This trending resulted in a $221 million forecast for the Baseline Portfolio. The remaining $11 million in DRA's forecast was derived "by using a five year average of PG&E's Lifecycle functional area, accepting PG&E's 2014 forecast for technology reliability project functional area, and rejecting PG&E's 2014 forecast for the continuous improvement functional area".

Regarding the functional areas and DRA's rejection of the continuous improvement functional area, DRA reasoned as follows:

> The three functional areas that make up the Technology Reliability Portfolio are: lifecycle activities; technology reliability projects; and, continuous improvement initiatives. Lifecycle activities are the replacement and upgrade of PG&E's billion dollar plus IT asset base. Technology reliability projects are large-scale information technology projects originating within the IT organization. Continuous improvement initiatives include costs for initiatives specifically designed to improve IT services and reduce costs for IT services.
>
> …
>
> DRA rejects PG&E's 2014 forecast for the continuous improvement functional areas as it includes two projects that DRA opposes. The two projects are Record Management Archival project to design and implement a records management system built around PG&E's Documentum tool, and Service Management project that PG&E states will reduce the frequency and duration of IT systems and application outages and provide IT better visibility into issues in its environment.

[1803] Id., p.62, citing Ex. 30, p. 8-35.

[1804] Ex. 86, p. 62.

> DRA opposes the Record Management Archival project as it places the cart before the horse. As PG&E provides in its testimony "PG&E is in the process of building the Documentum tool. When the work forecast in the 2011 GRC is complete, Documentum will provide some of the capabilities that PG&E needs for its Records Management Archival program. However, it is not robust enough to provide all of the required functionality so PG&E will need to add additional tools and capabilities forecast in this rate case."[1805] DRA opposes ratepayer funding until PG&E has demonstrated that the 2011 GRC funding it has received for the enterprise-wide data archival and records management program is operational.
>
> DRA is also opposed to ratepayer funding for PG&E's Service Management project as continual improvement should be implicit in PG&E management activities. Ratepayers should not have to fund specific projects to gain improvements.
>
> As discussed in Exhibit DRA-13 (Customer Care Costs), DRA rejects PG&E's forecasted Smart Meter Opt-Out Program costs. DRA removed $270 thousand in associated cost from MWC JV from this section. Taken together, DRA recommends $231.8 million in MWC JV for 2014.[1806]

7.15.2 Capital Expenditures

PG&E forecasts costs to design, develop and enhance applications, systems and infrastructure technology solutions under MWC 2F. In the past PG&E recorded these costs in eight separate major work categories of capital expenditure. PG&E's 2014 forecast for MWC 2F is $212.3 million, a 30 percent increase over actual 2012 recorded costs.

> PG&E forecasts capital expenditures of $105.7 million in 2014 for Lifecycle functional area, $83.3 million in 2014 in Technology Reliability functional area, and $23.4 million in 2014 for its Continuous Improvement functional area. In sum, PG&E is forecasting total capital expenditures in MWC 2F of $212.3 million in 2014. This is a 30% increase from PG&E's actual 2012 recorded capital cost.[1807]

DRA recommends $161.3 million for MWC 2F, by normalizing one project in the Technology Reliability functional area and adjusting the other project to 86 percent of the forecast.

[1805] Ex. 30 (PG&E-7), p. 8-58.

[1806] Ex. 86 (DRA-18), pp. 61 – 63.

[1807] Id., citing Ex. 30, PG&E-7, p.8-63, (212,321 – 163,444)/163,444 = 29.90%.

> DRA reduced PG&E's Identify and Access Management project to 86% of forecast, and normalized PG&E's Telecommunication Network Enhancement project. The adjustment is based on PG&E's actual to 2011 GRC forecast of IT projects that used the concept cost estimating tool. This is discussed further below. DRA normalized PG&E's Telecommunication Network Enhancement project as PG&E states that the core and edge telecommunication networks, as currently constructed, will meet the projected demand and capacity for the next three years. After adjusting for these two projects, DRA's recommendation for the Technology Reliability functional area is $55.6 million for 2014.[1808]

The resulting $55.6 million from DRA's adjustment to the Technology Reliability functional are added to PG&E's forecast of $105.7 million for Lifecycle forecast constitutes DRA's $171.3 million recommendation for MWC 2F.

Consistent with its recommendations throughout the review and analysis of Shared Services and IT functions, DRA rejected two projects in the Continuous Improvement functional area.

> In the Continuous Improvement functional area, DRA rejects both projects and recommends $0 dollars in 2014. The two projects in the Continuous Improvement functional area are Records Management Archival and Service Management projects. As discussed in the related expense section above, DRA objects to ratepayer funding until PG&E has demonstrated that the 2011 GRC funding it has received for the enterprise-wide data archival and records management program is operational. There is no ratepayer benefit to be gained from funding additional tools and capabilities if the enterprise-wide archival is not operational. Additionally, DRA questions why PG&E continued the 2011 GRC funded archival project knowing that it did not offer all the functionality that PG&E required.
>
> Also, DRA is opposed to ratepayer funding for PG&E's Service Management project as continual improvement should be implicit in all of PG&E's management activities. DRA is also opposed to PG&E's forecasted Smart Meter Opt-Out Program Cost as discussed in Exhibit DRA-13. In sum, DRA recommends $161.3 million for MWC 2F in 2014.[1809]

[1808] Ex. 86 (DRA-18), pp. 65 – 66.

[1809] Ex. 86 (DRA-18), p. 66.

7.16 **Information Technology Cybersecurity**

DRA does not oppose PG&E's proposed IT Cybersecurity program, but recommends that ratepayer funding be reduced to 86% of PG&E's forecast for the reasons discussed in section 7.18 below. [1810]

7.17 **Records Management**

Throughout DRA's review of Shared Services and IT capital forecasts, in every section where PG&E made a forecast using its "Concept Cost Estimating Tool", DRA recommended that the Commission adjust the PG&E's request to 86 percent of the forecast. DRA made these recommendations based on its review of PG&E's actual 2011 GRC forecast of IT projects that used the concept cost estimating tool.

In this section, we reproduce the reasoning from DRA's report that supports this cost estimating policy or methodology for PG&E's business technology IT forecasts:

> PG&E uses its "Concept Cost Estimating Tool" to forecast costs for proposed IT application development projects. According to PG&E, a more detailed cost estimate is prepared when the project requirements, strategy and technology solutions are more fully developed, just before the commencement of the project.[1811]
>
> PG&E states that the concept estimating tool applies standard industry practices for IT project estimating. PG&E has been using the concept estimating tool since 2008 as the basis for generating the initial cost estimate for application development projects. The cost forecast for the Business Technology IT projects presented by the LOBs in PG&E's 2014 GRC were developed using the IT concept cost estimating tool. In the 2011 GRC, PG&E introduced the concept estimating tool as part of its process to estimate the costs of line of business technology application development projects. Since that time, the tool has remained largely the same; however, some adjustments and refinements have been made to the tool to improve its accuracy.[1812]
>
> PG&E states that the concept cost estimating tool is a computer based tool built in Excel and takes the form of a workbook containing several tabs. The tool includes a series of checklists and templates that the user

[1810] Ex. 86 (DRA-18), p. 65.

[1811] Ex. 30 (PG&E-7), p. 8-66.

[1812] Ex. 30 (PG&E-7), p. 8-66.

completes to ensure all types of costs are included. The tool was developed by PG&E and is based on the standard industry approach for estimating IT application development costs early in the project lifecycle. To complete the checklist and generate the initial concept estimate, the IT project team works with the line of business to outline the business need for the IT project, understand the business requirements, outline the IT project benefits, and develop the timing for delivering the project. Using the information collected from the line of business, the IT project team completes the concept cost estimating checklist.[1813]

Built into the concept cost estimating tool are a series of assumptions that the model uses, along with the information the user inputs into the tool, to calculate the various costs that roll up to the initial project forecast. The assumptions include percentage splits between capital and expense amounts, allocations of time across the different project stages (i.e., project development, testing, training, etc.) and burden amounts. Percentage splits between capital and expense are based on advice from PG&E's Capital Accounting organization for application development projects. Time allocations among the project stages are based on industry benchmark analytics. Percentages for burdens are based on information provided to IT by PG&E's Finance organization. Standard cost information and assumptions built into the model, such as labor rates and burden rates, are regularly updated by the IT team responsible for the concept cost estimating tool. Updates and changes are tracked in the Usage and Version Control tab included with the model.[1814]

Using the concept estimating tool requires the user to answer questions, complete checklists and fill-in templates. The checklists and templates are designed to ensure that the IT project team and line of business sponsors have identified and considered all of the required project components such as security needs, infrastructure requirements, O&M costs, and staffing needs.[1815]

After completing the checklists and templates and generating a project forecast range, the IT project team evaluates the different program elements and determines the project cost forecast within the forecast range generated by the model. The IT team relies on its professional judgment and experience with application development projects in this evaluation, taking into consideration several key elements such as: PG&E's confidence level relative to undertaking the IT program; PG&E's history

[1813] Ex. 30 (PG&E-7), p. 8-66.

[1814] Ex. 30 (PG&E-7), p. 8-67.

[1815] Id.

and familiarity with similar types of IT programs; the program complexity, including elements such as interfaces with other PG&E programs, number of user and user groups impacted, data exchanges outside of PG&E and changes to PG&E's infrastructure; and the certainty of the line of business requirements for the program at the time the forecast is developed. The result of the evaluation is the forecast project cost that is included in the GRC request.[1816]

PG&E states that most of the IT application development project forecasts included in the GRC are generated by the concept cost estimating tool because most of the projects have not proceeded past the initial stages of the IT project lifecycle as defined by the IT Methodology (discussed in Section C(2)(a) in PG&E-7).[1817]

The Commission should not base PG&E's IT project revenue requirement on PG&E's concept cost estimating tool. As PG&E states in its testimony "the concept cost estimate is the first cost estimate generated for a project and it is necessarily presented as a range of costs, because business requirements and technology solutions are still in the initial planning stage."[1818] Additionally, the funding requested for the IT projects in the GRC are not strictly based on the cost estimating tool. As PG&E provides in its testimony and data response, "the forecast amounts included in the GRC for IT application development projects are based on a combination of the output of the concept estimating tool and PG&E's best professional judgment."[1819] Additionally, unlike the revenue requirement that PG&E will receive for the IT projects, there are no certainties that the IT projects that PG&E requests funding for in this GRC will actually be completed.

As such, DRA recommends that the Commission limit ratepayer funding of IT projects to 86% of PG&E's requested costs for those projects not otherwise opposed by DRA. DRA has determined that for all IT projects forecast by PG&E in its 2011 GRC which relied on the concept cost estimating tool, PG&E only spent 86% of its forecast based on the actual funds expended by PG&E. DRA believes it is appropriate to assume the same level of IT under-spending in this GRC for proposed IT costs in which PG&E relied on the concept cost estimating tool.[1820]

[1816] Id., p. 8-70.

[1817] Id.,

[1818] Id., p. 8-71.

[1819] PG&E data response _DR_DRA_239-Q01.

[1820] Ex. 86 (DRA-18), pp. 66 – 69.

8 HUMAN RESOURCES

PG&E's Human Resources (HR) Testimony is discussed in two parts. One part covers HR policies, such as the goals and strategies that support PG&E's efforts to attract and retain a qualified workforce and the result achieved towards that end, but does not discuss the cost[1821]. HR and Information Technology costs are presented together with corporate service department costs under Administrative and General Expenses[1822].

8.1 Introduction

PG&E is the engine that powers the eight largest economy in the world, with over 15 million customers in a 70,000-square-mile service territory[1823]. On the basis of these facts alone, California ratepayers have consistently paid out some of the highest electricity rates in the country to ensure that PG&E remains the leader it must be in providing safe and reliable service. However, leadership must be reflected in reasonableness and the ability to adjust to changing times and circumstances. PG&E must show leadership in cutting costs where necessary in times of economic hardship and reassuring ratepayers that it holds the public interest above shareholder profits in times of safety crisis.

Ratepayer Confidence in the Company is low now, and restoring that confidence lies squarely on the shoulders of the men and women who make up PG&E's human resources. The Company seems to recognize this fact in the employment of a new Chief Executive Officer, but the new CEO must work with the same human resources, and ratepayers are watching to see how that change at the top would affect them. So far, it has not been reflected in the demands and forecasts for funding PG&E is making in this GRC.

PG&E's total compensation is 9.9 percent above market, but PG&E claims the Commission has recognized that a +/- 10 percent of market variance is a reasonable range. However, the Commission has consistently stated that +/- 5% is the reasonable, but even taking PG&E's position for the sake of argument, 9.9 percent of 10 percent leaves no margin for error

[1821] Ex. 35, PG&E-8

[1822] Ex. 38, PG&E-9.

[1823] Ex. 30 (PG&E-7), p. 1-3.

in the variance calculation[1824]. Further, PG&E employee benefits remain 56.2 percent above those of comparable companies, but PG&E continues to seek an increase that sends the signal to ratepayers that PG&E's workforce may not be satisfied with such high benefits. These signals leave ratepayers to draw their own conclusions about how unreasonable workforce dissatisfaction with benefits translates into recent events surrounding safe and reliable service.

PG&E acknowledges that it "serves one of the most diverse customer bases in the nation" and should have a workforce that reflects the community it serves[1825]. Indeed, one need only hear a public service announcement on a San Francisco public transit repeated in four languages that span all the continents of the world to understand the degree of diversity that PG&E serves. Consequently, workforce diversity should not just focus on costly sensitivity training programs or token racial inclusion that can be dismissed as political correctness of the times, but on hiring policies that show that those at the top belong to the cultures they serve and reflect the gender of their community in a reasonable proportion to the community's statistics. Hiring policies should involve adding leadership at the top whose personal experiences with discrimination inform their understanding of the prejudices in their community.

In all, PG&E's HR seems to recognize these facts and obligations as is evident in its mission statement.

> The mission of Pacific Gas and Electric Company's (PG&E or the Company) Human Resources (HR) Department is to attract, retain and support a qualified, engaged, healthy and diverse workforce to deliver the services that our customers need and expect.[1826]

The Company needs to now put this HR mission to practice at a reasonable cost to ratepayers.

8.2 Workforce Diversity and Inclusion

DRA reviewed PG&E's workforce diversity program to ensure that it meets the expected level of inclusion and consistency that a public utility service should have as a ratepayer funded entity. This review revealed some concerns, but found nothing to take exception with in the

[1824] Ex. 84 (DRA-14), p. 4.

[1825] Ex. 35 (PG&E-8), p. 1-1.

[1826] Ex. 35 (PG&E-8), p. 1-1.

diversity program at this time. PG&E notes that it employs 23,000 men and women[1827] and strives to ensure that this workforce reflects the diverse community the Company serves without compromising the quality and talent that it must have to deliver its services. PG&E maintains that it takes a proactive role in developing the qualified candidates that make up its talent pool with programs such as PowerPathway™ and Bright Minds Scholarships™ which are focused on ensuring that the workforce of the future are prepared when needed and continue to reflect the community's diversity[1828].

The level of PG&E's commitment to workforce diversity is commendable if one accepts PG&E's testimony on its face and there is some substance to the fact that PG&E's description of this commitment captures the essence of workforce diversity.

> PG&E believes that building a workforce that is representative of the diversity of the customer base will strengthen and empower PG&E to anticipate, understand, and respond more effectively to the diverse needs of the 15 million people of the California communities that PG&E serves. An inclusive culture enables diverse perspectives to come together to effectively deliver the gas and electric services customers depend on.[1829]

The percentage of women and minorities at PG&E is higher than the national industry averages[1830] and the largest gains for this class of employees are at the director, manager and professional levels[1831]. However, DRA is concerned that "[t]he percentage of women at the officer level has decreased slightly from the highest points over the past five years."[1832] PG&E does not explain why the percentage of women has dropped but notes that it is monitoring the situation closely and trying to build internal pipelines to develop and source female candidates[1833]. DRA also does not see cause to be alarmed by this statistic at this time, but will continue to monitor the situation to ensure that improvements promised in this rate cycle materialize by the next rate cycle instead of being repeated as another broken promise.

[1827] Ex. 82 (DRA 14).

[1828] Ex. 35 (PG&E-8), p. 1-11.

[1829] Ex. 35 (PG&E-8), p. 2-2.

[1830] Ex. 35 (PG&E-8), p.2-4.

[1831] Id., p. 2-2.

[1832] Ex. 35 (PG&E-8), p. 2-3.

[1833] Id.

8.3 Compensation

The analysis of PG&E's compensation request from a ratemaking policy perspective essentially assesses the competitiveness of PG&E's compensation levels relative to market[1834]. To support this assessment, California utilities and DRA have always conducted Total Compensation Studies (TCS) using an independent consultant to lead and manage the process.

> In PG&E's last GRC, the Commission found that PG&E was not in the best position to independently analyze how its compensation compares to that offered by comparable firms because it has an incentive to underestimate its compensation relative to the market. (D. 95-12-055, 63 CPUC2d 570, 590.) The Commission provided that in the event of another GRC, PG&E would be required to present a study in which independent experts have undertaken all analysis with regard to benchmarks, job matching, and the selection of comparable firms. (*Id.*) PG&E has done so.[1835]

(*Re Pacific Gas and Electric Company*, D.00-02-046[1836], mimeo p. 126.)

However, TCS is not the only yardstick for measuring the competitiveness of executive compensation levels.

> Surveys of other companies, while relevant, are not the only measure in determining whether or not the utility's requested compensation is just and reasonable.[1837]

Consequently, DRA continues to seek ways to improve the study, like moving away from a study that is substantially driven by a survey of individually selected industries and utility companies to a broad based survey and seeking to determine how the result of a TCS would change if employees paid-time-off are considered separately from the study.

8.3.1 Total Compensation Study

> Total Compensation for this study is defined as annual cash compensation (base salary and short-term incentives) plus the value of employee benefits. The methodology examines cash compensation and employee

[1834] D.04-05-055, mimeo p.13

[1835] D.00-02-055, mimeo, p. 126

[1836] 99 P.U.R.4th 177

[1837] D.04-05-055, mimeo, p. 113.

> benefits separately and then combines the values to obtain total compensation.[1838]

DRA and PG&E jointly selected the compensation and benefits firm, Mercer, to be the lead and manage the TCS in this proceeding[1839]. Mercer performed the TCS using PG&E's own company demographic and economic assumptions whenever possible. In a departure from previous surveys done for the study and mostly at DRA's urging, "Mercer also used broad based compensation survey results rather than using a survey of selected industries and utility companies."[1840]

> The TCS results revealed that PG&E's total compensation was 9.9% above market, with base salaries 5.5% above market, total cash compensation 0.7% above, and benefits 56.2% above market. PG&E (and Mercer[1841]) assert that the total 9.9% is a reasonable variance as it is within +/- 10% of market.[1842]

PG&E claims that in its last fully litigated case[1843], the Commission held that a 10 percent variance was reasonable for the utility[1844]. However, what the Commission said in that decision was:

> PG&E points to four reasons why it believes the study overstates the extent to which its total compensation exceeds the surveyed group. These are California's higher labor costs, the degree of unionization, company size, and employee experience and turnover. <u>The record evidence shows that</u> PG&E's compensation practices result in its paying its employees 7.23% more on a weighted average basis than the compensation calculated for comparable firms. We find merit in PG&E's and IBEW's arguments that support a differential of this level.[1845]

[1838] Ex. 35 (PG&E-8), p. 4-7.

[1839] Ex. 82 (DRA-14), p. 4.

[1840] <u>Id.</u>

[1841] As part of the study, Mercer was not directed to provide an opinion regarding the variance of PG&E to market, only to calculate what that variance is. Ex. PG&E-8, p. WP 4-4 details Mercer's role and responsibilities.

[1842] Ex. 35(PG&E-8), pp. 3-8 and 4-11.

[1843] Subsequent cases have resulted in settlements between the parties.

[1844] Ex. 35 (PG&E-8), p. 2-1.

[1845] D.00-04-046, mimeo, p. 126, emphasis added.

In this proceeding, PG&E has not pointed to any evidence to support the argument that a 10 percent variance is reasonable on the facts of this case or the elements of the TCS. The conditions that existed in 2000, when the Commission found a 7.3 percent variance acceptable, did not exist in the current survey. In fact, subsequent TCS surveys corrected those mistakes in methodology.[1846] In more recent cases, the Commission has stated that 5 percent variance should be the basis for a reasonable compensation level.[1847]

DRA recommends that the Commission bring PG&E's compensation within the 5% level and calculated this level for all PG&E employees as follows:

> Table 14-2 below summarizes DRA's calculation of the amount of adjustments necessary due to the excessive HR compensation revealed by the TCS. The total compensation of the benchmarked positions and the percentage of benchmarked employees were used to calculate a potential total compensation for all PG&E employees.[1848] The percentage by which PG&E is over market was applied to the potential total compensation to calculate an approximate dollar amount by which PG&E's total compensation is over market. DRA recommends $85.527 million of adjustments to the forecasted costs of programs in this exhibit, and $84.634 million of adjustments to PG&E's Short-Term Incentive Program in Exhibit DRA-15. The totality of DRA's adjustments would bring PG&E's total compensation to within the CPUC's acceptable 5%

[1846] Ex. 82 (DRA-14), p. 5.

[1847] Id., footnotes 13-17, citing:

Application of Pacific Gas and Electric Company (2000) 4 CPUC 3d 315, 429; D.00-02-046.

D.09-03-025, p. 127. SCE's Total Compensation "…study results indicate that the compensation levels sought by SCE are generally at market, with the overall compensation level 0.9% above market levels, well within the margin of error assumed by the Commission for these studies of + / - 5%."

D.04-07-022, p. 205: "Since SCE's total compensation is shown to be 4.3% above the comparable market total compensation, and the study margin of error is plus or minus 5%, we conclude that SCE's total compensation for all employees is equivalent to the market level."

D.07-03-044, p. 157: "PG&E's total compensation is 4.71% above the survey average… No party disputed the reasonableness of PG&E's total compensation."

A.10-12-005/006, Exh. SDG&E-25, Appendix I, Total Compensation Study, p. 4. SDG&E's total compensation was found to be 3.4% above market.

A.10-12-005/006, Exh. SCG-19, Appendix I, Total Compensation Study, p. 4. SCG's total compensation was found to be 3.2% above market.

[1848] This calculation is necessary because the TCS does not include a total compensation figure for any non-benchmarked employees, only for those employees whose compensation was benchmarked.

> variance. In the event the Commission does not adopt DRA's specific line item adjustments, DRA recommends a "global" adjustment of an amount that would bring PG&E's overall total compensation to within the acceptable 5% variance.

Human Resources
Calculation of the Amount Total Compensation is 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, p. 4-11.[1849]

A closer review of the individual categories that make up the executive compensation survey illustrates the need to make this adjustment. Holding the executive compensation at the junior levels constant, or even lowering or creating a junior level of executives for that purpose, would allow top executives to increase their compensation levels far above the variance while keeping the total levels within the variance. Thus PG&E argues:

> PG&E's compensation should be evaluated on an aggregate total compensation basis. Indeed, as explained above, it is the only basis on which the Study provides evidence to assess the reasonableness of the compensation offered by PG&E. Consistent with prior studies, this Study does not judge the competitiveness of any individual job classification, nor of any component of PG&E's total compensation package.[1850]

The Commission has never established a fixed or rigid rule that constitutes "the only basis on which the [Total Compensation] Study provides evidence to assess the reasonableness of compensation offered by [the utilities]". As noted in DRA's testimony, , the last GRC resulted in Long-Term Incentive Program (LTIP) payouts being removed from the TCS as a result of a settlement between PG&E[1851] and this TCS departed from the prior practice of

[1849] Ex. 82 (DRA-14), p. 6.

[1850] Ex. 35 (PG&E-8), p. 38.

[1851] Ex. 82 (DRA-14), p. 7.

surveying only a select group of general industries and utility companies[1852]. The TCS will only continue to be helpful if it is dynamic and allows what is gained through experience to inform the development of future TCS processes.

"Surveys of other companies, while relevant, are not the only measure …" This means that information provided in the courses of the TCS should be used in any way that informs the process regardless of whether that usage fits one party's view of how a "traditional" TCS is run, especially when it does not interfere with doing a "traditional" TCS concurrently.

Therefore, DRA recommends that the Commission adopt its adjustment of the total compensation to bring it down to with the CPUC's acceptable 5 percent or approve a "global" adjustment that would bring PG&E's total compensation to within the acceptable variance.

8.3.1.1. Long Term Incentive Program

DRA tried to analyze PG&E's Long-Term Incentive Program (LTIP) payouts for recent years, and conducted discovery to obtain the information from PG&E. PG&E refused to provide DRA with its LTIP payouts. PG&E argued that because the Commission approved the parties' agreement to discontinue including long-term incentives in future compensation studies, the LTIP is beyond the scope of the TCS.

However, PG&E claimed that the information in its General Order (GO) 77-M Report is a reasonable proxy for the recent payout information. PG&E's GO 77-M Report is not a proxy for anything.

> The GO 77-M report may or may not show complete information about LTIP; it includes only "officers," defined as being at the Vice President level and above, and "non-officers with a base salary of $250,000 or more."[1853] In discussions during the TCS process, PG&E stated that some employees at the Director and Senior Director levels are eligible for certain executive benefits. At PG&E, Directors and Senior Directors are not officers, but are in leadership positions with responsibility for overseeing the work of a unit of the company.[1854] There are 243 employees at the Director and Senior Director levels,[1855] who earn an

[1852] Id., p.4.

[1853] "Report of Pacific Gas and Electric Company Pursuant to General Order No. 77-M For the Year Ended December 31, 2011," Attachment A.

[1854] Ex. PG&E-8, p. 4-21.

[1855] Ex. PG&E-8, p. 4-11.

> average base salary of $180,000[1856] which is below the $250,000 base salary cut-off of the GO 77-M report, and who may or may not be receiving LTIP. For this reason, the GO 77-M report is not an appropriate proxy for the information requested in Data Request DRA-114, Q.2.[1857]

The TCS is not a basis for excluding any discoverable information from a GRC by any form of posturing. DRA should able to conduct discovery about the LTIP in the course of a GRC whether DRA wants to use it for a TCS or simply to see how it correlates to other benefits to inform the proceeding.

> In 2009, the LTIP payout (as recorded in the GO 77-M report) was $16.6 million.[1858] In 2011, the first year in which LTIP was not considered in a compensation study, the LTIP payout reported on the GO 77-M report nearly tripled to over $40 million. Incentive pay should be identified in future compensation studies, both for consistency between the large investor-owned utilities within California,[1859] and also for transparency. Incentive pay is a component of employees' total compensation package. DRA recommends that the Commission direct PG&E to resume including LTIP payouts in the utility's future Total Compensation Studies, beginning with PG&E's next GRC.[1860]

8.3.1.2 Paid Time Off

DRA also sought to discover how Paid-time-off, such as vacation, sick leave, holidays, and flex days, could inform the TCS if they were valued separately. PG&E refused to let this issue be considered in the TCS either.

> Paid time off (PTO) such as vacation, sick leave, holidays, and flex days, has never before been valued as a benefit in a CPUC-ordered TCS. This is because the time off is generally assumed to be included in an employee's base pay. While this is technically correct, it ignores two facts: that PTO is a valuable benefit to the employee and that there can be an actual cost to the company. If two companies offer the same job for the same pay, and one offers two weeks of PTO while the other offers four weeks of PTO,

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[1856] Ex.35 (PG&E-8), p. 4-82.

[1857] Ex. 82 (DRA-14), p. 7.

[1858] "Report of Pacific Gas and Electric Company Pursuant to General Order No. 77-M For the Year Ended December 31, 2011," Attachment A.

[1859] Southern California Edison, San Diego Gas and Electric Company, and Southern California Gas Company all include LTIP in their TCS.

[1860] Ex. 82 (DRA-14), p. 8.

> the second company provides a better value to its employees. A company incurs actual costs from needing to replace the employee who is using PTO either with other employees working overtime or with a temporary replacement, or the company loses money from lost productivity. In California, when an employee leaves a company, the employee must be paid in cash for any unused vacation.[1861]
>
> Mercer and PG&E agreed to value PTO in this TCS and present it as additional information in an appendix. The PTO valuation was not presented in the TCS in the way DRA was expecting; the appendix shows a total of all benefits *including PTO*.[1862] When the total amount of all benefits including PTO, $500,451,891, is subtracted from the "in-study" benefits amount of $321,197,079,[1863] the result shows that the value of the PTO that PG&E is providing to the bench-marked employees is over $179 million. Compared to the total compensation for the bench-marked employees, the PTO amount as a benefit adds 13.15% of additional value for the bench-marked employees.[1864] The bench-marked employees comprise 54% of the PG&E employee population[1865] so the overall value of PTO provided to all PG&E employees could exceed $330 million above the total compensation paid by the company and, yet, PTO was not valued as a benefit in the TCS. DRA recommends that the Commission require PTO to be included in future TCS as a valued employee benefit.[1866]

PG&E argues that "[i]n order to compare this value [PTO] to the marketplace, an additional survey or data collection effort would have to be undertaken…[which] would increase the complexity and cost of the TCS."[1867] Leaving aside the interesting notion that PG&E is using the cost to ratepayers to prevent a study that seeks to evaluated its executive compensation, the notion that the PTO value is not useful unless it is separately compared to the market place, makes PG&E the witness, judge and executioner of all things TCS. It is evidence that DRA

[1861] California Department of Labor Relations, Division of Labor Standards Enforcement, http://www.dir.ca.gov/dlse/faq_vacation.htm

[1862] Ex. 35 (PG&E-8), p. 4-71.

[1863] Ex. 35 (PG&E-8), p. 4-11.

[1864] Total PTO for bench-marked positions: $179,254,812. Total aggregate compensation for bench-marked positions: $1,362,892,424. $179,254,812 divided by $1,362,892,424 equals 13.15%.

[1865] Ex. 35 (PG&E-8), p. 4-16.

[1866] Ex. 82 (DRA-14), pp. 8-9.

[1867] Ex. 35 (PG&E-8), p.3-8.

seeks and the weight to give that evidence lies with the Commission not with PG&E, or Mercer, for that matter. The fact that both Mercer and PG&E can include the information that DRA requested in an appendix means that they can equally include the information in the TCS and should have done so.

MERCER submitting a joint rebuttal with PG&E to to include PTO values in the TCS because it is inconsistent with the role that the Commission intended the independent study experts to play. In PG&E's rebuttal to DRA's HR testimony, Mercer sponsored a Chapter stating that:

> PG&E has asked Mercer to provide our opinion regarding how PTO benefits are typically valued in similar studies and any recommendations that Mercer has for the Commission on how, or if PTO should be included in future Total Compensation Studies.[1868]

First, DRA was not privy to any discussions between PG&E and Mercer about Mercer testifying on behalf of any party in this proceeding. Secondly, Mercer was retained to offer its opinion only on the TCS study for the 2014 GRC, not on all future rate proceedings. Mercer's own description of the roles the parties are supposed to play in the TCS process belies its participation in this proceeding as a PG&E witness are as follows:.

- The approach for conducting the study and reporting the results involved representatives from PG&E, DRA and Mercer working together as a study team ("Study Team"

  – Mercer: Lead and project manage the benchmark study, prepare materials necessary for review by the Study Team to be able to complete each project step, provide expert opinion and recommendations for benchmarking methodology/approach, conduct necessary data collection, conduct all benchmarking data analysis and develop the report of study findings.[1869]

Nothing in Mercer's own description of its role supports Mercer giving an opinion except "for benchmarking methodology/approach", much less sponsoring PG&E's testimony. The whole point of using Mercer in the study is to ensure the independence of the process not to

[1868] Ex. 35 (PG&E-8), p. 4-1.

[1869] Ex. 35 (PG&E-8), p. 4-4.

supply PG&E with a paid ally[1870]. At the very least, Mercer had the obligation to consult DRA before playing any part in sponsoring PG&E's testimony or even offering any opinions as to what the reasonable variance of executive compensation should be.

It is not too late to correct these measures, especially in light of another utility rate case already in process. Mercer can still return to the drawing board to consider PTO and LTIP in the study submitting the result of the study to the parties. In SCE's last GRC, the Commission ordered SCE and DRA to meet with any other interested parties, within 60 days of the issuance of the decision, to consider ways to make the TCS better.

8.3.2 Short-Term Incentive Plan

PG&E describes its Short-term Incentive Plan (STIP) as an annual variable incentive pay plan used to attract, retain, and motivate qualified professionals to work for the Company[1871]. The STIP is variable because it is dependent on individual performance and the Company's achievement of specific performance goals measured over a Plan Year[1872]. As such, it can be used to align the motivation of an individual employee with important Company objectives and customer interests[1873]. PG&E claims that STIPs are generally more cost effective than base-pay equivalent compensation and consistent with market practice for professional and managerial employees.

The components of PG&E's STIP are: (1) a Target Payout; (2) Actual STIP Cost; (3) Company Performance Score; and (3) 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[1874]. PG&E establishes a percentage rate for each eligible employee's earning as the target participation rate for that employee and if the Company meets particular performance targets, PG&E pays eligible employees a STIP payout by multiplying their eligible earnings by their target participation rates[1875]. The Company Performance Score is

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[1870] *Re Pacific Gas and Electric Company*, D.00-02-046 mimeo, p. 126.

[1871] Ex. 35 (PG&E-8), p. -1.

[1872] Id.

[1873] Id.

[1874] Ex. 35 (PG&E-8), p. 5-5.

[1875] Id., p. 5-6.

a series of performance goals set by the Compensation Committee of the Board of Directors, which also approves STIP each year[1876]. Regarding the Company Score DRA's Report noted:

> PG&E states, "The company score is a multiplier that the Company applies to all individual awards. If the overall company score is 0.000, then no one receives an incentive award and the total STIP payout for that year is $0.00",[1877] despite the performance on the business performance measures. An example of PG&E's company score being recorded as $0.00 for some employees was during PG&E's Plan Year 2010. PG&E's Board of Directors[1878] awarded zero STIP to officers of the company even though PG&E collected in rates authorized funding for its STIP.[1879]

PG&E requests $130.206 million for the Company's TY 2014 STIP and $107,000 for PG&E Corporation's TY 2014 STIP. This forecast includes a $15.9 million adjustment for additional employees PG&E proposes to hire and a reduction of $231,000 for PG&E Corporation employees[1880]. PG&E claims that 70 percent of its current STIP metrics is focused on safety and customer satisfaction with Company services, while the remaining 30 percent is based on its Earnings From Operations (EFO) metric. Prior to 2012, EFO constituted 50 percent of the STIP metrics[1881] In 2011, PG&E's STIP Target Payout was $100.057 million for the Company and $309,000 for the Corporation and PG&E escalated these figures by $114.3 million for the Company and $337,000 for PG&E Corporation to forecast its TY 2014 STIP Target Payout[1882].

DRA reviewed PG&E's STIP testimony, workpapers, and PG&E's responses to DRA's Master Data Request, and further requested information on PG&E's authorized STIP for the Company and for PG&E Corporation[1883]. This review found that PG&E was inappropriately

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[1876] Id.

[1877] PG&E's response to DRA's Master Data Request, Chapter 8, Q. 6.

[1878] PG&E states its "Committee (and with respect to awards for certain officers, the respective Board of Directors of PG&E Corporation or the Utility) has discretion to reduce or eliminate the amount of final STIP awards notwithstanding the achievement of the specified STIP goals". PG&E's response to DRA's Master Data Request Chapter 8.

[1879] Ex. 83 (DRA-15), p. 3 citing PG&E's response to DRA's Master Data Request Chapter 8, Q.7.

[1880] Ex. 83 (DRA-15), p. 4.

[1881] Ex. 35 (PG&E-8), pp.5-4 to 5-5.

[1882] Ex. 83 (DRA-15), p. 5.

[1883] Id., p. 5.

requesting that ratepayers fund 100 percent of its Target STIP costs[1884]. The Commission has long since held that ratepayers are only responsible for 50 percent of targeted STIP incentives for PG&E's employees.

In D.00-02-046, the Commission stated:

> We find no compelling evidence for a change in our current practice of allowing 50% recovery of targeted incentives from ratepayers. As we have held, shareholders 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. Although PG&E paid out just 72.5% of its target payout during the five years ending with 1996, it paid out nearly 100% of targeted costs over a ten year period. This affirms PG&E's contention that it is reasonable to base estimated payouts on an expected PIP score of 1.0. Accordingly, while we adopt Enron's proposal for equal sharing of PIP expenses, we provide that PG&E is entitled to recover 50% of its estimated payout of $26.5 million, which reflects a PIP performance score of 1.0.[1885]

(D.00-02-046, mimeo, p.256.)

In a recent decision, the Commission reaffirmed this practice of equal sharing of STIP incentives between ratepayers and shareholders and noted:

> In our decision today, we are not recommending reduced compensation for executive officers. We are merely assigning certain costs to shareholders based on what is just and reasonable to assign to ratepayers.

Therefore, DRA estimated its STIP forecast as 50 percent of PG&E's Test Year request after subtracting the 30 percent Financial/ EFO component which only benefits shareholders.

[1884] Id., p.10.

[1885] D.12-11-051, mimeo, p. 450. *Decision on Test Year 2012 General Rate Case for Southern California Edison Company* (2012).

DRA recommends $45.572 million TY 2014 STIP for PG&E and $37,000 for PG&E Corporation.

> DRA's estimate removes 30% of PG&E's forecast measure for Financial/ EFO that does not benefit ratepayers and therefore should be funded entirely by PG&E's shareholders.[1886] DRA's STIP estimate includes equal sharing of the forecast STIP costs between ratepayers and shareholders for measures relating to Safety (Public Safety weighted 24% and Employee Safety weighted 16%) and Customer Satisfaction which provides benefits to both.
>
> PG&E states that its "EFO provides a measure that allows investors to compare the underlying financial performance of the business from one period to another, exclusive of items ('items impacting comparability') that management believes do not reflect the normal course of operations".[1887] An example of an item that impacted PG&E's EFO comparability was expenses incurred to recover from PG&E's San Bruno accident.[1888]

Table 15-6, below, shows DRA's proposed weightings on PG&E's STIP measures for ratepayers and shareholders.

DRA's Proposed Weightings on PG&E's Measures included in STIP[1889]

PG&E's Operational and Financial Measures	**Ratepayers**	**Shareholders**
Customer Satisfaction	15%	15%
Safety (Public and Employee safety)	20%	20%
Earnings From Operations	0%	30%
Total	**35%**	**65%**

[1886] PG&E's 2011 Target STIP Payout was $100.366 million. PG&E's Actual STIP Payout for 2011 was $60.862 million. PG&E did not meet its 2011 Earnings From Operations target that was weighted 50% of STIP. PG&E states "Results are attributable to higher emergency response costs, lower gas transmission revenue, and higher litigation and regulatory matters costs. PG&E Corporation lowered guidance for earnings from operations to the range of $3.45 to 3.60 per share for 2011. Despite the change in guidance, the EFO target was not changed". (DRA-PG&E-219-TLG Q. 1).

[1887] DRA-PG&E-219-TLG Q. 2.

[1888] PG&E's response to DRA-PG&E-219-TLG Q.2.

[1889] Ex. 83 (DRA-15), pp. 9-10.

> As shown in Table 15-6, above, PG&E's EFO is weighted 30% of the STIP payout. PG&E states that its EFO measures PG&E Corporation's earning power from ongoing core operations and that this measure supports its goal of rewarding its shareholders with a focus to deliver on budget, on plan, and on purpose.[1890] Since the main objective and beneficiary of PG&E's EFO goal, that is weighted 30% of the STIP award, is to reward shareholders and relates to earnings per share from operations, PG&E's shareholders should fund this measure at 100%.[1891]

PG&E's actual STIP Payout has exceeded its Target STIP Payout for eight of the last ten years (2003-2012).

Table 15-3
PG&E's Target and Actual Short-Term Incentive Plan Payouts for Non-Officers for 2003-2012[1892]

Plan Year[1893] (a)	Target STIP Payout ($ millions) (b)	Actual STIP Payout ($ millions) (c)	Amount Target STIP>Actual STIP (d)=b-c)
2003	$54.0	$89.2	($35.2)
2004	$55.8	$74.4	($18.6)
2005	$58.3	$78.7	($20.4)
2006	$60.7	$85.3	($24.6)
2007	$76.6	$94.5	($17.9)
2008	$81.1	$99.1	($18.0)
2009	$88.9	$148.3	($59.4)
2010	$91.9	$81.2	$10.7
2011	$100.3	$60.8	$39.5
2012	$109.2	$149.7	($40.5)

[1890] DRA-PG&E-219-TLG Q. 2.

[1891] Ex. 83 (DRA-15), p. 16.

[1892] DRA-PG&E-230-TLG Q.1.

[1893] PG&E's STIP payout to employees is in the following year of the Plan Year (i.e., 2012 STIP Plan Year payout was in March 2013).

From 2003-2009 and in 2012 PG&E's actual STIP Score (STIP Payout Score) exceeded the 1.0, which means that PG&E, its employees and business units exceeded operating objectives during those years. However, in 2010 and 2011, PG&E's Actual STIP Payout was less than the Target STIP Payout. PG&E did not provide the information to explain what contributed to the Actual STIP Payout exceeding the target other than pointing to variations in STIP participants and associated income. There was no evidence that additional work in excess of normal, on-going and routine responsibilities caused PG&E's Actual STIP Payouts to exceed its Target STIP Payout for eight years.1894

Furthermore:

> The years in which PG&E's Actual STIP Payout exceeded its relatively high Target STIP Payout, coincide with years in which PG&E appears to have deferred maintenance on several critical gas and electric projects resulting in poor customer safety and reliability events (i.e., San Bruno explosion, recordkeeping and document management deficiencies).

When pressed further to provide additional information on its STIP increases during the historical period, PG&E only stated:

> As described in the STIP testimony in Exhibit 8 Chapter 5, the STIP Company Score determines the Actual STIP Payout amount each year. The STIP Company Score varies from one year to another based on the company's performance compared to metrics established at the beginning of each year. Below are the STIP Company Scores from 2008 through 2012.
>
> In addition to changes in the STIP Company Score, there are inflationary factors that impact STIP payments, such as salary growth and headcount growth (see Workpapers W-4).
> The difference in STIP payout between 2008 and 2009 is due primarily to the difference in the Company Score of 1.178 for 2008 and 1.648 for 2009. Details of the 2008 STIP Company Score are included in attachment GRC2014-Phl_DR_DRA_219-Q02Atch01. Details of the 2009 STIP Company Score are included in attachment GRC2014-Phl_DR_DRA_219-Q02Atch02.
>
> The difference in STIP payout between 2009 and 2010 is due primarily to the difference in the Company Score of 1.648 for 2009 and 0.864 for 2010. Details of the 2009 STIP Company Score are included in

1894 See Ex. 83, DRA-15, p.14

> attachment GRC2014-Phl_DR_DRA_219-Q02Atch02. Details of the 2010 STIP Company Score are included in attachment GRC2014-Phl_DR_DRA_219-Q02Atch03.
>
> The difference in STIP payout between 2010 and 2011 is due primarily to the difference in the Company Score of 0.864 for 2010 and 0.607 for 2011. Details of the 2010 STIP Company Score are included in attachment GRC2014-Phl_DR_DRA_219-Q02Atch03. Details of the 2011 STIP Company Score are included in attachment GRC2014-Phl_DR_DRA_219-Q02Atch04.[1895]

This explanation fails to add clarity to any understanding of how PG&E's Compensation Committee of the Board of Directors approves STIP Payouts that year after year exceed the set Target.

In D.00-02-046, the Commission stated:

> 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.[1896]

PG&E circumvents the unacceptable risk that formed the basis for the Commission splitting responsibility for STIPs equally between shareholders and ratepayers if the Commission allows it to collect requested payouts without understanding the rationale that supports the Compensation Committee of its Board of Directors to approve STIP Payouts that year after year exceed the Target STIP even when employees do not perform well. DRA's recommendation presents the most compelling argument for avoiding such overcollection, for instance, by ensuring that metrics like EFO are not charged to ratepayers

In this GRC, PG&E seeks ratepayer funding for cash and non-cash rewards and employee recognition expenses. PG&E indicated that it did not specifically forecast the amount of rewards and recognition expenses embedded in its 2014 revenue requirement request. According to PG&E, it recorded $7.031 million of GRC-related cash and non-cash rewards and recognition expenses in 2011; PG&E escalated its 2011 actual expenses by 3% per year for three years, to

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[1895] Ex. 83 (DRA-15), p. 17-18.

[1896] D.00-02-046, p. 256.

estimate that it has included $7.683 million of rewards and recognition expenses in the 2014 GRC forecast.[1897]

Upon further discovery, DRA learned that PG&E recorded $8.232 million of GRC-related cash and non-cash rewards and recognition expenses in 2012.[1898] Using the 2012 recorded figure as the starting point, and escalating it by 3% per year for two years, yields an estimate of $8.734 million of GRC-related rewards and recognition expenses for 2014.

In prior GRCs, DRA has argued that: (1) employee recognition programs provide no clear or identifiable benefit to ratepayers and are not necessary to operate the utility business; and (2) it is inappropriate for ratepayers to be burdened with the responsibility of subsidizing employee recognition programs that are not necessary or required for utility operations.

DRA's testimony in PG&E's 2011 GRC (A.09-12-020)[1899] cites several examples where the Commission has found that expenses for cash and non-cash employee recognition rewards fit the category of social activities and should not be funded by ratepayers.[1900]

After DRA submitted its testimony in this GRC, the Commission issued its decision in the TY 2012 Sempra Utilities GRC. PG&E cites that decision in its Rebuttal saying that the Commission has found programs similar to PG&E's to be "a reasonable ratepayer expense."[1901]

When the Commission authorized ratepayer funding for the Sempra Utilities' programs, it noted "… the *modest* cost of these two programs."[1902] In the TY 2012 Sempra GRC, SoCalGas requested a total of $1.409 million (in 2009$)[1903], roughly 0.2% of SoCalGas' base year labor expense.[1904] SDG&E requested a total of $1.774 million (in 2009$),[1905] roughly 0.33%

[1897] See Ex. 69 (DRA-1), Appendix 1 (PG&E's response to DRA Oral Data Request 16).

[1898] See Ex. 69 (DRA-1), Appendix 1 (PG&E's response to data request DRA-PG&E-145-CKT).

[1899] See Ex. 69 (DRA-1), Appendix 1 (A.09-12-020, Ex. DRA-14, pp. 17-18).

[1900] *See, e.g.* D.09-03-025, D.06-05-016, D.05-04-037, D.04-07-022, D.96-01-011, D.93-12-043, and D.89-12-157.

[1901] Ex. 62 (PG&E-23), p. 6-14, citing D.13-05-010, p. 884.

[1902] D.13-05-010, p. 884, emphasis added.

[1903] Ex. 257 (PG&E Responses to DRA_274).

[1904] 23 RT 2882, Lowe/PG&E.

[1905] Ex. 257.

of its base year labor expense.[1906] PG&E is seeking $7.683 million, or roughly 0.7% of its 2011 recorded adjusted labor expense.[1907] Thus both in dollar amounts and percentage of labor expense, PG&E's program is not the "modest" one approved by the Commission for the Sempra Utilities.

DRA continues to recommend zero ratepayer funding for the expenses for PG&E's Rewards and Recognition program.[1908] If PG&E wants to provide these benefits to its employees, it can do so at its shareholders' expense.

8.3.3 Labor Escalation

DRA discusses its labor escalation in Exhibit 72 (DRA-4).[1909] The Commission has set labor escalation rates in GRCs generally based on forecasted factors.[1910] While the Commission Rate Case Plan allows utilities to update its labor escalation rates, the Commission has held that the updates must be reasonable.[1911] Labor escalation rates determine what ratepayers will pay for regulated utilities' labor costs.[1912]

In the instant GRC, PG&E developed labor escalation rates for Nuclear Production, Hydro Production, Electric Distribution, Gas Distribution Plant and Common Plant.[1913] The main differences between DRA's and PG&E's labor and non-labor escalation rates forecasts are due to PG&E's decision to use surveys it has not previously used to forecast management wage increases.[1914] The Commission has previously used labor agreements to forecast management wage increases.[1915]

[1906] 23 RT 2882, Lowe/PG&E.

[1907] Ex. 256.

[1908] For modeling purposes, this is reflected as an "Other Adjustment" in DRA's Results of Operations model.

[1909] Please note that Exhibit 72 addresses labor, non-labor, and capital related cost escalation. The non-labor and capital related cost escalations are discussed in section 10 below.

[1910] D.10-06-048, 2010 Cal. PUC LEXIS 234 (Cal. PUC 2010), Finding of Fact (FOF) # 15.

[1911] D.09-03-025, p. 483.

[1912] Ex. 72 (DRA-4), p. 1.

[1913] Id.

[1914] Id.

[1915] D.13-05-010, p. 210.

The following table compares PG&E's annual labor escalation with that DRA's[1916]:

Comparison of DRA's and PG&E's Forecasts of 2012-2014 Labor Annual Escalation Rates

Description	DRA Recommended			PG&E Proposed[1917]		
	2012	2013	2014	2012	2013	2014
Labor	2.61%	2.61%	2.61%	2.79%	2.79%	2.79%

PG&E's methodology overstates labor escalation and should not be adopted. For the reasons set forth below, DRA recommends labor escalation rates of 2.61% for 2012, 2013, and TY 2014. **PG&E's Methodology**

PG&E's historic and forecast labor escalation rates are based on weighted average wage and salary increases for PG&E's major employment categories: (1) bargaining units; (2) clerical; and (3) management/administrative and technical (A&T). PG&E says that: "The bargaining unit is comprised of International Brotherhood of Electric Workers (IBEW)-represented employees, Engineers and Scientists of California (ESC) represented employees, and SEIUI-represented employees. The manager/supervisor group is comprised of all supervisory employees (e.g. those classified as supervisors, managers superintendents, or directors) as well as non-supervisor professional, administrative and technical employees."[1918]

For union-represented employees, PG&E is proposing to use labor escalation rates presented in its most recent collective bargaining agreement for the years 2012 to 2014. The labor escalation rates for non-union employees are targeted at 3 percent.[1919] The following table presents a summary by job category of PG&E's proposed labor escalation rates.[1920] PG&E's composite labor escalation rate is a weighted average of the escalation rates for union-represented and non-union represented employees. PG&E proposes to apply all of these wage increases to the forecast period 2012-2014 as well as the attrition years 2015 and 2016.

[1916] Ex. 72 (DRA-4), p. 2.

[1917] Ex. 43 (PG&E-10), p. 3-1.

[1918] Ex. 42 (PG&E-10), p. 3-2.

[1919] Ex. 35 (PG&E 8), Chapter 5, Short-Term Incentive Plan and Labor Escalation Assumptions, p. 5-11.

[1920] Ex. 72 (DRA-4), p. 4.

BARGAINING			NON-BARGAINING		
JOB	Escalation	Count	JOB	Escalation	Count
IBEW	2.75%	8619	Executive	3.0%	37
Hiring Hall:IBEW Phy	2.75%	484	SEIU	3.0%	275
ESC	2.75%	2360	PL1	3.0%	5770
Hiring Hall:ESC	2.75%	210	PL2	3.0%	1051
Hiring Hall:IBEW Clerical	2.0%	112	PL3	3.0%	262
IBEW:IBEW Clerical	2.0%	2622	Lawyer	3.0%	85
			A&T	3.0%	592
TOTAL COUNT		14407	TOTAL	COUNT	8072

PG&E's 2012-2014 Forecasts of Labor Escalation (Table)

PG&E's escalation rates for bargaining employees are lower than that of non-bargaining employees, such as executives, but both labor escalation rates are higher than reasonable. PG&E justifies having higher labor escalation rates for Management/ Administrative and Technical employees than for bargaining employees as follows:

For the company's management employees (also referred to as non-bargaining employees) merit increase budgets are the mechanism for keeping base wages in line with the external market. On an annual basis, PG&E participates in and receives multiple surveys, which it uses to benchmark wage escalation in northern California as well as the utility industry nationally. These surveys are: WorldatWork Salary Budget Survey, Mercer Pay Practices Survey CompData Salary Increase Survey, and Hewitt U.S. Salary Increase Survey. In recent years these survey have consistently reported merit budget of 3 percent. Based on that information, PG&E has also established its merit budget at 3 percent for its non-bargaining unit employees.[1921]

PG&E has not justified applying a higher escalation rate for its non-union employees. DRA recommends that the Commission apply an across-the- board labor escalation of 2.61%.

DRA recommends that the labor escalation rate be a weighted average of PG&E's union-represented labor escalation rates. This results in an escalation rate of 2.61% for the forecast and

[1921] Ex. 35 (PG&E-8), p. 5-11.

attrition period, as summarized in the following table deriving PG&E labor escalation for 2012-2014[1922]:

Category	Index	Weight	Escalation
Clerical/Physical1	Union Wage	0.180542563	1.02
Clerical/Physical2	Union Wage	0.819457437	1.0275
	Total	1.0000	1.0261

PG&E's proposed labor escalation rates for non-union represented employees in its last rate case were also in line with the wage increases for union represented employees. In SCE's last rate case, the CPUC decided to accept SCE's proposed labor escalation rates that were similarly in line with wage increase for union represented employees.[1923]

In this rate case, PG&E justifies its Management/ Administrative and Technical employees escalation rates by referring to surveys that have not previously been used to forecast management escalation rates for these employees. The surveys refer to "merit" budget increases that may or may not be applicable to public utilities in general, or PG&E in particular. DRA recommends these surveys be given no weight.

DRA's recommendations are conservative. DRA checked its recommendation by comparing it with the results derived by basing its wage increases for the non-union groups from forecasts taken from the IHS Global Insight Power Planner. This methodology is similar to the methodology used by PG&E in its 2007 general rate case.[ii] In the past, the Commission has adopted labor escalation rates that were based on IHS Global.[1924]

Specifically, for managers and supervisors, DRA relies upon the Global Insight Index, (**ECIPWMBFNS**), Employment Cost Index-Managers and Administrators. For the Professional/Technical employee group DRA relies upon the Global Insight Index, (**ECIPWPARNS**), Employment Cost Index – Professional and Technical Workers.[1925] Forecasts of wage increases for these two indexes were taken from the Global Insight Power Planner,

[1922] Ex. 72 (DRA-3), p. 5.

[1923] D.12-11-051, p. LEXIS* 951.

[1924] D.12-11-098, p. LEXIS *898

[1925] Ex. 72 (DRA-4), p. 6.

Fourth Quarter 2012. After applying the weightings, DRA arrives at labor escalation rates of 2.30 percent for 2012, 2.41 percent for 2013, and 2.50 percent for test year 2014. This results in an average of 2.40 percent per year over the period from 2012 to 2014.

DRA's proposed escalation rates of 2.61% for 2012, 2013, and TY 2014 are in fact higher than the Global Insight Power Planner for the same years.

For purposes of calculating attrition increases, PG&E has proposed labor adjustments based on 2015 and 2016 wage rate increases of 2.75% for union (operating units) employees and 2.97% for non-union (A&G) employees, and forecasts company-wide escalation of 2.79% per year for 2014 through 2016.[1926]

The Commission should reject the proposed 2.79% per year wage rate increase. DRA's recommendations for wage escalation rates for 2015 and 2016 are discussed below in Section 12 of this Opening Brief.

8.4 Employee Benefits

8.4.1 Health Plans (including Escalation)

PG&E forecasts $385.071 million for TY Medical Programs expense.[1927] This includes PG&E's health care and prescription coverage plans, legally-required drug testing for certain employees, and an Employee Assistance Program. Projected employee contributions are netted out from the total health benefits cost and are addressed in the particular sections below. DRA generally accepts PG&E's forecast methodology for Medical Programs but DRA's lower estimate for employee population results in a DRA TY 2014 estimate of $350.064 million, an adjustment of $35.006 million.

PG&E currently offers two self-funded plans and two Health Maintenance Organizations (HMO) plans.[1928] Beginning in 2013, PG&E is making several changes to its medical benefits which are intended to improve the quality of care while providing incentives for employees to make healthy choices and lower PG&E's costs by leveraging buying power and streamlining administration. Most notably, the company is moving to a single self-funded Health Account

[1926] Ex. 42 (PG&E-10), p. 3-4, Table 3-2.

[1927] Ex. 37 (PG&E-8 workpapers), p. WP 6-1.

[1928] Ex. 35 (PG&E-8), p. 6-6.

Plan (HAP) which will be administered by Anthem Blue Cross or Kaiser Permanente Insurance Company, depending on the employee's location.

The HAP offers prescription drug coverage and no-cost preventive and primary care services. It has a higher deductible and higher out-of-pocket maximums than the current health plans. It also replaces flat-cost co-payments with co-insurance,[1929] which is where employees are responsible for a set percentage of their health care costs after their deductible has been met. To offset the higher costs to employees, PG&E will fund a Health Account with a set dollar amount ($750 individual coverage and $1,500 for family coverage in the first year; lower in future years) and offer incentives for employees who take a voluntary health screening, regardless of outcome, and who pass a tobacco screening or complete a tobacco cessation program. Some employees will be transferred to the HAP in 2013, and all employees will be covered by it in 2014.[1930]

DRA has reviewed these plan changes and has no related adjustment to PG&E's Medical Programs forecast.[1931]

PG&E uses medical escalation rates proposed by its actuary, Towers Watson of 5.4% for 2012, 6.4% for 2013, and 5.4% for 2014.[1932] DRA accepts these medical escalation rates.[1933]

8.4.1.1 Dental Plans

PG&E forecasts $36.591 million for TY Dental Plans expense.[1934] PG&E offers a self-funded dental plan administered through Delta Dental of California. Employees who choose a Delta Preferred Provider dentist pay the lowest cost while employees who choose a Delta Premier Network dentist or out-of-network dentist have a higher cost-sharing and higher deductible amounts. DRA analyzed the historical expenses for PG&E's Dental Plans expense and does not oppose them. DRA's lower estimate for employee population results in a DRA TY 2014 Dental Plans estimate of $33.265 million, an adjustment of $3.326 million.

[1929] Ex. 35 (PG&E-8), p. 6-26.

[1930] Ex.35 (PG&E-8), pp. 6-6 through 6-8.

[1931] Ex. 82 (DRA-14), p. 13.

[1932] Medical Escalation rates for the Post-Test Years are discussed below in Section 12 of this Opening Brief.

[1933] Ex. 82, p. 12.

[1934] Ex 37 (PG&E-8 workpapers), p. WP 6-2.

8.4.1.2 Vision Plan

PG&E forecasts $3.709 million for TY Vision Plan expense.[1935] PG&E offers one vision plan provided by Vision Service Plan (VSP). Employees can use any provider they choose, but their out-of-pocket costs will be lower if they choose an in-network provider. PG&E is switching from the VSP Signature plan to VSP Choice in 2013 for some employees and by 2014 for all employees. There are no changes to the benefits provided, but this switch saves money for employees and the company because VSP Choice network providers have agreed to a lower fee schedule than VSP Signature providers.[1936] DRA analyzed the historical expenses for PG&E's Vision Plan expense and reviewed the plan changes. DRA does not oppose the base forecast for TY Vision Plan program cost. DRA's lower estimate for employee population results in a DRA TY 2014 estimate of $3.372 million, an adjustment of $337,000.

8.4.1.3 Group Life Insurance

PG&E forecasts $779,000 for TY Group Life Insurance expense.[1937] Currently, PG&E offers all employees basic life insurance coverage of $10,000 through Metropolitan Life Insurance Company. Employees also have the option to purchase supplemental life insurance at the employee's expense. Certain management employees and retirees are also eligible for company-paid accidental death and dismemberment (AD&D) insurance coverage, and have the option of purchasing coverage for their spouses at their own expense.[1938] Beginning in 2013 for some employees and taking effect for all employees in 2014, a number of enhancements are being made to the group life program.

DRA analyzed the historical expenses for PG&E's Group Life Insurance expense and reviewed the plan changes. DRA does not oppose the base forecast for TY Group Life Insurance program cost, but DRA's lower estimate for employee population results in a DRA TY 2014 estimate of $708,000, an adjustment of $71,000.[1939]

[1935] Ex. 37 (PG&E-8 workpapers), p. WP 6-2.

[1936] Ex. 35 (PG&E-8), p. 6-23.

[1937] Ex. 37 (PG&E-8), p. WP 6-2.

[1938] Ex. 35 (PG&E-8), p. 6-24.

[1939] Ex. 82, p. 15.

8.4.1.4 Employee Contributions

Employees contribute to the cost of their health care through payroll deductions for medical and dental premiums, and through paying co-payments, co-insurance, deductibles, and other out-of-pocket costs. The forecast employee contributions were calculated by Towers Watson, assuming the current cost-sharing percentages for union and non-union employees will continue. The current cost-sharing percentage for unionized employees is 7.5% of the premium for medical coverage, and the current cost-sharing percentages for non-union employees is 7.5% of the premium for medical coverage and 7.5% of the premium for dental coverage.[1940]

DRA analyzed PG&E's historical Employee Contributions and reviewed the plan changes. The Kaiser Family Foundation, a leader in health policy analysis, health journalism and communication, and Aon Hewitt, a leading global provider of human resources solutions, are both projecting employee medical care premium contributions in the range of 18% to 28%.[1941, 1942] Towers Watson, the actuarial firm that prepared PG&E's health care forecast, found in its annual employer survey that the average employee share of health care premiums is expected to be 23.8% in 2013.[1943] PG&E has offered no explanation as to why its employees should not be sharing medical care costs at a similar rate as employees at other companies. DRA does not have access to Towers Watson's calculations of PG&E's employee contributions based on enrollment and unionization, so DRA used the following method to estimate its proxy for a projected employee contribution amount.

DRA strove to achieve an employee contribution rate comparable to that recorded by Kaiser Family Foundation, Aon Hewitt, and Towers Watson. This was accomplished by first multiplying the 7.5% employee contribution rate times the 2011 medical plans expense of $291,980, then subtracting that amount ($21,899) from the total employee contribution amount for 2011 ($23,458) to get an estimated dental plans contribution amount of $1,559. This amount

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[1940] Ex. 35 (PG&E-8), p. 6-27.

[1941] http://ehbs.kff.org/?page=charts&id=1&sn=12&p=1

[1942] http://www.prnewswire.com/news-releases-test/average-cost-of-us-health-coverage-per-employee-is-expected-to-cross-the-10000-threshold-for-the-first-time-in-2012-according-to-aon-hewitt-130847468.html

[1943] "18th Annual Towers Watson/National Business Group on Health Employer Survey on Purchasing Value in Health Care," p. 4. http://www.towerswatson.com/en/Insights/IC-Types/Survey-Research-Results/2013/03/Towers-Watson-NBGH-Employer-Survey-on-Value-in-Purchasing-Health-Care

divided into the 2011 dental plans expense ($26,428) estimates a percentage to apply to the dental amount, which is 5.9%. DRA then multiplied the 7.5% medical plans contribution rate and the 5.9% dental contribution rate by a factor of 3.25 and applied these new percentages (24.38% for medical and 19.18% for dental) to the TY 2014 base medical plans forecast and base dental plans forecast, respectively. DRA's total estimated employee contribution equals roughly 23.92% of the total forecasted base expense for these two programs, which is an adjustment of ($68.249) million to the base expense. PG&E forecasted an additional $2.790 million in contributions related to increased headcount. DRA subtracted that amount from its adjustment, so DRA's total adjustment to the TY forecast is ($65.459) million.

DRA uses this figure as a proxy for its 2014 test year forecast of employee contributions. If the Commission does not adopt this adjustment, then DRA proposes a commensurate global adjustment to PG&E's revenue requirement as discussed in Section 8.3, Compensation, of this Opening Brief.

In Rebuttal, PG&E opposes DRA's recommendation to increase employee contributions to medical plans saying that "… PG&E has already taken steps to reduce long term costs of its employee medical and pension plans."[1944] PG&E goes on to say that, if the Commission were to adopt DRA's recommendation increasing employee contributions to 23.92%, PG&E "… would have continued on a path of higher long-term health care costs and less healthy employees…"[1945]

But, in fact, PG&E's long term costs are still increasing, and so is ratepayers' share of them. PG&E's medical trend rate is not going down[1946], and its expenses are "…going up and up and up…."[1947] PG&E is asking for $1,434 per month on average for family coverage. According to a survey PG&E itself cites, monthly premiums for Family Coverage in California in 2012 were $1,386, and were $1,312 nationally.[1948] In 2012, Single Coverage in California averaged $545 a month, and what PG&E is asking ratepayers to pay is "significantly higher than

[1944] Ex. 62 (PG&E-23), p. 1-2, lines 5-6.

[1945] Ex. 62 (PG&E-23), p. 7-3.

[1946] Ex. 336.

[1947] 29 RT 3895, Hunter/ DRA.

[1948] Ex. 332, p. 35 (Survey, p. 2.).

that."[1949] And, while 21% of firms in California reported that they increased workers' share of the premium in 2011, PG&E proposes to maintain its employee's share of premiums at 7.5%. Compare this to the average percentage premium paid by Transportation/ Communications/Utilities employees nationwide of 20% for Single Coverage, and 26% for Family Coverage.[1950] And it is all for a plan that is not very good from an PG&E employee perspective, and certainly not from a PG&E ratepayer perspective.[1951]

For all of these reasons, DRA continues to recommend the Commission make an adjustment of ($68.249) million to the base expense, or an adjustment of ($65,459 million) once DRA's recommended decrease in FTE count is factored in. If this recommendation is not adopted, then DRA recommends a global adjustment to PG&E's revenue requirement as discussed in the Compensation section, above.

8.4.2 Retirement

DRA does not oppose PG&E's forecasts for post-retirement medical, post-retirement medical trust contributions, post-retirement life insurance, or post-retirement life insurance trust contributions.[1952]

8.4.3 Disability

DRA does not oppose PG&E's forecasts for long-term disability and leave administration and long-term disability trust contributions.[1953]

8.4.4 401(k) Funding

PG&E forecasts $85.779 million for TY 401(k) Retirement Savings Plan (RSP) expense.[1954] PG&E's forecast was calculated by Towers Watson which used PG&E's actual 2011 demographics for match rate, opt-out rate, and contribution rate.[1955]

[1949] 29 RT 3888, Hunter/DRA.

[1950] Ex. 261 (Kaiser Survey), p. 97.

[1951] See 29 RT 3895, lines 18-21. Hunter/DRA.

[1952] Ex. 82 (DRA-4), p. 20, Table 14-12.

[1953] Ex. 82 (DRA-4), p. 20, Table 14-12

[1954] Ex. 37 (PG&E-8 workpapers), p. WP 7-1.

[1955] Ex. 37 (PG&E-8 workpapers), p. WP 7-13.

PG&E projects a significant increase to this program expense due to major changes in the overall retirement income program offered to new employees. Beginning in 2013, the traditional defined-benefit pension plan will be phased out. New employees will be automatically enrolled in a cash balance plan with higher contribution limits and higher employee matching. The prior company match was $0.60 on the dollar for unionized employees and $0.75 on the dollar for non-union employees, to a maximum of 6% of pay. The new company match is $0.75 on the dollar for all employees, to a maximum of 8% of pay.[1956] PG&E also expects some current employees will choose to maximize their RSP contributions due to a lower expected payout from the pension plan.

DRA analyzed the historical expenses for PG&E's RSP expense and reviewed the plan changes and actuarial reports. DRA does not oppose the base forecast for TY RSP program cost, but its lower estimate for employee population results in a DRA TY 2014 estimate of $77.981 million, an adjustment of $7.798 million.

8.4.5 Supplemental Executive Retirement Plan

PG&E forecasts $3.485 million for TY Supplemental Pension Plans PAYG expense.[1957] PG&E has two Supplemental Pension Plans – the Supplemental Executive Retirement Plan (SERP) and the Retirement Excess Benefit Plant – which provide benefits to certain highly-paid management employees who are subject to federal compensation and contribution limits in the retirement plans which are offered to all PG&E employees.[1958] PG&E offers two frozen plans – SERP and a plan for non-employee members of the Board of Directors – which continue to pay benefits to employees who retired when those plans were active. All of these plans provide benefits to covered employees on the same basis as the retirement plans offered to all other PG&E employees, but without any income and contribution limits. There is no pre-funded trust for Supplemental Pension Plans; PAYG costs include all benefits, actuarial fees, and administrative fees.[1959]

[1956] Ex. 35 (PG&E-8), pp. 7-17 through 7-19.

[1957] Ex. 37 (PG&E-8 workpapers), p. WP 7-1.

[1958] Ex. 35 (PG&E-8), p. 7-16.

[1959] Ex. 35 (PG&E-8), pp. 7-16 and 7-17.

DRA recommends that the Commission not allow any costs of the Supplemental Pension Plans to be included in TY expenses for rate recovery. DRA opposes having ratepayers bear the costs of benefits programs in excess of federal limits and which serve to further enhance benefits to already highly-compensated employees. PG&E has not shown that these are essential to attract executives. PG&E's executive benefits, which include the two plans offered to current executives, are 74% above market, according to the Total Compensation Study, clearly indicating that PG&E is already providing more than generous benefits to its executives.[1960] Ratepayers already contribute the appropriate pension plan contributions required under U.S. pension law for all employees, and ratepayers already fund 401(k) matching for all employees to the legal income and contribution limits. There is no basis for ratepayers to fund the costs associated with supplemental benefits above and beyond the legal limitations to which the company's rank and file employees are subjected. Ratepayers should not be required to bear the costs of exclusive executive benefits that exceed either what is authorized by the federal tax code and other pertinent laws and regulations, or what is offered as part of the company's normal employee coverage. Accordingly, DRA recommends that the Commission deny ratepayer funding for all Supplemental Pension Plans in TY 2014.

This approach has been used by Commissions in other jurisdictions. For example, in 2008, the Arizona Public Utilities Commission held that, if Southwest Gas Company wished to provide SERP, then shareholders, not ratepayers, should be responsible for these benefits.[1961] In 2009, the Connecticut Department of Utility Control held that, "ratepayers should not have to fund excessive benefits that are over and above the IRS code."[1962] In 2010, the Washington Utilities and Transportation Commission in a Puget Sound Energy rate case, recommended removal of supplemental retirement costs for executives who "already are highly compensated and entitled to the same levels of qualified retirement plan benefits as other employees, within the limits of what the IRS allows."[1963]

[1960] Ex. 35 (PG&E-8), p. 4-11.

[1961] *In the Matter of the Application of Southwest Gas Corporation* (2008) D.70665; 2008 Ariz PUC LEXIS 237 *30.

[1962] *Application of Connecticut Natural Gas Corporation* (2009) Docket No. 08-12-06; 2009 Conn. PUC LEXIS 117* 130.

[1963] *Washington Utilities and Transportation v Puget Sound Energy, Inc.* (2010), Dockets UE-090704 and

In Rebuttal, PG&E points to two recent GRC decisions by this Commission and their treatment of non-qualified pension costs for SCE and Sempra executives.[1964] In both decisions, the Commission found it reasonable to split the costs of those 50/50 between ratepayers and shareholders.[1965]

PG&E presents a different situation. Some of the same executives involved in the final steps of PG&E's budget process leading up to San Bruno are still involved in final decisions in PG&E's budget process now, and with the same ability to "re-allocate" and "re-prioritize" funds. To ask PG&E's ratepayers to pay any portion of exclusive benefits to these already highly compensated individuals is unjustified.

8.4.6 Service Awards

PG&E forecasted $1.300 million for TY Service Awards expense.[1966] DRA recommends zero funding for the TY Service Awards program.[1967]

PG&E says it shows appreciation for continuous service in the form of a gift to employees at each 5-year anniversary of their employment and at retirement.[1968] The value of these gifts ranges from about $50 for five years of service to over $600 for 55 years of service.[1969] PG&E's forecast includes an estimate of the number of employees eligible for gifts, and an assumption that only 82% of the eligible recipients will accept the gift.[1970] PG&E claims that the Service Award program is comparable to the 25-Year Service and Retirement Awards Program offered to employees of the State of California.[1971]

There are at least two key differences: number of awards for which each employee is eligible, and the cost of those awards. State employees are eligible for two awards, at 25 years of

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UG-090705 (consolidated), Order 11; 2010 Wash. UTC LEXIS 279* 64.

[1964] Ex. 62, p. 8-4.

[1965] D.12-11-051, pp. 475-477 and D.13-05-010, pp. 887-888.

[1966] Ex. 35 (PG&E-8), p. WP 6-1.

[1967] Ex. 82 (DRA-14), p. 19.

[1968] Ex. 35 (PG&E-8), p. 6-28.

[1969] Ex. 35 (PG&E-8), p. WP 6-25.

[1970] Ex. 35 (PG&E-8), p. WP 6-25.

[1971] Ex. 37 (PG&E-8 workpapers), p. WP 6-25.

service and at retirement, and the cost is limited to $90 each.[1972] PG&E employees are eligible for as many as 12 awards (every five years to 55 years, and at retirement) and at much higher costs.

DRA has historically opposed Service Awards as being a supererogatory expense, one that does not provide a clear and identifiable benefit to ratepayers or is not necessary to operate the utility business. If "the Company" wants to express its appreciation, it can do so at the Company's expense, rather than that of its ratepayers. DRA recommends zero funding for the TY Service Awards program. Should the Commission find 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.[1973]

8.4.7 Other

8.4.7.1 Tuition Credit

PG&E forecasts $3.861 million for TY Tuition Refund expense.[1974] DRA's TY 2014 estimate is $2.880 million, an adjustment of $981,000.[1975]

This program reimburses employees for the successful completion of job-related courses at accredited institutions. Approved courses can add effectiveness to an employee's current job or prepare an employee to assume new duties. The amount of potential annual reimbursement ranges from $2,500 to $8,000 depending on the type of employee and course of study. In 2011 PG&E outsourced administration for this program to a third party, edLink. PG&E claims that the contract fee is expected to be fully offset by savings in tuition with edLink's network of featured providers. Despite this, PG&E is forecasting projected increased costs due to expected higher enrollment under the preferred tuition rates.[1976] PG&E is also projecting increases related

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[1972] California Department of Human Resources, http://www.calhr.ca.gov/state-hr-professionals/Pages/25-year-service-and-retirement-awards.aspx

[1973] Ex. 82 (DRA-14), p. 20.

[1974] Ex. 37 (PG&E-8 workpapers), p. WP 7-1.

[1975] Ex. 82 (DRA-14), p. 27.

[1976] Ex. 35 (PG&E-8), pp. 7-19 and 7-20.

to program expansion to cover the Power Pathway Program in city colleges and to help retrain employees on long-term disability for a different job that is within their redefined capabilities.[1977]

PG&E provided no substantiation to support its claims that costs in this expense category would rise as projected. DRA, therefore, recommends using a three-year average of expense from 2009 through 2011 for a TY forecast of $2.880 million.[1978]

8.4.7.2 Employee Relocation

PG&E forecasts $6.322 million for TY Employee Relocation expense.[1979] DRA's TY 2014 estimate is $5.060 million, a total adjustment of $1.262 million.

PG&E's TY expense is based on a five-year average of historical expense, plus a projected increase in headcount.[1980] The expense in this category was at its second-highest point in 2007, it was at its highest point in 2008, and has dropped every year since then. DRA, therefore, recommends using a three-year average of expense from 2009 through 2011, or a forecast of $5.060 million.[1981]

8.5 Workers' Compensation

PG&E requests Test Year expenses for Workers' Compensation of $41.558 million. DRA does not oppose this request.[1982]

8.6 Workforce Management – Severance

PG&E forecasts $14.059 million for its Workforce Management – Severance Program costs in 2014. DRA recommends an adjustment of $3.243 million, for a DRA TY forecast of $10.816 million.[1983]

PG&E's forecast is based on an average of five years of historical expense. DRA analyzed the historical expenses (in base year dollars) and discovered that the years 2007 through

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[1977] Ex. 37 (PG&E-8 workpapers), p. WP 7-17.

[1978] Ex. 82 (DRA-14), p. 28.

[1979] Ex. 35 (PG&E-8), p. WP 7-1.

[1980] Ex. 37 (PG&E-8 workpapers), p. WP 7-19.

[1981] Ex. 82 (DRA-14), p. 28.

[1982] Ex. 82 (DRA-14), p. 29.

[1983] Ex. 82 (DRA-14), p. 33.

2009 have the highest expenses, with 2009 being double the expense of 2011, $18.1 million compared to $9.0 million. DRA recommends a two-year average of 2010 and 2011, as these years are the most recent expense history since that high-expense year, which is an anomaly compared to the years prior. This two-year average results in a DRA TY forecast of $10.816 million.

In Rebuttal, PG&E repeats its threats to lay off 3,000 employees if DRA's revenue requirement is adopted, and says that "… if the labor cost reductions proposed by DRA were adopted the Workforce management – Severance Program forecast for 2014 would be over $380 million."[1984] PG&E made a similar argument about adoption of DRA recommendations necessitating thousands of layoffs in in its TY 2011 GRC.[1985] In the end, the Commission adopted a settlement for the TY 2011 GRC for far less than what PG&E had asked for in its Application.[1986] And, as discussed above in Section 1.4 of this Opening Brief, PG&E's headcount increased in 2011.

9 ADMINISTRATIVE AND GENERAL EXPENSES

9.1 Introduction

The categories of Administrative and General (A&G) expenses cover general expenses not chargeable to a specific functional activity. A&G expenses are recorded in the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts 920 through 935. Many items comprise A&G expenses including Outside Services Employed, Injuries and Damages, Franchise Taxes, Regulatory Commission expenses, Miscellaneous General expenses, and Maintenance of General Plant. PG&E's A&G-related capital expenditures are for Information Technology (IT) initiatives proposed by specific A&G departments.

PG&E forecast its Test Year 2014 expenses using base-year costs. After the A&G organizations complete their individual forecasts, PG&E makes adjustments which are supposed to ensure that only those costs that should properly be borne by ratepayers are included in the GRC request. PG&E allocates a portion of the forecasted costs to capital, and then must remove

[1984] Ex. 62 (PG&E-23), p. 9-4.

[1985] Ex. 360 (PGE-18, TY 2011 Rebuttal Testimony of B. Fraser), p. 1-13.

[1986] Ex. 69 (DRA-1), p. 19.

costs associated with below-the-line activities and non-utility affiliates, and remove benefit costs associated with the labor of employees engaged in providing Non-Tariffed Products and Services.

PG&E's Direct Testimony addressed three distinct types of A&G expenses: Corporate Services Department costs, Companywide A&G expenses, and IT and Other Capital Projects for 2014. When it filed its Application, PG&E was seeking $243.9 million for Corporate Services Department costs, $153.7 million for Companywide A&G expenses, and $53.8 million in Capital and $12.9 million in expense for IT and Other Capital Projects.[1987]

DRA notes that many of the following recommendations are of dollar amounts that pale in comparison to the total revenue requirement PG&E requests. Nonetheless, DRA asks the Commission to consider the death- by- a- thousand- cuts approach PG&E used in its Application and continued in its Rebuttal. Obviously, PG&E is aware that these small amounts add up; the Commission should be too. The areas where DRA disputes PG&E's A&G forecasts are discussed below.

9.2 Finance Organization Costs

The Finance Organization is responsible for such functions as raising capital, communicating with investors, providing financial forecasts, working with the other organizations within PG&E to plan and manage budgets, filing financial statements with the Securities and Exchange Commission (SEC) and other regulatory bodies, making all necessary tax filings with federal and state authorities, and managing payment services for employees and vendors.

The Finance Organization consists of five sub-departments: the Senior Vice President and Chief Financial Officer; Business Finance, Controller, Investor Relations and Treasury. DRA does not dispute PG&E's forecasts for Senior Vice President and Chief Financial Officer; Business Finance, Investor Relations or Treasury. DRA does, however, dispute PG&E's forecast for Controller Department costs.

[1987] Ex. 38 (PG&E-9), pp. 1-1—1-2.

9.2.1 Controller

The Controller's Department is primarily responsible for financial accounting and reporting, enterprise forecasting and monitoring, payment services to employees and vendors, and tax planning and compliance. The Controller's Department comprises the Vice President's office and five sections: Capital Accounting, Corporate Accounting, Financial Forecasting and Analysis, Payment Services, and Tax.

In its Application, PG&E's forecast for the Controller's Department 2014 costs is 30.946 million, or 68.6% of the total Finance Organization request. PG&E's TY 2014 forecast is $3.5 million, or 12.6%, higher than the 2011 recorded adjusted amount of $27.488 million. The increase is due primarily to wage escalation and a slightly higher escalation factor for external audit fees. PG&E says that adjustments to recorded 2007 through 2011 are for costs related to reorganization and to the San Bruno disaster.[1988]

PG&E's TY 2014 forecast includes $95,627 for Outside Services – Corporation. DRA recommends this amount be removed from any forecast the Commission adopts for PG&E. Although, given the magnitude of PG&E's overall proposed rate hike, $96,627 is *de minimis*, ratepayers should not have to pay for costs PG&E did not justify in its Application. In Rebuttal[1989], PG&E points to workpapers submitted in March 2013, four months after filing its Direct testimony, for the supposed justification for this increase. DRA continues to recommend that this amount be specifically removed from ratepayer funding.

PG&E's TY forecast for the Controller's Department also includes $.027 million for External Audit fees. DRA recommends that this forecast be reduced to $4.077 million.

PG&E's original forecast was ostensibly based on an expectation that International Financial Standards would be implemented. They have not been.[1990] With nothing more than PG&E's unsupported assumption that the new standards will be implemented in 2014, there is no factual basis to charge ratepayers with this increase.

[1988] Ex. 84 (DRA-16), p. 17 citing HRG Ex. 38 (Ex. PG&E-9, workpapers) p. WP 2-52.

[1989] Ex. 63 (PG&E-24), p. 1-4.

[1990] Ex. 63 (PG&E-24), p. 1-4.

9.2.2 Finance Organization – Information Technology Projects

PG&E says that its Finance Organization plans five Information Technology (IT) projects to "…ensure compliance with new accounting regulations, maintain core financial systems, and improve the usability and enhance the capability of PG&E's core financial systems."[1991] PG&E is forecasting $2.6 million for expense in 2014, and $7.4 million for capital expenditures in 2012 and $3.4 million in 2013. For 2014 capital expenditures, PG&E forecasts $8.226 million, $7.9 million in 2015, and $6.8 million in 2016. PG&E's IT expense costs are forecasted in MWC JV (Maintain Application and Infrastructure); IT capital costs are forecasted in MWCV 2F (Build Applications and Infrastructure).[1992]

DRA recommends adjustments to both the IT expense and capital forecasts. Of the $8.226 million PG&E forecasts for Finance Organization IT capital projects, $1.951 million is for "IT Project Accounting Convergence."[1993] In Rebuttal, PG&E "… agrees that there is uncertainty related to the timing of ultimate adoption of IFRS in the United States." PG&E, therefore, "agrees to remove these costs from its forecast." [1994]

For the remaining IT capital projects, DRA recommends that an additional $878,500 be removed from the Finance Organization's test year 2014 forecast to reflect DRA's recommendation regarding PG&E's IT estimating tool.[1995] Given DRA's concerns regarding PG&E's IT estimating tool, DRA similarly recommends $358,400 be removed from the Finance Organization's IT expense forecast for 2014 as well.[1996]

9.3 Risk and Audit Department Costs and Insurance Expenses

PG&E forecasts TY 2014 costs for its Risk and Audit Department of $19.2 million, a 21% percent increase over its 2011 adjusted recorded costs of $15.9 million. The increase is due

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[1991] Ex. 38 (PG&E-9), p. 2-27.

[1992] Ex. 84 (DRA-16), p. 25.

[1993] Ex. 84 (DRA-16), p. 25.

[1994] Ex. 63 (PG&E-24), p. 1-7.

[1995] Ex. 86 (DRA-18), Shared Services & Information Technology Costs).

[1996] Ex 84 (DRA-16), p. 25.

to increased staffing of 13.3 Full-Time Equivalents (FTEs) and represents $1.2 million in wage escalation.[1997] DRA recommends $18.090 million for the test year.[1998]

PG&E's Risk and Audit Department consists of five sub-departments: Vice President's Immediate Office (Chief Risk Officer), Internal Audit, Market and Credit Risk Management, Corporate Security, and Enterprise Risk Management and Insurance Department. DRA disputes PG&E's forecasts for three of those sub-departments: Vice President's Immediate Office, Corporate Security and Enterprise Risk Management and Insurance.

For IT expenses for its Risk and Audit Department, PG&E forecasts $4.045 million in 2014. DRA's recommendation is $3.479 million.[1999]

For IT capital expenditures, PG&E forecasts $2.550 million in 2012, $700,000 for capital in 2013, $33.770 million[2000] in 2014, $8.070 million in 2015, and $6.220 million in 2016. DRA's recommendation for IT capital expenditures for PG&E's Risk and Audit Department for TY 2014 is $12.170 million.[2001]

The differences between PG&E's forecasts and DRA's recommendations for Risk and Audit Department Costs and Insurance Expenses are discussed below.

9.3.1 Vice President Chief Risk Officer's Immediate Office

PG&E and DRA disagree on the appropriate forecast for PG&E's Vice President Chief Risk Officer TY 2014 Outside Services – Corporation costs.[2002] PG&E forecasts $226,928 for TY 2014. PG&E's 2011 recorded costs were zero, which is what DRA recommends for this GRC period.

Again, although this dollar amount appears insignificant in comparison to PG&E's overall revenue requirement request, DRA opposes PG&E's attempt to burden ratepayers with the consequences of PG&E Corporation's multiple internal reorganizations. PG&E's

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[1997] Ex. 38 (PG&E-9), p. 3-1.

[1998] Ex. 84 (DRA-16), p. 28, Table 16-15.

[1999] Ex.84 (DRA-16), p. 29, Table 16-16.

[2000] Ex. 84 (DRA-16), p. 28, footnote 43 stating that "[t]hese costs include the capital forecast for the IT portion of the alternate [Emergency Operations Center]."

[2001] Ex. 84 (DRA-16), p. 30, Table 16-17.

[2002] These costs are recorded in FERC Account 923.

adjustments to FERC Account 923 - Corp for 2007 through 2011 relate to the reorganization from PG&E Corporation to PG&E the Utility. Actual recorded costs for the years 2007 through 2011 are embedded in PG&E's adjusted recorded costs for Accounts 920, 921, and 923-Utility. PG&E's testimony does not provide any compelling supporting documentation as to why it is forecasting costs for Account 923-Corp for the test year 2014. Therefore, DRA recommends that $226,928 be removed from test year 2014 forecast.

9.3.2 Enterprise Risk Management and Insurance Department (Administrative Costs)

For its Enterprise Risk Management and Insurance Department, PG&E forecasts $1.926 million, or 47% more its 2011 recorded adjusted amount of $1.311 million.[2003] DRA recommends that $573,000 in labor costs be removed from the TY 2014 forecast.

In Direct Testimony, PG&E said that it wants ratepayers to fund the expansion of PG&E's Enterprise Risk Management team by the addition of three staff persons in test year 2014. PG&E says this expanded role is to manage risk at PG&E and manage the new Operational Risk Management Program (ORMP). PG&E's workpapers indicate that this project is not mandated.[2004]

In Rebuttal, PG&E uses the San Bruno accident, the criticisms of the Independent Review Panel, and the Report of the Liberty Consulting Group[2005] to argue for ratepayer funding of PG&E's newly discovered interest in risk assessment as it relates to public safety.

PG&E's ratepayers have been paying "Risk Management" costs for years. The fact that PG&E chose to use that funding to protect the financial interests of its shareholders rather than the safety of the public does not justify saddling ratepayers with additional costs now for protection PG&E should have been providing all along. DRA continues to recommend zero additional ratepayer funding for this item.

9.3.3 Corporate Security

PG&E's Corporate Security Department forecasts $2,903,377 for the Test Year. This is an increase of 45.16% from 2011 adjusted recorded costs of $2,183,726.[2006] Part of the

[2003] Ex. 84 (DRA-16), p. 35.

[2004] Ex. 39 (PG&E-9 workpapers), p. WP 3-95.

[2005] Ex. 63 (PG&E-24), p. 2-4.

requested increase is to add 6.3 FTEs from 2011 to 2014. DRA has reviewed PG&E's testimony and accompanying workpapers and does not oppose this portion of PG&E's test year 2014 labor forecast.[2007]

PG&E also says it wants to add one director in 2013 with security technology expertise to support the use of technology and data analytics in security operations.[2008] According to PG&E, "The new director will replace the current senior director of Corporate Security who will be retiring. PG&E plans to hire the director in 2013 in advance of that retirement for succession planning purposes."[2009] The labor costs associated with the current senior director of Corporate Security are embedded in 2011 adjusted recorded costs. Corporate Security's proposed increase in 2013 labor costs of $264,000 includes the anticipated new director. Therefore, the labor forecast for test year 2014 includes both the retiring director and his/her replacement. Ratepayers should not be asked to fund labor costs for the retiring director and his/her replacement in the test year 2014. DRA recommends that $123,000[2010] be removed from test year 2014 labor costs.

In Rebuttal, PG&E says that "[b]ecause of the critical nature and importance of this position, it is appropriate for the current director to remain to train his replacement based on his years of experience in the role…"[2011] This is still no reason for ratepayers to fund two salaries for one job.

9.3.4 Capital Project – Alternate Emergency Operations Center

According to PG&E, the locations of its primary facilities at 77 Beale Street in San Francisco and its alternate Company Headquarters and Emergency Operations Center (EOC) in the San Ramon Valley Conference Center are located in areas where earthquakes could render

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[2006] Ex. 39 (PG&E-9, workpapers), p. WP 3-67.

[2007] Ex. 84 (DRA-16), p. 37.

[2008] Ex. 38 (PG&E-9), p. 3-8.

[2009] Ex. 362 and 363.

[2010] Ex. 39 (PG&E-9, workpapers), p. WP 3-75 line 5.

[2011] Ex. 63, p. 2-5.

both facilities partially or totally unusable for a period of time.[2012] The last major earthquake in the San Francisco Bay Area was the Loma Prieta earthquake in 1989.

PG&E says that it plans to establish an alternate EOC at a location outside the greater Bay Area.[2013] The alternate EOC will provide immediate occupancy to critical business activities in the event facilities in the Bay Area are impacted.[2014] For this project, PG&E forecasts $19.9 million in capital in 2014, of that, g $13 million is for the building portion for the project, and $6.9 million is for the IT portion. The capital costs are forecasted in MWC 23 (Implement Real Estate Strategy) and MWC 2F (Build IT Applications and Infrastructure) that includes the costs for the new buildings and the purchase and installation of furniture, office equipment, and IT Infrastructure.

As part of the EOC project, PG&E is forecasting $250,000 in expense to fund a feasibility study[2015] for an alternate PG&E headquarters (ACHQ). The consultant is supposed to identify the essential personnel to be located at an alternate headquarters facility in the event PG&E's General Office buildings are not available for extended period. Once the study is complete in 2014, PG&E will be able to determine the size of the alternate headquarters and develop a proposal to establish the facility. PG&E is not forecasting construction costs for the ACHQ in this general rate case.[2016] This feasibility study is a one-time expense and, therefore, should be normalized for the test year. DRA recommends that $166,667 (two-thirds of the $250,000 expense) be removed from Account 923 Outside Services-Utility test year 2014 forecast.

No specific site has been identified for this Alternate EOC and PG&E has not purchased land for it.[2017] The Commission should not make ratepayers fund this capital project at this time.

PG&E says it is not requesting funding for its Alternate Company Headquarters until after it has completed a feasibility study. Since neither the alternate EOC nor the Alternate

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[2012] Ex. 38 (PG&E), p. 3-10.

[2013] PG&E's plan is to have a location outside the nine Bay Area counties.

[2014] Ex. 38 (PG&E-9), p. 3-10.

[2015] Ex. 38 (PG&E-9), p. 3-10.

[2016] Ex. 84 (DRA-16), p.39, footnote 73 citing response to DRA-PG&E-177-DFB, Q. 4.

[2017] Ex. 84 (DRA-16), p. 39 footnote 74 citing response to DRA-PG&E-010-DFB, Q. 17.

Company Headquarters has a specific location, it is not reasonable to ask ratepayers to fund $19.9 million in construction costs at this time.

In Rebuttal, PG&E says that "…the lack of a specific site does not impact the forecast for this project except for the amount of fiber optic cable."[2018] This in unrealistic, to say the least. Whatever site is eventually selected, construction will undoubtedly be subject to permit requirements. Permitting requirements and construction costs can vary dramatically from county to county. It is unreasonable and premature to charge ratepayers for a project that is still entirely speculative.

9.3.5 Property and Liability Insurance Expenses

PG&E is forecasting Property and Liability Insurance of $105.242 million, a 105% increase over PG&E's 2011 recorded adjusted amount of $51.324 million. DRA recommends ratepayer funding of no more than $50.139 million in the test year.[2019]

According to PG&E, the increase it forecasts for insurance expenses is due to a variety of factors including "continued concerns about wildfire risk in California, the large nuclear property claim at Crystal River, concerns regarding the age of infrastructures following the San Bruno accident, and the major catastrophic losses that have occurred worldwide, such as the earthquake and tsunami in Japan, floods in Thailand, the British Petroleum oil spill, earthquake in New Zealand and severe weather outbreaks in the United States."[2020]

9.3.5.1 Non-Nuclear Property Insurance

PG&E's maintains non-nuclear property insurance and nuclear property insurance. PG&E's Non-Nuclear Property Insurance provides coverage for the costs of repair and/or replacement of damage property from perils as storms, earthquakes and fires at PG&E's non-nuclear facilities.[2021] PG&E is forecasting $21.1 million in expenses for 2014, which is 41.3% higher than the 2011 recorded adjusted amount of $15.235 million. According to PG&E, this increase is driven by two factors: 1) overall price increases in the marketplace due to the large

[2018] Ex. 63 (PG&E-24), p. 2-7.

[2019] Ex. 84 (DRA-16), p. 28, Table 16-15.

[2020] Ex. 38 (PG&E-9), p. 3-11.

[2021] Ex. 38 (PG&E-9), p. 3-12.

number of significant property claims including the major flood and earthquake damage that occurred globally in 2011; and 2) PG&E's efforts to upgrade and replace its asset base.[2022]

PG&E forecasted a 17% ($17.852 million) increase in property insurance for 2012, a 12% ($19.950 million) increase in 2013, and an 8% ($21.521 million) increase in 2014. PG&E's 2012 recorded non-nuclear insurance was $16.757 million.[2023] This is a 10% increase over the 2011 recorded cost of $15.235 million. The recorded 2012 non-nuclear property insurance is 7% lower than PG&E's 2012 forecast of $17.852 million, and 28% lower than test year 2014 forecast of $21.521 million.

DRA recommends the Commission to use PG&E's recorded 2012 property insurance as the basis for forecasting the test year 2014. DRA forecasts a 6% increase (to $17.762 million) in 2013, and a 4% increase (to $18.473 million) in test year 2014. DRA's recommendations reduce PG&E's request by $3.048 million.[2024]

In Rebuttal, PG&E says that "…2012 data is inappropriate to use as the starting point to determine the 2014 forecast," and that "DRA has not typically made similar recommendations in other areas where using 2012 data would increase the forecast."[2025] First of all, there is nothing "inappropriate" in using 2012 data. As the Commission has found in other GRCs:

> Several different methods can be used to calculate test year estimates of expenses, e.g., linear trending, averaging (e.g. five year average (5YA) recorded expenses), last recorded year (LRY), and budget based estimates.[2026]

In fact, in this GRC, PG&E sponsored testimony criticizing DRA for "…overlook[ing] more recent spending trends in 2012 and 2013."[2027] As to the statement that "DRA has not typically made similar recommendations in other areas ... "this is both unsubstantiated, and irrelevant. DRA attempts to assess the reasonableness of utility forecasts based on the specifics of the project. As the Commission has noted:

[2022] Ex. 38 (PG&E-9), p. 2-12.

[2023] Ex. 84 (DRA-16), p. 43, footnote 80, citing response to DRA-PG&E-110-DFB, Question 1.

[2024] Ex. 84 (DRA-16), p. 43.

[2025] Ex. 63 (PG&E-24), p. 2-10.

[2026] D.12-11-051, mimeo., p. 13.

[2027] Ex. 58 (PG&E-21), p. 3-1, lines 25-26.

> …there are a number of acceptable methodologies for forecasting test year costs….Depending on circumstances, one method may be more appropriate than others. Under other circumstances, two or more methods may be equally appropriate. In general, the parties' testimony should explain (1) why its methodology is appropriate, (2) why it is better than methodologies proposed by other parties, and (3) why the results are reasonable.[2028]

DRA's recommendations meet all of those criteria. DRA continues to recommend the Commission adopt a forecast of $18.473 million in test year 2014 expenses for non-nuclear property insurance.

9.3.5.2 Excess Liability Insurance

Excess Liability Insurance provides coverage for claims from third parties alleging personal injury or property damage.[2029] PG&E is forecasting $71.96 million in expenses for 2014, which is a 143% increase from the 2011 adjusted recorded costs of $29.618 million. According to PG&E, the increase is based on insurance industry concerns about the age of infrastructure in the U.S., in general, and in California, in particular.[2030] Significant losses for the insurance industry affect excess liability premiums. This includes costs of the San Bruno accident as well as other losses worldwide.

PG&E's excess liability insurance increased 53% in 2010 and again in 2011. PG&E forecasted a 45.5% increase in 2012 ($46.593 million), a 46% increase in 2013 ($67.932 million), and a 10% increase in 2014 ($74.451 million). PG&E's 2012 recorded excess liability insurance was $33.579 million.[2031] This is an 18.8% increase over the 2011 recorded cost of $32.003 million. The recorded 2012 excess liability insurance is 28% lower than PG&E's 2012 forecast of $46.593 million.

PG&E's excess liability insurance costs increased significantly in 2010 and 2011 at levels well above prior years. The increase in 2012 moderated significantly compared to the two prior years. DRA concludes that the last recorded expenses from 2012, equal to $33.579 million,

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[2028] D.06-05-016, mimeo, pp. 10-11.

[2029] Ex. 38 (PG&E-9), p. 3-14.

[2030] Ex. 38 (PG&E-9), p. 3-14.

[2031] Ex. 84 (DRA-16), p. 44.

should be the basis for forecasting the test year 2014 expense. With that, DRA forecasts a 4% increase in 2013, to $34.922 million, and a 4% increase in test year 2014, to $36.319 million. The 4% percent increase is slightly higher than the wage escalation rate that PG&E uses in this GRC. DRA removed $11.1 million on the DRA Financial Examiner's recommendation.[2032] DRA forecasts test year 2014 excess liability insurance at $25.219 million, reducing PG&E's test year 2014 excess liability insurance expenses by $49.232 million.

9.3.5.3 Directors and Officers Liability

The Directors and Officers (D&O) liability program provides coverage for claims alleging wrongful acts such as breach of fiduciary duty by PG&E's directors or officers. PG&E is forecasting $3.387 million in D&O expenses for 2014, which is 31.8% higher than the 2011 recorded adjusted amount of $2.569 million.

PG&E's recorded D&O insurance expense for the period 2007 through 2011 was $4.325 million, $3.335 million, $3.252 million, $2.911 million, and $2.569 million. The D&O insurance cost has decreased approximately 41% during that five year time frame. The recorded D&O Insurance expense is showing a downward trend while PG&E is forecasting a 31.84% (or $818,000) increase over recorded 2011 expense. The 2012 last recorded year costs were $2.511 million,[2033] a 2% decrease from the 2011 recorded costs of $2.569 million.

Given the downward trend in these insurance costs, it is not reasonable to allow PG&E to charge ratepayers a 32% increase. DRA recommends that the 2012 recorded be used as the basis for forecasting PG&E's 2014 D&O insurance expenses.

In addition to overstating its forecast for Directors and Officers Liability insurance, PG&E asks the Commission to include 100% of these costs in rates. This is contrary to the Commission policy for Directors and Officers insurance in place since at least 1996.

In its 1996 decision resolving the GRC application of Southern California Edison Company (SCE),[2034] the Commission found it appropriate to allocate 50% of the Directors Officers insurance costs to shareholders to reflect the benefits they received from this insurance. In its decision resolving PG&E's TY 1999 GRC, the Commission allowed PG&E to recover half

[2032] Ex. 84 (DRA-16), p. 45 citing HRG Ex. 91 (DRA-23). See also, Section 2.3 of this Brief, above.

[2033] Ex. 84 (DRA-16), p. 45, footnote 86 citing response to DRA-PG&E-110-DFB, Q1Supp02.

[2034] Re Southern California Edison Company (1996) 64 CPUC2nd 241, 319; d.96-01-011.

of its Directors and Officers insurance costs from ratepayers, while the other half was to be recovered from shareholders.[2035] The Commission's reasoning was that the Directors and Officers insurance benefited both the utility's shareholders and ratepayers. In its 2004 decision resolving the GRC of Southwest Gas Corporation, the Commission stated:

> However, D&O insurance protects directors and officers from activities that benefit both shareholders and customers. Therefore, we will adopt an amount for D&O insurance that allocates the costs of D&O insurance equally between shareholders and customers.[2036]

The Decision from San Diego Gas & Electric Company/Southern California Gas Company's 2012 GRC states:

> On the issue of whether the directors and officers liability should be borne mostly by SDG&E and SoCalGas, or if 50% of the costs should be borne by Sempra's shareholders, we agree with DRA and FEA. Although this type of insurance is used to attract and retain executives, the Applicants acknowledge that such insurance protects Sempra's Board members and officers from catastrophic losses, which is a benefit that accrues to shareholders, rather than ratepayers. For that reason, of the $3.515 million allocated to the two utilities, SDG&E and SoCalGas should each be allocated 50% of this amount, i.e., $879,000 each.[2037]

The Commission's policy regarding Directors & Officers insurance is for ratepayers and shareholders to equally share in the costs. PG&E has not provided any compelling arguments that would warrant the Commission changing its policy. Therefore, DRA that the Commission require ratepayers to pay no more than one-half of the $2.511 million, or $1.256 million, for PG&E's test year 2014 Directors and Officers insurance expense.

9.3.5.4 PG&E Corporation Property and Liability Insurance

PG&E Corporation is insured under several insurance programs that provide the same type of coverage for property and liability risks as the Utility (e.g., protection for claims from third parties alleging personal injury or property damage, and coverage for the cost of repairing

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[2035] Application of Pacific Gas and Electric Company (TY 1999 GRC) (2000) D. 00-02-046, mimeo p. 305.

[2036] D.04-03-034, mimeo., pp. 32 and 33.

[2037] D.13-05-010, mimeo., p. 851; 2013 Cal. PUC LEXIS 283.

or replacing damage from an earthquake).[2038] PG&E is requesting that ratepayers fund $692,000 in 2014 for this expense.

PG&E says that PG&E Corporation performs the majority of its work for PG&E – Utility. While this may or may not be true, ratepayers should not be asked to fund additional property and liability insurance for PG&E Corporation. Ratepayers already fund PG&E – Utility's property and liability insurance, which includes property, Directors & Officers, and excess liability insurance. 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. Therefore, DRA recommends a forecast of $0.

9.3.6 Risk and Audit Department – Information Technology Projects

The Market and Credit Risk Management section of the Risk and Audit Department is forecasting the need for four IT projects: (1) Energy Trading and Risk Management (ETRM) Implementation; (2) Risk Engine Consolidation; (3) Position Reporting Centralization; and (4) Data Consolidation.[2039] PG&E is forecasting $1.5 million in expense in 2014, and $2.6 million for capital expenditures in 2012, $11.0 million in 2014, $5.0 million in 2015, and $4.0 million in 2016.

In addition to the IT work forecasted with the Alternate EOC in 2014, the Corporate Security Department is planning four IT projects to make necessary enhancements to PG&E's physical security and life safety programs. PG&E is forecasting $2.0 million expense for 2014, and $2.9 million for capital expenditures in 2014, $3.1 million in 2015, and $2.2 million in 2016.[2040]

9.3.6.1 IT Expenses

The Risk and Audit Department's total IT expense forecast for test year 2014 is $4.045 million and is reflected in MWC JV Maintain IT Applications and Infrastructure. PG&E developed the costs forecast for each IT project using PG&E's application development concept

[2038] Ex. 38 (PG&E-9), p. 3-16.

[2039] Ex. 38 (PG&E-9), p. 3-17.

[2040] Ex. 38 (PG&E-9), p. 3-19.

estimating tool.[2041] DRA addresses the problems with relying on estimates produced by this tool above in Section 7 of this Opening Brief. DRA, therefore recommends that $556,000 be removed from test year 2014 Risk and Audit Departments' IT expense.[2042]

9.3.6.2 IT Capital Expenditures

The Risk and Audit Department's total IT capital forecast for test year 2014 is $33.770 million and is reflected in MWC 23 Implement Real Estate Strategy ($13 million) and MWC 2F Build IT Applications & Infrastructure ($20.77 million).[2043] PG&E developed the cost forecast for each IT project using its application development concept estimating tool.

The MWC 23, Implement Real Estate Strategy ($13 million) and $6.9 million of the $33.77 million in MWC 2F, Build IT Applications & Infrastructure relates to the AEOC. DRA's disagreement with PG&E's capital forecast for the AEOC is discussed above. DRA's disagreement with reliance on the estimating tool is discussed above in Section 7 of this Opening Brief.

DRA's recommends that $21.842 million be removed from test year 2014 Risk and Audit Department's IT capital expenditures, and that the Commission adopt a forecast of no more than $11.928 million for test year 2014.

9.4 Human Resources Department and HR Technology Costs

PG&E is requesting that the Commission adopt PG&E's 2014 forecast of $62.2 million in expenses for its Human Resources (HR) Department costs.[2044] PG&E also requests $3.8 million for IT expenses in 2014, and $7.9 million for capital expenditures over the period from 2012 through 2016.[2045] PG&E's forecast for its Human Resources Department costs is $12.9 million, or 26%, higher than the 2011 recorded adjusted amount of $49.3 million.[2046]

The areas where DRA disagrees with PG&E's forecasts are discussed below.

[2041] Ex. 30 (PG&E-7), Chapter 8.

[2042] Ex. 84 (DRA-16), p. 48.

[2043] Ex. 38 (PG&E-9), p. 3-23, Table 3-5.

[2044] Ex. 38 (PG&E-9), p. 4-1.

[2045] Ex. 38 (PG&E-9), p. 4-1.

[2046] Ex. 38 (PG&E-9), p. 4-1.

9.4.1 Vice President Human Resources

The Vice President Human Resources section includes the functional areas of Human Resources Delivery, Labor Relations, Compensation and the PG&E Academy. Of these, DRA disputes PG&E's forecasts for Human Resources Delivery and the PG&E Academy.

9.4.1.1 HR Delivery Costs (PCCs 10382, 12911, 13627, 13629, 10322, 10379, 10482, 10387, 10377, 10378, 10380, 10388, 10381, 10478, 12733, 20054, 10383, 10386, 12991, 13629, 14104, 14523, 14828, 14896)

PG&E is forecasting $7.7 million in its Test Year 2014 GRC for Human Resources Delivery Costs.[2047] DRA recommends $6.04 million for PG&E's HR Delivery Department.[2048]

PG&E's HR Delivery costs are broken down into forecasts for three teams: (1) HR Delivery Consulting, (2) HR Service Center, and (3) Equal Employment Opportunity and Affirmative Action.[2049]

HR Delivery Consulting provides "front line" HR support to senior service leaders.[2050] PG&E's HR Delivery Consulting team consists of the HR Directors, Managers and Consultants who work with PG&E's LOB senior leaders to implement new HR Programs and existing ones. In addition, PG&E says that "this team is responsible for handling confidential employee issues, enlisting subject matter experts and assuming the role of HR contact for leaders human resources needs."[2051] HR Delivery Consulting had 32 employees in 2011.[2052]

HR Service Center provides phone and email support to employees, supervisors and managers, as well as processes for employee and retiree-related transactions. It fields calls and emails from individual employees, supervisors, retirees and in some cases higher level leaders when they need assistance or have questions about HR programs, policies or transactions. In

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[2047] Ex. 39 (PG&E-9, workpapers), p. WP .4-2.

[2048] Ex. 85, p. 17.

[2049] Ex. 38, (PG&E-9), p.4-20.

[2050] Ex.38 (PG&E-9), p.4-20.

[2051] Ex. 38 (PG&E-9), p.4-20.

[2052] Ex. 38 (PG&E-9), p.4-20.

2011, HR Service Center answered over 71,000 employee and retiree calls and processed well over 30,000 individual transactions.[2053] HR Service Center had 13 employees in 2011.[2054]

The Equal Employment Opportunity (EEO) and Affirmative Action (AA) functions "conduc[t]s investigations related to EEO and AA complaints and provide[s] training related to EEO and AA compliance obligations." PG&E says that "[t]he EEO investigation team thoroughly investigates all discrimination or harassment related complaints to determine whether they are alleging an instance of discrimination, harassment, a violation of PG&E policy, or where an employee is concerned about retaliation."[2055] The EEO "team" consisted of 6 employees in 2011.[2056]

PG&E says that it "… plans to implement process and technology improvements that will reduce the number of transactions that HR employees process centrally, freeing up resources to work with field supervisors, managers, and employees."[2057] In 2012, PG&E added 7 new employees to the HR Delivery Department. At year-end (YE) 2012, the HR Delivery Department consisted of 58 employees, and PG&E is forecasting 66 employees by 2014.[2058]

PG&E has not provided adequate support or justification for an additional 8 new employees in 2014. In its Direct testimony and workpapers, PG&E provided no information to show that the 7 new employees added in 2012 are insufficient to meet the current workload.

In Rebuttal, PG&E says that "PG&E does not currently have a sufficient number of HR employees in the field to provide support to supervisors and managers."[2059] This is yet another generalization; PG&E still has not offered any factual basis for its claim.

If any managers or supervisors at PG&E are not receiving HR assistance to comply with "federal, California and local employment laws,"[2060] while PG&E is devoting millions of dollars to public relations campaigns, and Short Term Incentive Plan payouts, then the problem lies not

[2053] Ex. 38 (PG&E-9), p.4-21.

[2054] Ex. 38 (PG&E-9), p.4-20.

[2055] Ex. 38 (PG&E-9), p.4-22.

[2056] Ex. 38 (PG&E-9), p.4-20.

[2057] Ex. 38 (PG&E-9), p.4-23.

[2058] Ex. 38 (PG&E-9), p.4-23.

[2059] Ex. 63, p. 3-4.

[2060] See Ex. 63, p. 3-4, lines 17-18.

in funding levels, but in PG&E's spending decisions. Moreover, if PG&E's 2014 Human Resources Delivery forecasts is based on the assumption that PG&E's request for thousands of new employees in the coming GRC period is granted, DRA disputes that assumption as well.

Due to lack of support, DRA recommends that the Commission use the YE 2012 recorded employee head count and all associated costs in FERC Accounts 920 and 921 escalated by roughly 3% per year for 2 years. This $6.04 million is most reflective of PG&E's current spending.[2061]

9.4.1.2 PG&E Academy Department Costs (PCCs 12867, 13735, 14026, 14027, 12912, 13705, 10393, 10391, 10375, 11681, 12484, 12868, 12869, 12870, 12871, 14918, 14453, 14906, 10391, 12885)

PG&E forecasts $10.3 million in its Test Year GRC for PG&E Academy Department Costs.[2062] DRA forecasts $7.71 million.[2063]

PG&E Academy is PG&E's centralized internal training organization.[2064] According to PG&E, the mission of PG&E Academy is to increase employee safety and productivity by designing, delivering and measuring top quality, in-classroom and online learning.[2065] In 2011, PG&E Academy delivered 6,800 training sessions covering over 200 different topics through instructors or on-the-job training to employees in areas such as Electric Operations, Equipment, Gas Operations and Safety and Compliance.[2066] The instructor-led and on-the-job training sessions represented over 40,000 student days. In addition, 58 separate web-based technical training classes were offered to employees and contractors.[2067] Twelve of these online courses were developed in 2011.[2068] PG&E Academy consists of six teams: Gas Training, Electric

[2061] Ex. 84 (DRA-17), p. 10.

[2062] Ex. 39 (PG&E-9), WP.4-2.

[2063] Ex. 85 (DRA-17), p. 12.

[2064] Ex. 38 (PG&E-9), p.4-26.

[2065] Ex. 38 (PG&E-9), p.4-26.

[2066] Ex. 38 (PG&E-9), p.4-26.

[2067] Ex. 38 (PG&E-9), p.4-26.

[2068] Ex. 38 (PG&E-9), p.4-26.

Training, Equipment and Compliance Training, Enterprise Systems Training and Change Management, Professional Development, and Academy Operations.[2069]

PG&E requests 10 new employees in its 2014 forecast.[2070] In 2011 PG&E recorded 34 FTEs which it then increased by 12.5 FTEs to 46.5 FTEs by YE 2012.[2071] This 36.8% increase is already significant.[2072] PG&E wants to increase the employee count by another 21.5% from 2012 to 2014.[2073] That is an overall increase of 66.2% over a 3 year period, from 2011 to 2014. PG&E has not justified imposing this burden on its ratepayers.

The 2012 recorded expense level is most indicative of what PG&E is currently spending. For 2014, DRA recommends ratepayer funding for the PG&E employee headcount at YE 2012. PG&E has not shown that the 10 new FTEs requested for 2014 are needed given that PG&E already increased staffing by 12.5 FTE's in 2012. Nor has PG&E shown that additional staff is needed for the new Webcast Studio and Technical Training maintenance work. DRA recommends using 2012 recorded expense of $3.48 million, escalated by roughly 3% per year for Account 923. Neither PG&E's testimony nor its workpapers[2074] provide enough support to add 10 new employees at ratepayer expense in 2014.

PG&E also provided little support for the Technical Training maintenance work it says is needed in Account 923. When DRA asked for detail on the increased costs for curriculum development work and Electric Qualification Program support, PG&E responded by stating that "923 Outside Services includes additional contract support to provide the oversight and curriculum direction required to develop new courses for gas and electric operations. This oversight also includes the development of the appropriate assessments for each course. **When appropriate** (emphasis added) these assessments are used to determine if an employee or contractor has successfully gained the required knowledge and skill covered in the particular

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[2069] Ex. 38 (PG&E-9), p.4-26.

[2070] Ex. 38 (PG&E-9), WP.4-69.

[2071] Ex. 85 (DRA-17), p. 12, footnote 47.

[2072] Ex. 85 (DRA-17) p. 12, line 10.

[2073] Ex. 85, p. 12, line 11, footnote 48.

[2074] Ex. 38, (PG&E-9), pp. 4-26 – 4-32; HRG Ex. 39 (PG&E-9, workpapers) pp. WP 4-189 – 4-191.

class and is qualified to complete the work back on the job."[2075] DRA interprets "when appropriate" as meaning that assessments are not always necessary. An $854,656 expense to ratepayers is excessive and burdensome given that it is only sometimes used. Thus, for 2014, DRA recommends the 2012 recorded expense of $3.32 million escalated over 2 years.[2076]

9.4.2 Talent Management

PG&E requests $22.0 million in its Test Year 2014 GRC for the Talent Management.[2077] The forecast is an increase of $4.6 million from 2011 recorded costs.[2078]DRA is forecasting $19.38 million for PG&E's Talent Management Group for the Test Year.[2079]

PG&E says its Talent Management and Inclusion function provides an integrated, end-to-end view of workforce development, employee recruitment, diversity and inclusion and employee development.[2080] According to PG&E, the teams that make up the Talent Management function work to understand future workforce needs, identify and develop PG&E's future leaders, attract and retain the best talent available in the market and maximize employee performance.[2081] The Talent Management and Inclusion function is comprised of the following teams: the Performance and Inclusion team, which focuses on workforce diversity and inclusion policies, the EEO reporting and AA plan development and succession and performance management programs; Recruiting, which focuses on workforce planning, recruiting of new employees, internal employee job moves (other than bargaining unit movement based on the job bidding process), PG&E's Master of Business Administration (MBA) Program and relocation; Employee Development, which focuses on design and implantation of the Leadership Development program for high potential managers and directors, tuition refund administration, knowledge management, onboarding for new employees and their supervisors and career development programs; Workforce Development: Power Pathway,™ which does Career training

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[2075] Ex. 85 (DRA-17), p. 13, footnote 50 citing DRA_Oral010-19.

[2076] Ex. 85 (DRA-17), p. 13.

[2077] Ex. 39 (PG&E-9, workpapers), p. WP.4-2.

[2078] Ex. 38 (PG&E-9), p.4-4.

[2079] Ex. 85 p. 17.

[2080] Ex. 38 (PG&E-9), p.4-3.

[2081] Ex. 38 (PG&E-9), p.4-4.

and workforce development program, design and implementation; and HR Placement and Employment Support, which does represented employee job bidding and movement and Department of Transportation (DOT) drug testing.[2082]

PG&E recorded 114 FTE's in 2011 and 121 FTE's for 2012,[2083] or an increase of 7 new employees from 2011 to 2012. PG&E states "The HR department plans to add recruiters to support the Company's increased hiring and provide additional support for the Knowledge Transfer, Director and Manager Training and Workforce Planning programs."[2084] PG&E developed its forecast by utilizing 2011 staffing levels and then forecasting any needed increases in department services for Labor and Non-Labor. PG&E escalates these forecasts through 2012, 2013, and 2014.[2085]

PG&E requests 9 new employees in its 2014 forecast. PG&E has not justified adding 9 new FTEs in addition to the 7 new employees already added in 2012.[2086] The 2012 recorded expense level is most indicative of what PG&E is currently spending. For 2014, DRA recommends using the PG&E employee headcount from 2012. DRA recommends using 2012 recorded expense of $11.7 million for Account 920, escalated by roughly 3% per year for two years, for a total of $19.38 million in TY 2014.[2087]

9.4.3 Human Resources Technology Projects

PG&E forecasts $3.8 million for HR Technology Projects in 2014. DRA's recommendation is $198,000.[2088] For capital expenditures, PG&E forecasts $8.9 million in 2012, $2.7 million in 2013, and $6.7 million in 2014. DRA recommends $9.4 million in 2012, $3.3 million in 2013 and $2.9 million in 2014.[2089]

[2082] Ex.38 (PG&E-9), p.4-4.

[2083] Ex. 38 (PG&E-9), p.4-4.

[2084] Ex. 38 (PG&E-9), p.4-4.

[2085] Ex. 85 (DRA-17) p. 16, footnote 66, citing DR DRA 021-Q01.

[2086] Ex. 85 (DRA-17) p. 16, footnote 67, citing DR_DRA_Oral010-Q22Atch01.

[2087] Ex. 85 (DRA-17), p. 17.

[2088] Ex. 85 (DRA-17), p. 6, Table 17-4.

[2089] Ex. 85 (DRA-17), p. xx, Table 17-5.

9.4.3.1 General HR and Compliance

PG&E forecasts $1.1 million in expense and $600,000 in capital expenditures for 2014 for technology projects not assigned a specific HR function.[2090] Below, DRA discusses the results of its review of the projects whose costs DRA disputes.

9.4.3.2 HR Technology Legal and Regulatory

PG&E is forecasting $200,000 per year, beginning in 2014, to update its HR systems due to legal and regulatory changes.[2091] According to PG&E, each year laws and regulations change, requiring PG&E to update its HR systems to ensure that processes and outcomes stay compliant.[2092] PG&E gives as an example, that it "…expects the OFCCP[2093] to issue new regulations in late 2012 or early 2013 that will require system changes."[2094] In 2010 to 2011, the average cost for HR and Payroll was $445,000.

As DRA noted in its testimony, "[t]he information discussed above was the only information that PG&E provided about this project. PG&E provided no breakdown of costs associated with this project anywhere in its testimony or workpapers aside from WP 4-187 which only shows capital and expense forecast summaries. PG&E did not quantify any ratepayer cost savings associated with this project, nor did PG&E conduct any cost benefit analysis studies."[2095]

In Rebuttal, PG&E says that it disagrees with DRA's argument that PG&E did not provide sufficient information to justify this project. PG&E says that it:

> …often included information in testimony and data request responses beyond that which was described in DRA's report. In many cases, particularly for the larger technology projects, PG&E included project summaries in its workpapers that provided significantly more information regarding the business need for projects and the capabilities they would provide.[2096]

[2090] Ex. 85 (DRA-17), p. 19.

[2091] Ex. 38 (PG&E-9), p.4-33.

[2092] Ex. 38 (PG&E-9), p.4-33.

[2093] U.S. Department of Labor's Office of Federal Contract Compliance Programs (Ex. PG&E-9, p. 4-6).

[2094] Ex. 38 (P&E-9), p. 4-34.

[2095] Ex. 85 (DRA-17), p. 20.

[2096] Ex. 63 (PG&E-24), p. 3-8.

PG&E then gives, as an example, Workpaper pages 4-121 through 4-178. Actually, these workpapers illustrate DRA's point. The Workpapers are entitled "Project Summaries and Sample of IT Project Concept Estimate."[2097] None of the Project Summaries identifies any "cost savings" or "cost reductions."[2098] All appear to be wish list items whose costs are forecast based on PG&E's flawed "Concept Estimating Tool." True, PG&E's "Project Summaries" have more words in them than DRA's "brief description of them," but the length of PG&E's summaries is due to the repetitive, drawn out generalizations, rather than any informative substance.

Due to the vagueness and lack of support for the HR Legal and Regulatory Technology Projects, DRA continues to recommend no ratepayer funding.

9.4.3.3 HR Technology Enhancements

PG&E is forecasting $250,000 in expense and $100,000 in capital expenditures in 2014 for minor enhancements.[2099] According to PG&E, each year minor enhancements are required to support process changes or requirements.[2100] Examples of minor enhancements implemented in 2011 included an upgrade to the Organization Charting tool that is integrated with SAP, updated workflow to improve the process at the HR Service Center by allowing them to cancel, at the request of the department or HR Delivery, requests that have not yet been approved and are no longer needed, and encryption of the Remedy case management system database to protect Health Insurance Portability and Accountability Act covered data entered to document employee requests.[2101]

PG&E says that, over the past seven years, PG&E has implemented a series of major HR technology projects to replace legacy systems.[2102] Most necessary minor enhancements were

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[2097] Ex. 39 (PG&E 9 workpapers), p. WP 4-121.

[2098] *See, e.g.,* Ex. 39 (PG&E 9, workpapers), pp.WP 4-129 (HR Data Management and Archiving); WP 4-133 (Knowledge Management); WP 4-138 (E-Recruit Phase 2); WP 4-142 (Human Resources); WP 4-146 (Workforce Health & Productivity Service Delivery); WP 4-150); WP4-153 (Document Management); WP 4-173 (Knowledge Transfer).

[2099] Ex. 38 (PG&E-9), p.4-34.

[2100] Ex. 38 (PG&E-9), p.4-34.

[2101] Ex. 38 (PG&E-9), p.4-34.

[2102] Ex. 38 (PG&E-9), p.4-34.

included within the scope of major projects.[2103] Based on historical costs for individual enhancements and 10 SAP Human Capital Management modules currently implemented at PG&E, non-SAP applications and interfaces to other third-party systems, the forecasted $250,000 per year will allow up to two or three small enhancements to each system or interface.[2104]

As DRA noted in its testimony, the information related above was the only information PG&E provided about this project.[2105] PG&E provided no breakdown in direct testimony of what makes up the costs it attributes to this project aside from one page of workpapers, and that page only shows capital and expense forecast summaries.[2106] PG&E identified no ratepayer cost savings, and presented no cost- benefit analysis.

Due to the vagueness of the alleged ratepayer benefits and lack of support provided by PG&E, DRA continues to recommend no ratepayer funding for this project.

9.4.3.4 HR Mobile

PG&E is forecasting $500,000 in capital expenditures in 2014, and $120,000 in expense in 2014 for Mobile Applications.[2107] PG&E says that, as it increases its deployment of mobile technology to all employees, there is a growing demand for HR applications to be available to employees and supervisors working in the field.[2108] The forecast for this category encompasses the deployment of HR information and processes to mobile devices.[2109] PG&E says that the priority for mobile deployment "…will be those applications that can improve supervisors' and employees' ability to safely perform work, followed by those applications where efficiencies can be obtained."[2110] According to PG&E, one early mobile deployment will be the Qualification Tracker, which will allow a supervisor or other employees to determine if an employee is

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[2103] Ex. 38 (PG&E-9), p.4-34.

[2104] Ex. 38 (PG&E-9), p.4-34.

[2105] Ex. 85 (DRA-17), p.21.

[2106] Ex. 39 (PG&E-9 workpapers), p. WP 4-187.

[2107] Ex. 38 (PG&E-9), p.4-35.

[2108] Ex. 38 (PG&E-9), p.4-34.

[2109] Ex. 38 (PG&E-9), p.4-34.

[2110] Ex. 38 (PG&E-9), p.4-34.

qualified to perform specific work.[2111] PG&E says it is also planning to provide tablet computers to PG&E Academy employees who complete field assessments of employees.[2112] With tablet computers, the employees performing field assessments will be able to remotely update employee assessments, which will also update the employees' training history and qualifications tied to the specific assessment.[2113]

At this time, DRA does not disagree with this proposed project, but because PG&E based its estimate on its flawed Concept Estimating Tool, DRA recommends the Commission reduce PG&E's 2014 forecast by 14%.[2114]

9.4.3.5 HR Data Management and Archiving

PG&E forecasts $495,000 expense in 2014 for a project with the objective of moving historical employee data into a structured system where it can be accessed and maintained in accordance with all data governance requests.[2115] PG&E continues to house historical employee data in systems that have otherwise been retired.[2116] No new information or transactions are recorded in these systems. PG&E says that, with the deployment of new systems, data volumes have grown large enough that an archiving strategy is necessary.[2117] The objective of this project will be to move data into a structured system where it can be accessed and maintained in accordance with all data governance requirements.[2118] After the archiving work process is complete, PG&E intends to retire specific hardware and applications within the appropriate IT budget.[2119]

PG&E provided no breakdown in direct testimony of what makes up the costs it attributes to this project aside from one page of workpapers, and that page only shows capital and expense

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[2111] Ex. 38 (PG&E-9), p.4-34.

[2112] Ex. 38 (PG&E-9), p.4-34.

[2113] Ex. 38 (PG&E-9), p.4-34.

[2114] See Section 7 of this Opening Brief, above.

[2115] Ex. 38 (PG&E-9), p.4-35.

[2116] Ex. 38 (PG&E-9), p.4-35.

[2117] Ex. 38 (PG&E-9), p.4-35.

[2118] Ex. 38(PG&E-9), p.4-35

[2119] Ex. 38 (PG&E-9(, p.4-35

forecast summaries.[2120] PG&E identified no ratepayer cost savings, and presented no cost-benefit analysis. PG&E's only justification is nebulous "non-cost" savings"[2121] that cannot be quantified or verified.

Due to the vagueness of the alleged ratepayer benefits, and lack of support for this project, DRA recommends no ratepayer funding for this project.

9.4.3.6 Enterprise Integrated Help and Usage Tracking

PG&E forecasts $400,000 in capital expenditures and $80,000 expense in 2015 for funding to develop application and transaction-specific help information for users and provide "context sensitive help" in PG&E's SAP environment.[2122] PG&E's request does not impact the 2014 test year forecast, so DRA recommends no ratepayer funding for this project in the TY 2014 revenue requirement.

9.4.3.7 Integrated Competencies

PG&E is forecasting $300,000 in capital expenditures and $65,000 in expense in 2016 for a project which seeks to implement a technology to allow managers and employees to have an integrated picture of an employee's competencies.[2123] PG&E's request does not impact the 2014 test year forecast, so DRA recommends no ratepayer funding for this project in the TY 2014 revenue requirement.

9.4.3.8 Discipline Tracking System

PG&E forecasts $100,000 in capital expenditures and $23,000 in expense in 2016 for a plan which seeks to implement a discipline tracking system to improve consistency and provide visibility and reporting disciplinary issues.[2124] PG&E's request does not impact the 2014 test year forecast,[2125] so DRA recommends no ratepayer funding for this project in the TY 2014 revenue requirement .

[2120] Ex. 39 (PG&E-9 workpapers), p. WP 4-124.

[2121] Ex. 39 (PG&E-9 workpapers), p. WP 125.

[2122] Ex. 38 (PG&E-9), p.4-35.

[2123] Ex. 38 (PG&E-9), p.4-36.

[2124] Ex. 38 (PG&E-9), p.4-36.

[2125] HRG Ex. 85 (DRA-17), p. 24.

9.4.3.9 HR Document and Information Management

PG&E forecasts $500,000 in capital expenditures and $275,000 in expense in 2014 for an updated HR Document management system.[2126] PG&E currently has one online repository for electronic personnel records, but says that the system has limited capabilities and does not house all employee records.[2127] PG&E asserts that an updated HR Document management system will allow PG&E to improve employee-related record keeping, provide quicker access to needed records and foster the integration with SAP (PG&E's primary HR system).[2128] PG&E developed the forecast costs for this project using the Company's application development concept estimating tool.[2129]

The information discussed above was the only information that PG&E provided about this project. PG&E provided no breakdown in direct testimony of what makes up the costs it attributes to this project aside from one page of workpapers, and that page only shows capital and expense forecast summaries.[2130] PG&E identified no ratepayer cost savings, and presented no cost- benefit analysis. PG&E's only justification is a vague promise of "non-cost" savings"[2131] that cannot be quantified or verified.

Due to the vagueness and lack of support for this project, DRA continues to recommend no ratepayer funding for it.

9.4.3.10 Knowledge Management

PG&E forecasts $800,000 in capital expenditures for 2015 and 2016, and $400,000 in expense over two years beginning in 2015 for its plans to develop an improved knowledge management system to store and track non-employee specific documents, such as paper training rosters, labor agreements and HR policy documents in a secure, easy to use, web based system.[2132]

[2126] Ex. 38 (PG&E-9), p.4-37.

[2127] Ex. 38 (PG&E-9), p.4-37.

[2128] Ex. 38 (PG&E-9), p.4-37.

[2129] Ex. 38 (PG&E-9), p.4-37.

[2130] Ex. 39 (PG&E-9 workpapers), p. WP 4-124.

[2131] Ex. 39 (PG&E-9, workpapers), p. WP 153.

[2132] Ex. 38 (PG&E-9), p.4-37.

PG&E's request does not impact the 2014 test year forecast, so DRA recommends no ratepayer funding for this project in the TY 2014 revenue requirement .

9.4.3.11 HR Reporting and Analytics – HR Business Intelligence Projects

PG&E forecasts $150,000 in expense and $750,000 in capital expenditures in 2014 for a project which it says will focus on development of new or enhanced reports, as well as updates to data models or specific reports required as a result of the upgrade of the business Intelligence (BI) platform.[2133] According to PG&E, this project will also increase the reports and employee specific information made available to leaders. The costs associated with the upgrade of the BI hardware and software, other than HR specific report updates, are not part of this request. PG&E developed the forecast costs for this project using the Company's application development concept estimating tool.[2134]

As DRA noted in its testimony, the information related above was the only information that PG&E provided about this project.[2135] PG&E provided no breakdown in direct testimony of what makes up the costs it attributes to this project aside from one page of workpapers which only shows capital and expense forecast summaries.[2136] PG&E did not quantify any ratepayer cost savings associated with this project, nor did PG&E conduct any cost benefit analysis studies.

Due to the vagueness of the alleged ratepayer benefits, and lack of support for this project, DRA continues to recommend no ratepayer funding for it.

9.4.3.12 Talent Management Technology Projects

E-Recruit Phase 2

PG&E forecasts $240,000 in expense and $1.2 million in capital expenditures in 2014 for replacing the applicant tracking system in 2012 with SAP E-Recruit software.[2137] The first phase

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[2133] Ex. 38 (PG&E-9), p.4-37.

[2134] Ex. 38 (PG&E-9), p.4-37.

[2135] Ex. 85 (DRA-17), p. 27.

[2136] Ex. 39 (PG&E-9, workpapers), p. WP-187.

[2137] Ex. 38 (PG&E-9), p.4-38.

of the E-Recruit project is forecast to cost $3.2 million in capital and $557,000 expense in 2011 and 2012.[2138] DRA recommends no ratepayer funding for this project.

PG&E says the E-Recruit Phase 2 project includes specific additional functions that were not part of the initial Phase 1 E-Recruit project.[2139] The enhancements include automating offer letters, with approvals based on the Company's delegation authority; automated tracking of Affirmative Action Plans and Aspirational Hiring Goals; and the implementation of an employee referral program. PG&E developed the forecast costs for this project using the Company's application development concept estimating tool.[2140]

PG&E asserts "In order to fully realize the benefits of this project, additional functionality must be completed in the Phase 2 E-Recruit project."[2141]

As DRA noted in its testimony, the information related above was the only information that PG&E provided about this project.[2142] PG&E provided no breakdown of costs associated with this project anywhere in its testimony or workpapers aside from WP 4-187, which only shows capital and expense forecast summaries. PG&E did not quantify any ratepayer cost savings associated with this project, nor did PG&E conduct any cost benefit analysis studies. PG&E is already receiving the benefits of the E-recruit project implemented in 2012, making another round of enhancements excessive and burdensome to ratepayers. PG&E did not provide enough information about this E-Recruit Phase 2 program to justify ratepayer funding of it.

Due to the vagueness and lack of support for this project, DRA recommends no ratepayer funding for this project.

Talent Integration

PG&E forecasts $150,000 in expense and $750,000 in capital expenditures in 2015 for a Talent Integration project that PG&E says will integrate succession planning, employee

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[2138] Ex. 38 (PG&E-9, p.4-38.

[2139] Ex. 38 (PG&E-9), p.4-38.

[2140] Ex. 38 (PG&E-9), p.4-38.

[2141] Ex. 39 (PG&E-9 workpapers), p. WP 4-134

[2142] Ex. 85 (DRA-17), p. 28.

development plans and learning, skills, and qualifications with recruitment and performance management.[2143]

PG&E's request does not impact the 2014 test year forecast, so DRA recommends no ratepayer funding for this project in the TY 2014 revenue requirement.

Onboarding

PG&E forecasts $155,000 in expense and $750,000 in capital expenditures in 2015 for the "Onboarding" project which PG&E says will provide an online process for new and prospective employees to complete benefits and other employee specific transactions.[2144] DRA recommends no ratepayer funding for this project.

PG&E says that, in its TY 2011 GRC, PG&E discussed the need to implement the tools that would automate the onboarding process and the project was subsequently deferred in order to address compliance concerns with PG&E's tracking system.[2145] The company claims that there is still a need to automate the onboarding process to improve efficiency.[2146] Specifically, the project will enable future employees to securely log onto the PG&E employee portal to complete required forms and receive electronic information regarding their future employment at PG&E.[2147] PG&E developed the forecast costs for this project using the Company's application development concept estimating tool.[2148]

As DRA noted in its testimony, the information discussed above was the only information that PG&E provided about this project.[2149] PG&E provided no breakdown of costs associated with this project anywhere in its testimony or workpapers aside from WP 4-187 which only shows capital and expense forecast summaries. PG&E did not quantify any ratepayer cost savings associated with this project, nor did PG&E conduct any cost benefit analysis studies. If the employees are already given company's emails, DRA sees no reason for a specific employee

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[2143] Ex. 38 (PG&E-9), p. 4-39.

[2144] Ex. 38 (PG&E-9), p. 4-39.

[2145] Ex. 38 (PG&E-9), p. 4-39.

[2146] Ex. 38 (PG&E-9), p. 4-39.

[2147] Ex. 38 (PG&E-9), p. 4-39.

[2148] Ex. 38 (PG&E-9), p. 4-39.

[2149] Ex. 85 (DRA-17), p. 29.

portal. Job bulletins and required forms can easily be sent through email. Moreover, since PG&E deferred this project from the last GRC, it clearly is not a priority.

Due to the vagueness and lack of support for this project, and the fact that it does not impact the 2014 Test Year, DRA continues to recommend no ratepayer funding for the Onboarding project.

Workforce Planning

PG&E is forecasting $800,000 in capital expenditures in 2014, and $50,000 in expense in 2014 for Workforce Planning, which PG&E says will enhance the current workforce planning tool to become a more robust workforce modeling tool.[2150] PG&E developed the forecast costs for this project using the Company's application development concept estimating tool.[2151]

At this time, DRA does not disagree with this proposed project, but because PG&E based its forecast on its flawed Concept Estimating Tool, DRA recommends the Commission reduce PG&E's 2014 forecast by 14%.[2152]

9.4.3.13 Workforce Health and Productivity Technology

Annual Open Enrollment

PG&E forecasts $575,000 in 2014 expenses for updating its systems to reflect benefit plan changes, rate changes, new or revised federal, state and local regulations regarding benefit plan administration.[2153] DRA recommends no ratepayer funding for this project.[2154]

According to PG&E, "each year, PG&E must update its systems to reflect benefit plan, rate changes."[2155] Beyond that statement, PG&E provided little information about this project. PG&E provided no breakdown of the costs associated with this project anywhere in its testimony or workpapers aside from WP 4-187, which only shows capital and expense forecast summaries. PG&E did not quantify any ratepayer cost savings associated with this project, nor did PG&E conduct any cost benefit analysis studies. In addition, PG&E already has embedded costs

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[2150] Ex. 38 (PG&E-9), p. 4-40.

[2151] Ex. 38 (PG&E-9), p. 4-40.

[2152] Ex. 85 (DRA-17), p. 30.

[2153] Ex. 38 (PG&E-9), p. 4-40.

[2154] Ex. 85 (DRA-17), p. 31.

[2155] Ex. 38 (PG&E-9), p. 4-40.

associated with updating its systems to reflect benefit plan changes, rate changes, new or revised federal, state and local regulations regarding benefit plan administration.

For all these reasons, DRA continues to recommend no ratepayer funding for this project.

Paperless Benefit Processing

PG&E forecasts $100,000 in expense and $500,000 in capital expenditures in 2015 for Paperless Benefits Processing, which PG&E says will enhance PG&E's existing self-service and web-based systems to provide complaint Summary Plan documents to all employees and allow employees and retirees to choose electronic delivery of these documents.[2156] In addition to providing employees and retirees with on- demand access to these important documents, this project is estimated to save $240,000 in printing and mailing costs every three years.[2157] PG&E developed the forecast costs for this project using the Company's application development concept estimating tool.

PG&E's request does not impact the 2014 test year forecast, so DRA recommends no ratepayer funding for this project in the TY 2014 revenue requirement.

Workforce Health and Productivity Service Delivery

PG&E forecasts $140,000 in expense and $700,000 in capital expenditures in 2014, for an SAP update and other ancillary systems to support the anticipated changes and to build, test and deploy the new interfaces that would be required as part of a new benefits service delivery model.[2158] DRA recommends no ratepayer funding for this project.

PG&E says it is evaluating alternative methods of administering its retirement plans, including retiree medical open enrollment.[2159] For example, PG&E says it expects that employees choosing the new cash balance retirement plan will have more options and need to access to resources with more expertise than is currently available in the HR Service Center.[2160] PG&E also says it is exploring the option of including its retirees in a medical plan exchange that

[2156] Ex. 38 (PG&E-9), p.4-40.

[2157] Ex. 38 (PG&E-9), p.4-40.

[2158] Ex. 38 (PG&E-9), p.4-41.

[2159] Ex. 38 (PG&E-9), p.4-41.

[2160] Ex. 38 (PG&E-9), p.4-41.

could significantly reduce the medical premium costs paid by retirees.[2161] PG&E developed the forecast costs for this project using the Company's application development concept estimating tool.

As DRA noted in its testimony, the information related above was the only information that PG&E provided about this project.[2162] While PG&E says a goal of this project is to "reduce premiums to retirees," DRA notes there is no mention of any savings to ratepayers. PG&E provided no breakdown of costs associated with this project anywhere in its testimony or workpapers aside from WP 4-187, which only shows capital and expense forecast summaries. PG&E did not quantify any ratepayer cost savings associated with this project, nor did PG&E conduct any cost benefit analysis studies. In addition, PG&E already has embedded costs associated with building, testing and deploying new SAP interfaces.

In a data request to DRA, PG&E asked DRA to "[s]tate all facts that DRA relies on to support its contention that PG&E has embedded costs associated with building, testing and deploying new SAP interfaces."[2163] DRA's response was, and still is, that:

> c. DRA's reference to 'embedded funding is to the funds PG&E is currently collecting from its ratepayers and included in recorded costs. The embedded funding to which DRA is taken from PG&E's testimony, Ex. PG&E-9, Chapter 4, Tables 4-4 and 4-5, showing 2011 Human Resources Information and Technology expense and capital costs.
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> d. DRA "….relies for tis contention that PG&E has embedded costs associated with building, testing and deploying new SAP interfaces" on the fact that DRA found no explanation or analysis in PG&E's testimony or workpapers that shows why PG&E's current funding level, at which it currently administers its retirement plans, is insufficient to allow PG&E to update "SAP and other ancillary systems."[2164]

[2161] Ex. 38 (PG&E-9), p.4-41.

[2162] Ex. 85 (DRA-17), p. 32.

[2163] Ex. 63, (PG&E), p. A-187.

[2164] Ex. 63 (PG&E-24), p. A-187.

PG&E's request of nearly $2.4 million in capital just to "evaluate" alternate methods of administering retirement plans is an unjustified and excessive burden to ratepayers. DRA continues to recommend no ratepayer funding for this project.

9.4.3.14 Labor Relations Technology Projects – Annual Support for Negotiated Changes

PG&E forecasts $550,000 in expense in 2014 for Annual Support for Negotiated Changes.[2165] Each year PG&E negotiates agreements with the three unions that represent over 13,500 employees.[2166] As PG&E has implemented technology to replace manual processes, these agreements sometimes require PG&E to make updates to its systems to reflect new wages, working conditions or other terms.[2167] The forecasted funding for this project does not include the annual changes for the benefit plans which are included under the technology projects in the Workforce Health and Productivity section.[2168]

The information discussed above was the only information that PG&E provided about this project. PG&E provided no breakdown in direct testimony of what makes up the costs it attributes to this project aside from one page of workpapers, and that page only shows capital and expense forecast summaries.[2169] PG&E identified no ratepayer cost savings, and presented no cost- benefit analysis.

DRA continues to recommend no ratepayer funding for this project.

9.4.3.15 HR Deliver Technology Costs Enhance Case Management Tool

PG&E forecasts $60,000 in expense and $300,000 in capital expenditures in 2014 for PG&E's Enhance Case Management Tool.[2170] DRA recommends the Commission reduce PG&E's TY 2014 forecast by 14%.[2171]

[2165] Ex. 38 (PG&E-9), p. 4-42.

[2166] Ex. 38 (PG&E-9), p. 4-42.

[2167] Ex. 38 (PG&E-9), p. 4-42.

[2168] Ex. 38 (PG&E-9), p. 4-42.

[2169] Ex. 39 (PG&E-9 workpapers), p. WP 4-124.

[2170] Ex. 39 (PG&E-9 workpapers), p. WP 4-42.

[2171] Ex. 85 (DRA-17), p. 30.

PG&E's HR Service Center and other HR employees use a case management system to track all employee and retirees calls and requests.[2172] This system provides a record of calls made to the HR Service Center, particularly who made the request and the nature of the request.[2173] PG&E says that its current HR case management system is a standalone system and is not integrated with PG&E's voice, email, or electronic employee records systems.[2174] PG&E says this project will integrate the case management system with other functionality and allow PG&E to have a single, secure, and complete source for employee requests and to easily track specific transactions or employee events. PG&E developed the forecast costs for this project using the Company's application development concept estimating tool described in PG&E.[2175]

At this time, DRA does not disagree with this proposed project, but because PG&E based its forecast on its faulty Concept Estimating Tool, DRA recommends that the Commission reduce PG&E's 2014 forecast by 14%.

Employee and Manager Self-Service Enhancement

PG&E forecasts $350,000 in expense and $1.8 million in capital expenditures in 2014 for Employee and Manager Self-Service Enhancements.[2176] DRA recommends no ratepayer funding for this project.[2177]

PG&E says this project is to implement additional employee and manager self-service tools and re-launch PG&E's employee portal.[2178] PG&E says this project will improve the usability of its employee and retiree self service functions, which it expects to reduce the number of transactions and transactional questions handled by HR Delivery representatives.[2179] PG&E says that this project was requested initially in the 2011 GRC, and then was deferred in order ".to address compliance concerns with PG&E's applicant tracking system."[2180]

[2172] Ex. 38 (PG&E-9), p.4-42.

[2173] Ex. 38 (PG&E-9), p.4-42.

[2174] Ex. 38 (PG&E-9), p.4-42.

[2175] Ex. 38 (PG&E-9), p.4-42.

[2176] Ex. 63 (PG&E-24), p.3-2, Table 3-1 and p. 3-3, Table 3-2.

[2177] Ex. 85, p. 35.

[2178] Ex. 38 (PG&E-9), p.4-42.

[2179] Ex. 38 (PG&E-9), p.4-42.

[2180] Ex. 38 (PG&E-9), p.4-42.

As DRA noted in its testimony, the information discussed above was the only information that PG&E provided about this project.[2181] PG&E provided no breakdown of the costs associated with this project anywhere in its testimony or workpapers aside from WP 4-187, which only shows capital and expense forecast summaries. PG&E did not quantify any ratepayer cost savings associated with this project, nor did PG&E conduct any cost benefit analysis studies.

DRA continues to recommend no ratepayer funding for this project.

9.4.3.16 Compensation Technology Costs

Rewards and Recognition Tool

PG&E forecasts $250,000 in expense in 2016 for its Rewards and Recognition Tool.[2182] PG&E's request does not impact the 2014 test year forecast, so DRA recommends no ratepayer funding for this project in the TY 2014 revenue requirement.[2183]

Compensation Data Management Upgrade

PG&E forecasts $50,000 in expense and $750,000 in capital expenditures in 2015 for Compensation Data Management Upgrade.[2184] PG&E's request does not impact the 2014 test year forecast, so DRA recommends no ratepayer funding for this project in the TY 2014 revenue requirement.[2185]

Total Compensation Statement

PG&E forecasts $100,000 in expense in 2015 for Total Compensation Statement.[2186] PG&E's request does not impact the 2014 test year forecast, so DRA recommends no ratepayer funding for this project in the TY 2014 revenue requirement.[2187]

[2181] Ex. 85 (DRA-17) p. 35.

[2182] Ex. 85 (PG&E-9), p.4-43.

[2183] Ex. 85 (DRA-17), p. 36.

[2184] Ex. 38 (PG&E-9), p.4-43.

[2185] Ex. 85 (DRA-17), p. 36.

[2186] Ex. 38 (PG&E-9), p.4-44.

[2187] Ex. 85 (DRA-17), p. 37.

Career Tracks Phase 2

PG&E forecasts $325,000 in expense and $500,000 in capital expenditures in 2016 for Career Tracks Phase 2.[2188] PG&E's request does not impact the 2014 test year forecast so DRA recommends no ratepayer funding for this project in the TY 2014 revenue requirement.[2189]

9.4.3.17 PG&E Academy Technology Costs

Qualifications Tracking Enhancements

PG&E forecasts $300,000 in expense beginning in 2014 for Qualifications Tracking Enhancements.[2190] DRA recommends no ratepayer funding for this project.[2191]

PG&E says this project will provide real-time evaluation of an employee's specific qualifications and qualification gaps for new or forecasted work as well as additional enhancements to the gas and electric qualifications programs.[2192] PG&E also says that this project will include additional reporting and integration with other systems or SAP modules (such as Work Management).[2193] PG&E developed the forecast costs for this project using the Company's application development concept estimating tool.[2194]

As DRA noted in its testimony, the information related above is the only information that PG&E provided about this project.[2195] PG&E provided no breakdown of the costs associated with this project anywhere in its testimony or workpapers aside from WP 4-187 which only shows capital and expense forecast summaries. PG&E did not quantify any ratepayer cost savings associated with this project, nor did PG&E conduct any cost benefit analysis studies.

DRA continues to recommend no ratepayer funding for this project.

[2188] Ex. 38 (PG&E-9), p.4-44.

[2189] Ex. 85 (DRA-17), p. 37.

[2190] Ex. 38 (PG&E-9), p.4-45.

[2191] Ex. 85 (DRA-17), p. 38.

[2192] Ex. 38 (PG&E-9), p.4-45.

[2193] Ex. 38 (PG&E-9), p.4-45.

[2194] Ex. 38 (PG&E-9), p.4-45.

[2195] Ex. 85 (DRA-17), p. 38.

Integrate Learning and Qualifications with Payroll

PG&E is forecasting $60,000 in expense and $300,000 in capital expenditures in 2016 for Integrate Learning and Qualifications with Payroll.[2196] PG&E's request does not impact the 2014 test year forecast, so DRA recommends no ratepayer funding for this project in the TY 2014 revenue requirement.[2197]

9.5 Regulatory Relations Department Costs

PG&E's Regulatory Relations Department forecasts $22.477 million in Department Costs for Test Year 2014 GRC.[2198] PG&E also forecasts an additional $1.6 million in IT expenses for the Test Year. DRA recommends ratepayer funding of no more than $21.103 million.[2199] The areas in dispute are described below.

9.5.1 Regulation and Rates Department ((PCCs 10421, 10408, 10611, 13844, 13846, 13845, 13847, 13848, 13849, 14689)

PG&E is forecasting $16.5 million in its Test Year 2014 GRC for its Regulation and Rates Department.[2200] DRA recommends that the Commission reduce PG&E's request by $1.4 million to remove ratepayer funding of 9 new employees.[2201]

The Regulation and Rates Department manages PG&E's regulatory cases before the CPUC. PG&E says that this includes working with regulators and other stakeholders, conducting rate design and revenue data analyses, and ensuring compliance and reporting requirements are met.[2202] The Regulations and Rates Department consists of the following organizations: Vice President of Regulations and Rate's Immediate Office, which supervises the management of PG&E's regulatory cases and provides regulatory expertise to PG&E's Lines of Business; the Analysis and Rates Department, which provides regulatory analysis and revenue forecasts, calculates revenue requirements, and develops rates, rules and tariffs; Energy Proceedings

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[2196] Ex. 38 (PG&E-9), p. 4-45.

[2197] Ex. 85 (DRA-17), p. 38.

[2198] Ex. 63 (PG&E 24), p. 4-3, Table 4-1.

[2199] Ex. 85 (DRA-17), p. 39, Table 17-13.

[2200] Ex. 39 (PG&E-9, workpapers), p. WP 5-1

[2201] Ex. 85 (DRA-17), p. 42.

[2202] Ex. 38 (PG&E-9), p. 5-4.

Department, which manages regulatory proceedings and provides guidance for the development, approval, and implementation of regulatory filings for Energy Procurement (EP) and Customer Care Lines of Business; and the Operations Proceedings Department, which manages regulatory proceedings and provides guidance for the development, approval, and implementation of operations-related regulatory filings.

At the end of 2012, the Regulation and Rates Department consisted of 130.4 FTEs.[2203] PG&E plans to hire a total of 9 incremental staff in 2014 in the Regulation and Rates Department. In the Analysis and Rates department, PG&E plans to hire 5 new 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.[2204] In the Operations Proceedings Department, PG&E plans to hire three new Senior Case Managers and one new Case Coordinator to support an overall increase in the number of regulatory filings.[2205]

PG&E has not shown there is an immediate need and/ or urgency to hire 9 new employees in 2014, especially when this department already added 9 FTE's in 2012. This is an unjustified burden on ratepayers. PG&E has been operating sufficiently with the current number of FTES.

In Rebuttal, PG&E points to an increase in the number of regulatory filings, and in data requests to PG&E.[2206] Since PG&E did not provide this information in its Direct showing, it is impossible now to verify the information. In some respects, this new information shows how unjustified PG&E's request for new positions in the Regulatory Relations Department is.

Are ratepayers being asked to fund more regulatory positions so that PG&E can more easily seek more rate increases? Is the reason for the increase in data requests because PG&E is continually filing applications for rate increases that are not adequately supported?

In Rebuttal, PG&E also points to the fact that, in this GRC, DRA assigned three auditors for nine months, as opposed to one auditor in PG&E's TY 2011 for four months. One important

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[2203] DRA_Oral010-02Partial02

[2204] DRA_Oral011-07

[2205] DRA_Oral011-07

[2206] HRG Ex. 63, (PG&E-24) p. 4-5.

distinction between the two audits is the great concern, in this GRC, that no costs related to the San Bruno disaster be included in any way in rates.

DRA continues to recommend that the Commission reject PG&E's request for the incremental $1.4 million for 9 new employees.

9.5.2 State Agency Relations Department (PCCs 12706 and 13725)

PG&E is requesting $1.6 million in State Agency Relations Department for its Test Year 2014 GRC.[2207] DRA recommends PG&E forecast be reduced by $120,000 in consulting costs that PG&E failed to justify in its Direct testimony.[2208]

In its Workpapers, PG&E gives as its explanation of the variance between 2013 and 2014 of $120,000 the following: "Increase in consulting spend to bring back to near 2010 funding level. $120K was inadvertently missed during the prior year's budgeting cycle."[2209]

In Rebuttal, PG&E argues the $120,000 should be included. It is not possible at this late date to verify any of PG&E arguments, so DRA continues to oppose ratepayer funding of this unsupported $120,000. DRA recommends the Commission adopt a forecast of $1.5 million for PG&E's State Agency Relations Department.

9.5.3 Information Technology Projects

PG&E is requesting $1.6 million in IT expense and $2.2 million in capital expenditures in 2014 in capital expenditures for three technology projects: (1) Results of Operations Infrastructure; (2) Rate Design and Analysis; and (3) Enhancing Regulatory Relations Operations Tools.[2210] For the reasons discussed below, DRA recommends that the capital portion of the forecast for the Results of Operations Infrastructure project be reduced by 14%, and the expense portion be removed. DRA recommends no ratepayer funding for the Rate Design and Analysis, and Enhancing Regulatory Relations Operations projects.

[2207] Ex. 39 (PG&E-9, workpapers), p. WP. 5-2.

[2208] Ex. 85 (DRA-17), p. 45.

[2209] Ex. 39 (PG&E-9), p. WP. 5-69.

[2210] Ex. 38 (PG&E-9), p. 5-16.

9.5.3.1 Results of Operations Infrastructure Project

PG&E forecasts $150,000 in expense in 2014 and $600,000 in capital in 2014 and $600,000 in 2015 for its Results of Operations Infrastructure Project.[2211] The RO Infrastructure Project is the next phase following the Results of Operations Data management Project, which established a data management system that replaced individual and independent source files.[2212] 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.[2213] These RO models will allegedly have expanded capabilities to process large volumes of data, conduct increasingly complex analyses, streamline capital data flow from the internal SAP planning system, and introduce advanced tools to analyze stakeholder positions, spending trade-offs, and additional scenarios. PG&E developed the forecast costs for this project using the Company's application development concept estimating tool.[2214]

At this time, DRA does not disagree with this proposed project, but because PG&E based its estimate on its flawed Concept Estimating Tool, DRA recommends the Commission reduce PG&E's 2014 forecast by $84,000.[2215]

9.5.3.2 Rate Design and Analysis Infrastructure Project

PG&E forecasts $400,000 in expense in 2014, and $1.6 million in capital expenditures in 2014 for its Rate Design and Analysis Project.[2216] DRA recommends no ratepayer funding for this project.[2217]

PG&E says the Rate Design and Analysis Project is a continuation of the Electric Rate Design Model Replacement Project which begun in 2012.[2218] This next phase supposedly enhances electric and gas rate design models to ensure accuracy, effectiveness, and ease of

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[2211] Ex. 38 (PG&E-9), p. 5-17

[2212] Ex. 38 (PG&E-9), p. 5-16

[2213] Ex. 38 (PG&E-9), p. 5-16

[2214] Ex. 39 (PG&E-9, workpapers), p. WP. 5-85

[2215] Ex. 85 (DRA-17), p. 47.

[2216] Ex. 38 (PG&E-9), p. 5-17.

[2217] Ex. 85 (DRA-17), p. 48.

[2218] Ex.38 (PG&E-9), p. 5-17.

understanding.[2219] In particular, the project is supposed to add further capabilities in the rate design and analysis process, including the automation of data flow in rate models, automation of interval data analysis and reporting, upgrade of key electric rate models to use interval data, expansion of bill analyses capabilities to handle future rate options, ability to perform what-if analyses, and more easily generate CPUC-approved information release for community choice aggregators and local governments.[2220]

PG&E has always had a budget for rate design and analysis projects. PG&E has not shown that its embedded funding is inadequate to continue to provide accurate and effective rate design models. If this is a new type of cost, then Ordering Paragraph 37 in the Commission's decision on PG&E's last GRC requires PG&E to estimate and include in the revenue requirement the cost savings to be achieved by the new type of cost or an explanation of the reasons there will be no cost savings. If this is not a new type of cost, then PG&E needs to show why the embedded funding it already receives is insufficient.[2221] PG&E's Direct testimony fails to meet either requirement. PG&E's arguments in its Rebuttal testimony come too late to be verified. DRA, therefore continues to recommend no ratepayer funding for this project.

9.5.3.3 Enhancing Regulatory Relations Operations Tool

PG&E forecasts $1,050,000 in expense for Enhancing Regulatory Relations Operations Tools project in its Test Year 2014 GRC.[2222] DRA recommends no ratepayer funding for this project.[2223]

PG&E says its Enhancing Regulatory Relations Operations Tools initiative consists of two components: 1) enhancements to the net Tools suite WebDocs; and replacement of Tariff Management (TM2).[2224] Previous improvements to netTools suite, WebDocs, and TM2 have enabled Regulatory Relations' employees to perform their work more effectively by automating the oversight of approximately 300 active projects, 1,000 compliance items, and thousands of

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[2219] Ex. 38 (PG&E-9), p. 5-17.

[2220] Ex. 38 (PG&E-9), p. 5-17.

[2221] Ex. 63 (DRA-24), Appendix A, p. A-192, DRA Response to PG&E-DRA-52, A.1.

[2222] Ex. 38 (PG&E-9), p. 5-18.

[2223] Ex. 85 (DRA-17), p. 49.

[2224] Ex. 38 (PG&E-9), p. 5-17.

discovery requests annually.[2225] PG&E says that the following projects are expected to expand on those previous improvements: Updates and maintenance of the netTools Suite and WebDoc, which require maintenance, upgrades, and enhancements to continue to meet evolving regulatory needs and Replacement of Tariff Manager 2, which will replace the desktop based software system and "potentially" integrate with some features of the Company's Enterprise Records management System.[2226]

As DRA noted in its testimony, the information related above was the only information that PG&E provided about this project. PG&E provided no breakdown of the costs associated with this project anywhere in its Direct testimony or workpapers aside from WP 5-93 to 5-96 which only show forecast summaries. PG&E did not quantify any ratepayer cost savings associated with this project, nor did PG&E conduct any cost benefit analysis studies. DRA continues to recommend no ratepayer funding for this project.

9.6 Law Department and Related Costs

PG&E's forecast for its "Law Department and Related Costs" includes the Law Department, the General Counsel's Immediate Office, and the Information Management Compliance Department. Collectively, these are all referred to as the Law Department.

PG&E is forecasting Law Department costs of $51.733 million in 2014, which is 5.6% less than the 2011 recorded adjusted amount of $54.778 million.[2227] PG&E says that "[t]he primary changes to the forecast are escalation of wages for the Law Department employees and a reduction in forecasted outside services."[2228]

PG&E is forecasting $21.125 million in 2014 for settlements and judgments and $14.888 million for third-party claims payments.'[2229]

PG&E is also forecasting two IT projects the Law Department for 2014-2016: the Legal eDiscovery Program, and the Public and Employee Safety and Claims Management Program.

[2225] Ex. 38 (PG&E-9), p. 5-17.

[2226] Ex. 38 (PG&E-9), p. 5-17.

[2227] Ex. 38 (PG&E-9), p. 6-12, Table 6-1.

[2228] Ex. 38 (PG&E-9), 6-1.

[2229] PG&E says that Settlements, Judgments, Third-Party Claims are exclusive of San Bruno claims. (Ex. 38 (PG&E-9), pp. 6-9, 6-10.)

For these projects, PG&E forecasts $664,000 in expenses in 2014, $60,000 in capital expenditures for 2013, $890,000 for 2014, $1.27 million for 2015, and $750,000 in capital for 2016. PG&E developed the cost forecast for each IT project using PG&E's application development concept estimating tool.[2230]

The areas where DRA disputes PG&E's forecasts are discussed below.

9.6.1 Litigation/ Settlements and Third Party Claims

The Law Department records two types of costs in Account 925 -- Injuries and Damages: (1) settlements and judgment costs, as part of the litigation function, and (2) claims payments to third parties alleging personal injury, property damage and economic loss as a result of PG&E's operations.[2231] According to PG&E, all costs related to the San Bruno disaster have been excluded from PG&E's 2014 GRC.[2232]

The Law Department is forecasting $36.013 million in Litigation/ Settlements and Third Party Claims expenses for 2014, a 24.39% increase from 2011 adjusted recorded costs of $48.839 million.[2233]

9.6.1.1 Settlements and Judgments

PG&E forecasts 2014 Settlements and Judgments expenses for its Law Department in the amount of $21.125 million, a 42.7% decrease from 2011 adjusted recorded costs of $36.870 million. DRA recommends a test year 2014 forecast for Settlement and Judgments of $19.567 million.[2234]

PG&E's forecast is based on a four-year average of adjusted actual costs for 2008-2011. PG&E's Settlement and Judgment adjusted costs for 2008-2011 totaled $84.5 million, and averages to $21.125 million. PG&E's adjusted costs for 2007-2011 include settlements for employment litigation of approximately $6.380 million. DRA recommends that costs related to employment and discrimination cases should be removed before forecasting for the Test Year 2014. This is consistent with long-standing Commission.

[2230] Ex. 30 (PG&E-7), Chapter 8.

[2231] Ex. 38 (PG&E-9), p. 6-9.

[2232] Ex. 38 (PG&E-9), p. 6-9.

[2233] Ex. 39 (PG&E-9, workpapers), p. WP 6-83.

[2234] Ex. 84 (Ex. DRA-16), p. 54.

When an employment or discrimination case either results in a judgment against the utility or the utility chooses to settle such a case, the costs incurred by the utility should not be borne by the ratepayers. In 1980, FERC issued an Accounting Release (AR) 12 which specifically questions:

> What is the proper accounting treatment for expenditures made by the utility, resulting from employment practices that were found to be discriminatory by a judicial or administrative decree or that were the result of a compromise settlement or consent decree?

The FERC Release AR-12 answers the question by stating:

> The Uniform System of Accounts provides that all charges to utility operating expenses accounts must be just and reasonable. Expenditures of the nature mentioned above that can be readily identified and quantified should not be considered as just and reasonable charges to utility operations and should be classified to the appropriate non-operating expense accounts.

To DRA's knowledge, this Commission has followed AR-12 since it was issued. In D.92549, the Commission decided to exclude from test year results all costs which SCE incurred in an affirmative action suit which the Commission assumed would shortly be settled, explaining the position was in harmony with FERC in AR-12.[2235] In D. 96-01-011, the Commission, again held that costs incurred in meritorious employment discrimination suits should not be charged to ratepayers as they are non-operating expenses.[2236] In its most recent GRC, SCE asked the Commission again to change the policy. The Commission reaffirmed the policy stating:

> As to settlement of discrimination claims, we decline to alter our longstanding policy on this issue because the risks of a potentially adverse verdict still drive any settlement. Unchecked ratepayer recover could result in a loss of vigilance in preventing discriminatory practices.[2237]

DRA has removed a total of $6.380 million from 2008 through 2011 adjusted recorded costs. After removing these costs DRA calculates a four average of $17.759 million. Therefore, DRA recommends that $1.372 million be removed from test year 2014 forecast of $19.754 million.

[2235] *SoCal Edison Company* (1980) 5 CPUC 2d 39; D.92549; 1980 Cal PUC Lexis 1296*48.

[2236] *In Re Southern California Edison Company (*1996) D. 96-01-011, 1996 Cal CPUC LEXIS 23.

[2237] *Decision on Test Year 2012 General Rate Case for Southern California Edison Company* (2012) D.12-11-051, mimeo, pp. 491-492.

9.6.1.2 Third Party Claims

The Law Department is forecasting $14.888 million in 2014, a 24.39% increase from 2011 adjusted recorded costs of $11.969 million.[2238] DRA recommends a test year 2014 forecast for Third Party Claims of $14.649 million.

PG&E says that the Law Department has adjusted out cases and issues, including costs related to the San Bruno disaster.[2239] PG&E's forecast is based on a four year average of adjusted actual costs for 2008-2011. PG&E's Third Party Claims adjusted costs for 2008-2011 totaled $59.644 million and averages to $14.888 million. PG&E's 2012 recorded costs, adjusted for San Bruno,[2240] were 6% less than PG&E's forecast of $14.888 million. DRA recommends the Commission use a four year average (2009-2012) which results in a forecast of $14.649 million.

9.6.2 Law Information Technology Projects

PG&E forecasts two IT projects for the Law Department in 2014: the Legal eDiscovery Program, and the Public and Employees Safety and Claims Management Program.[2241] PG&E's TY 2014 forecast is for $664,000 in expenses, and $890,000 in capital expenditures.

PG&E based its forecasts for both IT projects on its "Concept Estimating" tool. DRA has doubts about the accuracy of the estimates of this "tool", as discussed in more detail in Section 7 of this Opening Brief. Based on those concerns, DRA recommends that the Commission remove $93,000 from PG&E's expense TY 2014 estimate, and $8,000 from PG&E's capital 2013 forecast, and $125,000 from PG&E's capital 2014 forecast for Law Information Technology Projects.[2242]

9.7 PG&E Corporation and Executive Offices; and Corporate

PG&E is forecasting costs for PG&E Corporation and Executive Offices and the Corporate Secretary Department of $13.8 million in 2014, a 10% increase from the 2011

[2238] Ex. 38 (PG&E-9), p. 6-9.

[2239] Ex. 38 (PG&E-9), p. 6-9.

[2240] Ex. 84 (DRA-16), p. 56, citing response to DRA-PG&E-111, Q. 1 Supplemental 1 Confidential.

[2241] Ex. 38 (PG&E-), p. 6-10.

[2242] Ex. 84 (DRA-16), p. 57.

adjusted recorded costs of $12.5 million.[2243] [2244] In addition, PG&E is forecasting Directors Fees and Expenses of $1.617 million in 2014, a 3% increase from the 2011 adjusted recorded costs of $1.566 million. The increase is due to the anticipated addition of one Board member by 2014, and an increase in quarterly retainer amounts.

The areas where DRA disputes PG&E's forecasts are discussed below.

9.7.1 Chairman, CEO and President's Office

In September 2011, PG&E Corporation's Board of Directors elected Mr. Anthony F. Earley, Jr. as Chairman of the Board, Chief Executive Officer (CEO) and President of PG&E Corporation. PG&E is forecasting $4.619 million, a 1.2% increase from 2011 adjusted recorded costs of $4.565 million.[2245]

DRA recommends that $735,179 be removed from PG&E's Chairman, CEO and President's Office test year 2014 forecast. PG&E's 2012 recorded costs were $2,936 million,[2246] or 35% lower than PG&E's 2012 forecast of $4.551 million. Since PG&E's 2012 forecast was clearly overstated, DRA recommends the Commission use a three-year average, 2010-2012, to calculate the test year 2014 forecast. A three-year average results in a test year 2014 forecast of $3.884 million.

9.7.2 President's Office

PG&E's Executive Office is comprised of the immediate office of PG&E's President, the Utility Strategic Planning group, and the Utility Performance Improvement Department.[2247] PG&E's President's Office is forecasting $4.785 million of expenses in 2014, a 29.68% increase from 2011 adjusted recorded costs of $4.277 million.[2248]

[2243] Ex. 38 (PG&E-9), p. 7-2.

[2244] Ex. 38 (PG&E-9), 7-2.

[2245] Ex. 84 (DRA-16), p. 59.

[2246] Ex. 84 (DRA-16), p. 60 footnote 132 citing response to DRA-PG&E-108, Question 4 Attachment 8.

[2247] Ex. 38 (PG&E-9), p. 7-3.

[2248] Ex. 38 (PG&E-9), p. 7-4.

9.7.2.1 Administrative & General Salaries

The President's Office is forecasting $4.037 million in labor for test year 2014.[2249] This is a 35% increase from 2011 adjusted recorded costs of $3.689 million. DRA recommends that $1.188 million be removed from the PG&E's President's Office test year 2014 forecast.

The President's Office 2012 recorded costs were $2.924 million which is 17% lower than PG&E's 2012 forecast of $3.683 million. Since PG&E's 2012 costs were over-estimated, DRA recommends the Commission use a three-year average, 2010-2012, to calculate the test year 2014 forecast. A three-year average results in a test year 2014 forecast of $2.849 million.

9.7.2.2 Outside Services -- Utility

The President's Office is forecasting $369,589 in outsides services for the test year 2014.[2250] This is a 41.15%t increase from 2011 adjusted recorded costs of $261,846. DRA recommends that $19,806 be removed from the President's Office Outside Services forecast for test year 2014.

The President's Office 2012 recorded costs were $190,687, or 61% lower than PG&E's 2012 forecast of $494,042. Given the fact that there have been wide fluctuations in outsides services during the record period 2007-2012, DRA recommends using a three-year average to forecast outside services for the test year 2014. DRA has calculated a three year average of $349,783.

9.7.3 Directors Fees and Expenses

PG&E's Board of Directors currently consists of 13 directors and PG&E Corporations Board of Directors currently consists of 12 directors. Of the 13 directors of PG&E, 11 are outside directors and two are officers (PG&E President and PG&E Corporation Chairman, CEO and President). Each outside director receives quarterly retainers for service on the Board as well as fees for attendance at Board meetings, Board committee meetings, and shareholder meetings. In addition, outside directors are reimbursed for reasonable expenses incurred for participating in Board meetings, Board committee meetings, shareholders meetings, and other

[2249] Ex. 39 (PG&E-9, workpapers), p. WP 7-25.

[2250] Ex. 84 (DRA-16), p. 63.

activities undertaken on behalf of PG&E or PG&E Corporation.[2251] PG&E is forecasting Directors Fees and Expenses of $1.617 million, a 3% increase from 2011 adjusted recorded costs of $1.566 million. DRA recommends a forecast of $1,292,583 for Directors Fees and Expenses in test year 2014.

DRA reviewed the 2007 through 2011 directors' fees and expenses[2252] and removed $42,821 of excessive tips, transportation costs, Board general lodging, Board dinner expenses, outside speaker, director education, and candidate interviews costs. After removing those unreasonable expenses from 2007 through 2011, DRA calculated a three- year average for reimbursable expenses. DRA's forecast is a 10% increase in reimbursable expenses for test year 2014, or 140,999.[2253]

PG&E is forecasting Directors quarterly retainers of $15,125 for the test year, which totals to $876,000 for 12 directors. DRA recommends $216,000[2254] less in quarterly retainers than PG&E for test year 2014. Quarterly retainers were $12,500 in 2007 and 2008. PG&E increased the quarterly retainers to $13,750 in 2009. PG&E is forecasting quarterly retainers of $15,125, for test year 2014. PG&E has not justified another 10% increase in Directors' quarterly retainers and DRA recommends that ratepayer funding of the quarterly retainers continue at $13,750. This includes the embedded increase of 10% in 2007 and 2009, and results in test year 2014 forecast of $660,000.

9.8 Corporate Affairs – Communications Department Costs

PG&E is forecasting $19.0 million in Test Year 2014 expenses for its Corporate Affairs - Relations Department.[2255] DRA recommends $18.956 million in the Test Year expenses.[2256] For capital expenditures in the Test Year, PG&E seeks $750 million; DRA recommends zero

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[2251] Ex. 38 (PG&R-9), p. 7-10.

[2252] Ex. 84 (DRA-16), p. 63, footnote 140, citing response to DRA-PG&E-005, Question 39 Attachment 1.

[2253] Ex. 84 (DRA-16), p. 63.

[2254] PG&E's forecast of $726,000 minus DRA's forecast of $660,000 which equals $66,000 adjustment.

[2255] Ex.38 (PG&E-9), p. 8-2.

[2256] Ex. 85 (DRA-17), p. 50, Table 17-20.

ratepayer funding.[2257] The area in dispute is PG&E's proposed Employee Digital Channel Optimization project.

PG&E says the Employee Digital Channel Optimization project will provide social media tools and video kiosks, which will enable employees across the Company to share best practices, provide instant updates on issues affecting work, and provide field employees with timely information.[2258]

For this project, PG&E forecasts $250,000 for expense in 2014 and $750,000 for capital in 2014 and 2015.[2259] PG&E developed the cost forecast using the Company's application development concept estimating tool.[2260] The IT expense costs are forecasted in MWC JV (Maintain IT Applications and Infrastructure) that includes costs for ongoing maintenance, operations and repair for PG&E's applications, systems and infrastructure.[2261] The IT capital costs are forecasted in MWC 2F (Build IT Applications and Infrastructure) that includes the costs to design, develop and enhance applications, systems and infrastructure technology solutions.[2262]

As DRA noted in its testimony, the information discussed above was the only information that PG&E provided about this project. PG&E provided no breakdown of the costs associated with this project anywhere in its testimony or workpapers aside from WP 8-51 to 8-54 which only shows forecast summaries. PG&E did not quantify any ratepayer cost savings associated with this project, nor did PG&E conduct any cost benefit analysis studies.

In Rebuttal, PG&E says that in its workpapers, PG&E "…provided a detailed summary of this project" and that "[t]he project summary includes extensive information about the nature of the project."[2263] The four pages of workpapers PG&E refers to provide no verifiable information and little beyond broad generalizations like, "Social medial tools can help field

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[2257] Ex. 85 (DRA-17), p. 50, Table 17-21.

[2258] Ex. 38 (PG&E-9), p. 8-13.

[2259] Ex. 38 (PG&E-9), p. 8-13 and Ex. 39 (PG&E-9 workpapers), p. WP. 8-48.

[2260] Ex. 38 (PG&E-9), p. 8-13.

[2261] Ex. 38 (PG&E-9), p. 8-13.

[2262] Ex. 38 (PG&E-9), p. 8-13

[2263] Ex. 63 (PG&E-24), p. 7-3.

employees solve problems…[2264]" or "…continued proliferation of broadband capabilities, today's mobile devices and social media channels are creating new opportunities to encourage collaboration…"[2265]

DRA continues to recommend no ratepayer funding for this project.

9.9 Corporate Affairs – External Department Costs

DRA does not oppose PG&E's forecasts in this area.[2266]

9.10 Unbundled Cost Categories (UCC) and Allocation Issues

DRA has no comment on this issue at this time.

10 RESULTS OF OPERATIONS

10.1. Taxes

Regulated tax expense includes the following: (1) Federal Income Taxes (FIT) and State Income Taxes (California Corporate Franchise Taxes (CCFT); (2) payroll taxes; and (3) property, or *ad valorem*, taxes. These tax expense categories are the composite of projected taxable income streams, book expenses, special tax deductions, and tax credits, calculated within the combined contexts of "real world" tax law and "regulatory world" tax law.[2267]

DRA's forecasted tax expenses are computed in the Results of Operations (RO) model, since they are dependent on DRA's forecasts of income, expenses and plant balances.[2268]

The areas where DRA disagrees with PG&E's forecasts have to do with PG&E's Meals and Entertainment adjustments, and Bonus Depreciation. These are discussed below.

10.1.1 Meals and Entertainment Deduction

Federal law places a limit of 50% on the deduction for meals and entertainment expenditures. To incorporate this statutory limit in its revenue requirement, PG&E includes a

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[2264] Ex. 41 (PG&E-9 workpapers), p. WP 8-51.

[2265] Ex. 41 (PG&E-9 workpapers), p. WP 8-52.

[2266] Ex. 85 (DRA-17), p. 54.

[2267] Ex. 88 (DRA-21), p. 1.

[2268] Ex. 88 (DRA-21), p. 1.

negative adjustment equal to 50% of its estimates of the total amount of expense for meals and entertainment.[2269]

DRA does not agree with PG&E's deductions and associated TY 2014 revenue requirement for travel, meals, or ticket expenses, and has removed them from all revenue requirements. These are social activities of dubious benefit to ratepayers.[2270]

DRA's proposed adjustments are supported by previous Commission decisions which have rejected ratepayer funding of expenses for Disneyland tickets, luncheons, and retiree dinners as an unfair economic burden on ratepayers.[2271] Entertainment expenditures also give the appearance of a "free lunch" at ratepayer expense. PG&E's entertainment expenses clearly fall within the category of expenses the Commission has rejected in the past, and DRA recommends the Commission remove them here too.

DRA recommends that the meals-related expenditures be decreased by $356,321 in the appropriate FERC accounts for revenue requirement, and that the associated income tax deductions be reduced by $179,661 (half of the $359,231).[2272]

10.1.2 Bonus Depreciation

A 50% bonus depreciation provision became effective on 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, 2012, the bonus depreciation provision 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.[2273]

[2269] Ex. 88 (DRA-21), p. 10.

[2270] Ex. 88 (DRA-20), p. 10.

[2271] D.82-12-054 (10 CPUC 2d at 140-141); D. 93-12-043 (52 CPUC 2d at 513-514); D.90-01-016 (35 CPUC 2d 80, 135-136); D. 12-11-051, mimeo, pp. 620-621..

[2272] Ex. 88, (DRA-20), p. 11.

[2273] Ex. 88 (DRA-20), p. 12.

PG&E included only 12.5% for bonus depreciation in 2013. DRA recommends that the rate for 2013 should be 50% because the tax law was changed to allow for 50% bonus depreciation for the entire year of 2013.[2274]

DRA also recommends that the 50% bonus depreciation be included for 2014, 2015 and 2016.[2275] At a minimum, the 2014 rate for bonus depreciation should be 12.5% to allow for certain qualifying property placed in service after December 31, 2012 and before January 1, 2014.[2276] Then, if the bonus depreciation rule is extended beyond 2013, PG&E should be directed to update the bonus depreciation rate to 50%, or whatever rate the government sets. [2277]

10.2 Depreciation

PG&E forecasts 2014 plant depreciation expense at $464 million for Gas Distribution (GD) related depreciation expense, $1.351.3 million for Electric Distribution (ED) depreciation expense, and $452 million for Electric Generation related depreciation expense[2278]. This request is 52 percent higher than 2011 recorded depreciation expense, when GD-related depreciation expense was $181.5, ED-related depreciation expense was $531 million and EG-related depreciation expense was $107.1 million.[2279]

DRA recommends $1,064.890 million for ED related depreciation expense, $375.552 million for GD related depreciation expense, and $411.490 million for EG related depreciation expense.[2280] DRA also recommends that the Commission cap increases in net salvage values at -25% to stem the rate shock that might result from rising plant removal costs.

One reason for the differences in DRA and PG&E's depreciation numbers is that DRA's dispute of the Average Service Lives (ASL) used to calculate certain asset classes and the net salvage values assigned to other asset classes. Specifically, there are 4 ASL asset classes and 13 Net Salvage Values asset classes that DRA disputes in this proceeding. Compared to the

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[2274] Ex. 88 (DRA-20), p. 12.

[2275] Ex. 88 (DRA-20), p. 12.

[2276] Ex. 88 (DRA-20, p. 12.

[2277] Ex. 88 (DRA-20), p. 12.

[2278] Ex. 4 (PG&E-2), p. 10-1.

[2279] Ex. 4 (PG&E-2), p. 10-3.

[2280] Ex. 87 (DRA-19), pp. 2-3.

number of asset classes in the depreciation study, DRA's dispute is a relatively modest disagreement the Commission should grant.

PG&E also requests that the Commission adopt weighted average depreciation reserves as follows: $4,867.6 million for GD-related weighted average depreciation reserve, $10,971.1 million for ED-related weighted average depreciation reserve and $8,246.3 million for EG-related depreciation reserve. DRA's recommendations for weighted average depreciation reserves are $10,878.618 million for ED, $4,868.340 million for GD and $8,250.681million for EG.

Depreciation expense in rates is the recovery of the original cost of fixed capital less estimated net salvage over the useful life of the property[2281]. A generally accepted definition of depreciation is the FERC definition in 18 Code of Federal Regulation (CFR), Part 101:

> "Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, and action of the element, inadequacy, obsolescence, changes in the art, changes in demand and requirements of the public authorities."[2282]

Through depreciation, users of plant repay the investment made in putting the plant in service.

> The purpose of depreciation expense is to distribute the original cost of tangible capital assets (less net salvage) used in providing service, in a systematic rational manner, over the useful life of the assets.[2283]

This rational distribution of plant cost over the useful life of the assets is important for intergenerational equity, because plant life may span the lives of several generations of ratepayers and in order for all who benefit from the plant to contribute as equally as possible to

[2281] Ex. 4 (PG&E-2), p. 10-7.

[2282] Ex. 87 (DRA-19), p. 3.

[2283] Ex. 2 (PG&E-4), p. 10-7.

the cost of the investment in the plant, there has to be a systematic and equitable distribution of the plant investment cost over the life of the plant.

Depreciation achieves this purpose by ensuring that the parameters used to determine depreciation expense are properly defined. These parameters include, average service life of the plant, curve type and net salvage rates. The parameters are developed in a depreciation study[2284].

> If the estimated service lives are inaccurate, either too long or too short, an incorrect amount either too long or too short an incorrect amount is charged to expense each year, If the estimate of net salvage at the end of the estimated service life is inaccurate, then the amount charged to expense each year is also incorrect. This could result in customers paying more or less than their fair share compared to future customers.[2285]

One effect of a depreciation study that inaccurately calculates a service life is an escalating depreciation expense that may result in a rate shock when put in rates. This could also occur when plants are put in service far faster than retirements occur or plant removal costs rise to reduce the net salvage value of the retired plants. The parameters used in depreciation contemplate that as plant additions or other factors add to the depreciation expense included in rates, retirements remove old expense charges from rates and net salvage amounts reduce the cost of ongoing depreciation.

Unfortunately, PG&E's depreciation study shows removal costs that are rising at alarming rates and reducing net salvage values, while the same accounts for other California Utilities remain unchanged or are decreasing. In Southern California Edison's (SCE) 2009 rate case, the Commission noted:

> SCE either made no change to its current NSR or proposed to reduce the negative salvage value for Accounts 352, 357, 358, 359, 366, and 370, as well as for General Plant accounts (390-398). No party disputed SCE's proposed NSR for these accounts. Based upon a review of the record, the Commission finds SCE's proposals for the identified accounts to be reasonable and adopts them.[2286]

[2284] Ex. 4 (PG&E-2), p. 10-10.

[2285] Ex. 4 (PG&E-2), pp. 10-7 to 10-8.

[2286] D.12-11-051, p. 675.

In Southern California Edison's (SCE) 2009 rate case, the Commission agreed with DRA's request to freeze net salvage values in order to "mitigate the rate impact of this decision."[2287]

(Ex. 87, DRA-19, p.7.)

DRA requests that the Commission adopt a mitigation measure in this PG&E TY GRC[2288] to bring PG&E in line with other California electric utilities.

While DRA does not contest the bulk of PG&E's recommended depreciation parameters herein, it should be noted that PG&E's depreciation study shows a disconcerting trend toward sharply escalating removal costs, a trend not reflected in the GRC filings of the other major Investor-Owned Utilities (IOUs). Largely due to the severity of these increases, the depreciation parameters requested by PG&E would contribute significantly to a sudden and considerable rate impact. As such, DRA is recommending a cap of 25% to any increases in negative net salvage for this GRC cycle. This will help to mitigate the shock to rates that would result from the adoption of the depreciation parameters requested by PG&E. …

> In Southern California Edison's (SCE) 2009 rate case, the Commission agreed with DRA's request to freeze net salvage values in order to "mitigate the rate impact of this decision."[2289] … The Commission described the freeze to SCE's net salvage rates as "a deferral of the recovery of future net salvage costs."[2290] …

There is no dispute on the fact that PG&E collects far more in accruals than it incurs costs for removals annually. Table 19-7 from DRA's Report is illustrative.[2291]

[2287] Id.

[2288] Ex. 87 (DRA-19), p.7.

[2289] Id.

[2290] Ex. 87 (DRA-19), p. 7; D.09-03-025 at 354, FoF 238.

[2291] Ex. 87 (DRA-19), p.8.

Table 19-7
Total Annual Accrual of Net Salvage and Total Annual Spending on Cost of Removal for Years 2003-2011

Year	Accrual	Spending	Accrual - Spending
2003	$265,492,202	$95,592,129	$169,900,073
2004	$258,337,419	$89,432,939	$168,904,480
2005	$266,489,845	$97,524,517	$168,965,328
2006	$310,281,984	$109,338,517	$200,943,467
2007	$348,731,157	$113,188,545	$235,542,612
2008	$366,755,405	$194,069,780	$172,685,625
2009	$386,699,492	$195,590,050	$191,109,442
2010	$402,769,660	$153,878,447	$248,891,213
2011	$393,835,244	$162,372,897	$231,462,347
Total	$2,999,392,408	$1,210,987,821	$1,788,404,587
Mean	$333,265,823	$134,554,202	$198,711,621

The average over-collection (net accrual) for years 2003-2011[2292] was $198,711,621. PG&E's average spending for removal costs during the same timeframe was $134,554,202. During the nine year period for which PG&E provided complete records, only two years show an over-collection that was less than actual spending. In other words, in seven years out of nine PG&E accrued more than twice the amount for removals than it actually spent on removals. PG&E's current accruals are more than enough to cover removal costs for the time being, even with current net salvage rates. Implementing DRA's recommendation to cap and otherwise limit increases to net salvage will not impact PG&E's ability to fund removals. In light of this, it is reasonable to limit increases in net salvage rates in order to mitigate the impact of such increases on customer rates.

Specific discussion of DRA's recommended changes to PG&E's depreciation parameters follows, broken down by parameter and asset class.[2293]

DRA's proposal is a modest mitigation measure and should be adopted.

[2292] This period was chosen due to the availability of recorded net salvage accrual and removal spending from PG&E, as outlined in PG&E's response to data request DRA_220-01.

[2293] Ex. 87 (DRA-19), pp. 8-9.

AVERAGE SERVICE LIFE

PG&E conducted a depreciation study for this TY 2014 GRC and for the most part, DRA takes no issue with the average service lives (ASL) in PG&E's depreciation study in this proceeding. However, DRA disputes the ASL for the following asset classes: (1) EHP33300 and EHH33300 - Waterwheels, Turbines and Generators; (2) EHP33500 and EHH33500 - Miscellaneous Power Plant Equipment. PG&E acknowledged that these two ASL accounts, which DRA found pursuant to discovery, were mistakes in the study and agreed to correct them.

PG&E requested in initial testimony to decrease ASL on accounts EHP33300 and EHH33300 from 70 to 50 years. In response to DRA discovery requesting the reason for the decrease in ASL, PG&E responded that the requested decrease was due to a mistake in the depreciation study.[2294] PG&E corrected the mistake and provided new depreciation parameters for the requested accounts to DRA. These corrected parameters were included in PG&E's errata. PG&E's corrected proposal requests that ASL on this account remain 70 years. DRA recommends that the Commission adopt 70-year ASLs for accounts EHP33300 and EHH33300.

PG&E initially requested in testimony that the ASL for accounts EHP33500 and EHH33500 remain at the previous 40 years. As with EHP33300 and EHH33300, PG&E identified a mistake in the depreciation study in response to DRA discovery, and provided DRA with an updated ALS of 42 years.[2295] The corrected parameters were included in PG&E's errata. DRA recommends that the Commission adopt a 42-year ASL for accounts EHP33500 and EHH33500.[2296]

NET SALVAGE VALUES

DRA questions the following net salvage values that resulted in the largest increase to PG&E cost of removal. These costs are out of proportions with every other utility that DRA compared them in its analysis.

DRA's recommended changes to net salvage rates are outlined in Table 19-5 and 19-6 of DRA's Report and a comparison of the previous and proposed/adopted net salvage values in the

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[2294] DRA_089-04.

[2295] Ibid.

[2296] Ex. 87 (DRA-19), p. 9.

most recent GRC cycle for each of California's three major IOUs is included in DRA's Report as Tables 19-8 and 19-9.

Station Equipment – ETP35301

As of 2011, the current authorized net salvage rate on this account was -30%. PG&E doubles that rate in this TY 2013 rate case to -60%, a far higher rate of negative net salvage on this account than the other California major IOUs. SCE has a rate of -5%, while San Diego Gas & Electric (SDG&E) has a rate of -10%. Further, the data provided in PG&E's depreciation study to support such a rate, shows a strong inconsistency with removal costs at the other major IOUs. PG&E does not fully explain the drivers of these increasing costs in the depreciation study.

Therefore, DRA recommends a net salvage value of -55% for this account, consistent with DRA's recommendation that increases to negative net salvage be capped at 25%.

Towers and Fixtures – ETP35400

The current authorized net salvage rate on this account from TY 2011 is -60%. PG&E requests a rate of -110%. PG&E's only explanation for this escalation is that "there is a general increase in cost of removal"[2297] , but PG&E does not provide any documentation to support the assertion with particular reference to this account. The -110% rate is also much higher than the net salvage rates collected by the other major California IOUs on the same account. SCE's rate on this account has not changed through two GRC and prior to that SCE's rates were all frozen and SCE collects a rate of -70% on this account. SDG&E collects a rate of -75% for this account and did not request to change in its test year 2012 rate case.

PG&E has not provided sufficient information support this increase. Therefore, DRA recommends that the net salvage rate on this account be -75% in this GRC, in line with the net salvage values maintained by the other major IOUs in their most recent rate case cycles.

Towers & Fixtures (Combined Cycle) – ETP35401

PG&E's current authorized net salvage rate for this account is already high at -60%, but PG&E is requesting a rate of -110%. This account shares a FERC account with ETP35400 (Towers and Fixtures) above and the analysis above applies equally to this account. Thus, DRA

[2297] Ex. PG&E-2, WP p. 11-380.

recommends that net salvage on this account be increased to -75%, consistent with DRA's recommendation for asset class ETP35400.

Poles Towers and Fixtures – EDP36400

The current authorized net salvage rate for this account is -80%. PG&E requests an increase on this account to -150%. As of December 31, 2011 Total Plant in Service in this account was $2,797,336,000. PG&E has requested to increase the total depreciation accrual rate on this account from 4.7% to 6.47%.

Consistent with DRA's recommendation that increases to negative net salvage be capped at 25%, DRA recommends that net salvage on this account be increased to -105%:

The data provided by PG&E in the depreciation study for this account shows two outlier years not representative of the general trend in cost of removal data. In 2008, PG&E recorded a cost of removal that was 944% of regular retirements. For 2009 the cost of removal was 1200%. Cost of removal in these two years was exceptionally high, and as such these outlier years should be excluded from analysis of this account. DRA removed these 2 years from its analysis, and found that considering the years 1990-2007 results in a net salvage rate of -122%.[2298] While this figure is lower than that requested by PG&E, the significant increase in the accrual rate on this account and large amount of plant in service will still result in a substantial increase that would be unduly burdensome to ratepayers.

(Ex. 87, DRA-19, p.11.)

In its last rate case SDG&E requested a 5% reduction in negative net salvage for this account, from -100% to -95%.

Overhead Conductors and Devices – EDP36500

PG&E has proposed close to a threefold increase of the net salvage rate on this account over current rate, from -77% to -200%. Total plant in service in this account as of December 31, 2011 was $3,380,645,000. PG&E requested to increase the accrual rate on this account from 4.64% to 8.2%, nearly double the depreciation accrual rate. This is a significant increase on a large amount of plant should be subject to substantial justification, but PG&E has not produced such justification.

[2298] See Attachment A for the detailed analysis of EDP36400.

PG&E's explanation that "cost of removal is extremely high and is continually increasing [on this account]"[2299] is not supported. These costs are out of line with the cost of removal for this account reported by the other major IOUs. SDG&E proposed a significant decrease in negative net salvage collected on this account from -100% to -70% in its current GRC, and SCE proposed and received a slight increase from -100% to -110%.

> In 2008 PG&E reported that cost of removal was 1012% of the value of regular retirements; in 2009 the reported rate was 1406%. These reported costs are an order of magnitude higher than those reported by the other electric IOUs.[2300]

In light of PG&E's inability to explain the sharply escalating removal costs reported in the depreciation study, DRA proposes a net salvage value of -90% for this account.

Underground Conduit – EDP36600; Line Transformers Overhead – EDP36801; Services – Overhead – EDP36901; Meters & Smart Meters – EDP37000 & EDP37001; Street Lighting and Signal Systems – Lamps and Equipment – EDP37303; Services – Gas – GDP38000; Meters – Gas – GDP38100

The foregoing discussion and analysis reflects a consistent pattern throughout all of the net salvage rates that DRA analyzed in its Depreciation Report. They were consistently high and unsupported by evidence:

Underground Conduit – EDP36600

The current authorized net salvage rate is on this account is -20%, while PG&E is requesting a fivefold increase to -100%. Total plant in service in this account as of December 31, 2011 was $2,261,437,000. PG&E has requested to nearly double the accrual rate on this account from 2.42% to 4.46%.

PG&E states in its depreciation study that analysis for the years 1990-2009 "indicated no salvage but very high constant cost of removal."[2301] In PG&E's depreciation study, the average net salvage rate for years 1990-2009 is -102%. Removal costs for this account have remained constant despite the fact that regular retirements have dropped sharply in recent years. Between

[2299] Ex. 18 (PG&E-2), p. WP 11-484.

[2300] Ex. 87 (DRA-19), p. 12.

[2301] Ex. 18 (PG&E-2), p. WP 11-494.

1990 and 2009, regular retirements averaged $1,103,010, while in the period between 2004-2009, regular retirements averaged $458,731. Asked to explain the escalation in cost of removal, PG&E responded removal that costs had "remained fairly constant."[2302] While this is true, cost of removal relative to regular retirements has shown a sharp increase, one PG&E did not explain in discovery or in the depreciation report.

The other major IOUs have not shown similar trends towards increasing removal costs. SCE did not request an increase in net salvage for this account in its 2012 GRC, and SCE's net salvage rate remains at -20%, the same as PG&E's current rate. SDG&E's current net salvage rate is -40% for this account.

Consistent with DRA's recommendation that increases to negative net salvage be capped at 25%, DRA recommends that net salvage on this account be increased to -45%. This value is slightly higher than SDG&E's rate, and more than twice SCE's. A rate of -45% would more than double the current rate and leave PG&E collecting the highest amount for net salvage on this account of the three major IOUs.

Line Transformers Overhead – EDP36801

The current authorized net salvage rate on this account is -6%, and PG&E is requesting a rate of -25%. The data provided in the deprecation study do not justify this increase. Average net salvage between 1990 and 2009 is -11%; however 2009 is an unusually high year, with a cost of removal of $12,776,345. In contrast, average cost of removal excluding this year is $2,022,298. Excluding the year 2009 from the analysis results in an average net salvage value of -7%.[2303] This is quite close to the current value of -6%.

DRA recommends keeping the current net salvage value of -6% for this account, which is consistent with the historical net salvage rates shown in PG&E's depreciation study.

Services – Overhead – EDP36901

The current authorized net salvage rate on this account is -75%, PG&E is requesting an increase to -135%. PG&E justifies the requested increase in the depreciation study by pointing

[2302] DRA-030-04.

[2303] See Attachment A for the detailed analysis of EDP36801.

out that cost of removal is increasing, and the depreciation study data supports this.[2304] However PG&E does not give further elaboration to justify the increase. As PG&E points out in the depreciation study, overall average net salvage is -56%. PG&E explains the requested -135% rate by pointing out that the five year average for net salvage between the years 2005 and 2009 was -177%.

In its current 2012 rate case, SDG&E has requested a substantial reduction of the net salvage rate on this account from -125% to -90%. In SCE's 2012 rate case, the utility received a slight increase, from -75% to -85%. DRA recommends a net salvage rate of -85%. This is consistent with the other major IOUs, and is a substantially higher rate than the average net salvage value of -56% shown in the depreciation study.

Meters & Smart Meters – EDP37000 & EDP37001

The current authorized net salvage rate for EDP37000 (legacy meters) is -15%, and for EDP37001 (smart meters) is -5%. PG&E is requesting a single rate of -20% for both accounts. Total plant in service in this account is a combination of legacy meters and smart meters, and amounts to $916,875,000 as of December 31, 2011. PG&E has requested to increase the accrual rate on both accounts from 3.96% and 3.27%, respectively, to 6.36%.

The data provided in PG&E's depreciation study is for the entire FERC account, and is not divided into individual asset classes. The average net salvage value for combined meters/smart meters is -10% including data for years 2010-11 which PG&E provided in response to a DRA deficiency notice.[2305]. PG&E claims in its depreciation study that these historical values are not accurately representative of the net salvage value of the new smart meters as they differ in cost of removal and in salvage value, and as the historical plant consists largely of legacy meters.[2306] The depreciation study identifies 2008 as the start of smart meter deployment; data from this year and later should align more closely with the actual salvage value of the new meters. DRA calculated a net salvage value for only these years using the 2008-9 data in the depreciation study and data for years 2010-11 which PG&E provided in response to DRA's deficiency notice. For years 2008-2011 DRA found that the average net salvage value was -8%.

[2304] Ex. 7 (PG&E-2), p. WP11 11-533.

[2305] Deficiency DEF-022-MK3.

[2306] Ex.7 (PG&E-2), p. WP11 11-552.

This is quite close to the current -5% rate, as well as the rates used by the other major IOUs. In SCE's 2012 GRC, the utility requested and received a decrease in net salvage for this account from -10% to -5%. SDG&E requested in its current 2012 GRC to maintain its previous rate of 0%.

DRA recommends that net salvage on this account remain at -5%. As shown in DRA analysis[2307] a rate of -5% is quite close to both the -10% historical average net salvage and the -8% average net salvage since the start of smart meter deployment in 2008. This rate is comparable to the rates at the other major IOUs. If PG&E can substantiate a more appropriate rate with historical data in a future GRC filing, the issue of an appropriate net salvage rate for the new smart meters can be revisited. At this time the available data supports the rate remaining at -5%.

Street Lighting and Signal Systems – Lamps and Equipment – EDP37303

The current authorized net salvage rate on this account is -5%. PG&E is requesting an increase to -65%. PG&E has requested to increase the accrual rate on this account from 1.9% to 6.36%. PG&E explains the requested increase by stating in its depreciation study that the five year average net salvage value for the years 2005-2009 was -68%.[2308]

The sharp increase proposed by PG&E is not however justified by the whole of the data available in the depreciation study. Using the data from the entire period of years 1990 to 2009 provided by PG&E, DRA determined that the average net salvage amounts to roughly -10%. This average excludes 1996, an outlier year in which PG&E recorded an unusually large amount of positive salvage value.[2309] Including 1996, DRA found that the average the net salvage rate is positive, at 5%.

DRA recommends that net salvage on this account be increased to -10%, as this is the average net salvage rate shown in the depreciation study from 1990-2009 excluding the outlier year of 1996.

[2307] See Attachment A for the detailed analysis of EDP37000 and EDP37001.

[2308] Ex. 7 (PG&E-2), p. WP 11-597.

[2309] See Attachment A for the detailed analysis of EDP37303.

Services – Gas – GDP38000

The current authorized net salvage rate for this account is -105%; PG&E are requesting an increase to -180%. Total plant in service in this account as of December 31, 2011 was $2,625,154,000. PG&E has requested to increase the accrual rate on this account from 3.36% to 5.36%.

According to the data in the depreciation study, cost of removal amounts for this account have been high in recent years relative to retirements. The study does not explain the high costs of removal, saying only that "cost of removal is very high and continues in recent years to get even higher."[2310] In response to DRA discovery, PG&E responded that such increases "particularly in years 2005-2009, [are] due primarily to PG&E's copper services replacement project (CSRP) and gas pipeline replacement project (GPRP)."[2311]

In addition, it is reasonable to limit increases to the net salvage rate on this account given the increased pace of the GPRP during this GRC cycle, as the program will have a strong impact on future cost of removal levels. The impacts of the GPRP on negative net salvage rates can be reevaluated in the next GRC when data is available on how the program is affecting costs.

This is a large account and PG&E's requested increase is significant. As such, DRA recommends that the net salvage rate on this account be increased to - 130%, consistent with DRA's recommendation that increases to negative net salvage be capped at 25%.

Meters – Gas – GDP38100

The current authorized net salvage rate on this account is -5%, PG&E is requesting an increase to -25%. Average net salvage on this account is -26% given the numbers provided by PG&E in its depreciation study. However the years 2008 and 2009 both show removal costs well outside the norm for the available data, at $7,392,086 and $10,275,918 respectively. The highest cost year previously was 2004, with a total cost of removal of $2,015,285. The average cost of removal excluding these outlier years was $285,796. DRA excluded these years from the analysis, and the result was an average net salvage value of -7%.[2312] This value is much closer

[2310] Ex. 7 (PG&E-2), p. WP 11-701.

[2311] DRA-030-04.

[2312] See Attachment A for the detailed analysis of GDP38100.

than PG&E's requested 25% to the net salvage rates used by the other major IOUs, both of which have a net salvage rate of 0% for this account.

In light of the results of excluding outlier years from the depreciation study and of the net salvage rates collected on this account by the other major IOUs, DRA recommends that net salvage on this account remain at the current value of -5%.

11 RATE BASE, WORKING CASH AND FINANCE ISSUES

11.1 Allowance for Funds Used During Construction

In its most recent GRC decision, the Commission stated that the Allowance for Funds Used During Construction (AFUDC) represents the forecasted financing costs (both debt and equity) that are used to finance utility plant construction, i.e., construction work in progress (CWIP).[2313] The AFUDC generally cannot be recovered until the facility becomes operative. During plant construction, the AFUDC is accumulated in the CWIP. When the facility becomes operative, i.e., used and useful, the AFUDC is then capitalized,[2314] and the utility can then earn a return based on its authorized the rate of return (ROR).

The CWIP is not included in rate base from the date of inception of the project because 1) has not yet been deemed a reasonable expenditure and 2) it is not yet used and useful in providing benefits to the utility ratepayers.[2315] Only after the cost has been determined to be reasonable and the asset is being used and is useful to ratepayers is the utility allowed to add the asset to rate base and to begin earning a return on the asset[2316]

11.1.1 PG&E's Request and DRA's Recommendations

In its Application, PG&E asks that the AFUDC rate to finance CWIP be set using the cost of its "long-term debt and equity financing in compliance with PG&E's CPUC authorized capital structure." DRA recommends an AFUDC rate of 3.91%. DRA's calculation is shown in its testimony, Exhibit 88, in Table 20-1, and is reprinted below.

[2313] D.13-05-010, mimeo, pp. 984-985; 2013 Cal. PUC LEXIS 227,*1431.

[2314] Id.

[2315] Ex. 88 (DRA-20), p.14.

[2316] Id.

DRA's Recommended AFUDC Rate

	Capital	Cost	Weighted Cost
Short Term Debt	30.00%	0.16%	0.05%
Long Term Debt	32.90%	8.79%	1.82%
Preferred Stock	0.70%	5.60%	0.04%
Common Equity	36.40%	8.79%	2.01%
AFUDC Rate	100.00%		3.91%

PG&E's request that CWIP earn the full-authorized ROR from the date that costs are first incurred is virtually the same as requesting that CWIP be included in rate base from the inception of each project[2317] PG&E's methodology is counterintuitive, and contrary to Commission policy for even having the distinction between AFUDC and CWIP. AFUDC recorded during the construction period is capitalized[2318] into rate base for future recovery instead of being recovered in the current year.

The Commission handles AFUDC and CWIP in the manner described above because, prior to completion of construction, the project provides no service or benefit to ratepayers[2319]. It is neither used nor is it useful. As noted in D.11-05-018, plant that is not used and useful is normally excluded from rate base, and "therefore excluded from earning a rate of return."[2320] The Commission has applied the used and useful principle for nearly a decade.[2321]

Thus, for energy utilities there has historically been the presumption that, until the asset is used and useful to the ratepayers, it should not be included in rate base. When it becomes used and useful, it is added to rate base and ratepayers pay for that use by paying a return on the net book value of the asset. After it is no longer used and useful, the asset is removed from rate base

[2317] Ex. 88 (DRA-20), p .15.

[2318] *Id.*

[2319] *Id.*

[2320] D.11-05-018 at 53-54. 2013 Cal. PUC LEXIS 227, p.*1326.

[2321] D.13-05-010; 2013 Cal. PUC LEXIS 227 p.*1325.

so that ratepayers do not continue to pay for something that provides them with no benefit. Likewise, prior to completion of the construction of a particular project, the project provides no service or benefit to ratepayers.[2322]

11.1.2 Justification for AFUDC

When an entity, whether regulated or non-regulated, constructs an asset, there are carrying costs used to finance the construction of that asset[2323] Those carrying costs add to the total cost of construction. In ratemaking for regulated utilities, those carry costs are eferred to as Allowance for Funds Used During Construction. While it is appropriate to recognize AFUDC as part of the cost of construction, the question is what is the appropriate rate.

For a non-regulated entity, AFUDC is a cost that it will seek to keep as low as possible[2324] A non-regulated entity cannot set or increase its future earnings based on the total cost of the asset. Its future revenues related to a constructed asset are determined by competitive market forces rather than on the mechanisms that exist in a regulated environment. A higher AFUDC amount will result in a higher asset cost and a lower return earned on that asset in the future.[2325]

A non-regulated entity will have a clear incentive to 1) keep the AFUDC rate as low as possible which will keep the final asset cost as low as possible, 2) keep the construction period as short as reasonably possible. A well-run non-regulated entity will actively seek to keep its AFUDC rate as low as possible by utilizing short-term debt and long-term debt to the maximum extent possible.

In contrast, a regulated utility, such as PG&E, does not have the same motivation to minimize AFUDC costs because a higher AFUDC will result in a higher rate of return.[2326] Thus, PG&E's profits increase with a higher AFUDC. The costs for AFUDC included in the asset eventually are included in rate base, which is the basis for a regulated utility's earnings. So

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[2322] Ex. 88 (DRA-20), p.15.

[2323] *Id.*

[2324] *Id.*

[2325] Ex. 108.

[2326] Ex. 108, at 16.

there is definite motivation for PG&E to make the AFUDC rate as high as possible in order to maximize its earnings.

Due to the monopoly nature of PG&E, the Commission must provide a reasonable restraint on costs as a substitute for market forces that do not exist in a monopoly setting. Allowing a utility to use its full ROR as the rate for its AFUDC is bad policy, since it gives the utility little incentive to control costs. It also removes an incentive to minimize the time to complete construction projects.

The Commission should provide a reasonable framework as a proxy for a competitive marketplace from which a utility's management can make decisions. Regulatory policy thus provides restraints that can lead to more efficient and ratepayer friendly decisions by the utility.[2327]

The Federal Energy Regulatory Commission's (FERC) formula for AFUDC includes short-term debt along with the components of a utilities capital structure used to determine its ROR, which includes long-term debt, preferred stock and common stock. Utility management has discretion over how much of each component is used.

PG&E has included zero short-term debt in its requested AFUDC rate. This has the effect of maximizing the possible AFUDC rate. It also has the effect of treating CWIP the same as other rate base items that are used and useful in providing service to ratepayers. So even if PG&E uses short-term debt to finance CWIP, the rate PG&E would record for AFUDC is its full authorized ROR.

11.1.3 Short-Term Debt in AFUDC Rate Calculation

PG&E says that it currently "has a revolving line of credit of $3 billion."[2328] Information PG&E included in its GRC Application shows that its short-term borrowings were $1.647 billion at December 31, 2011 and $0.397 billion at September 30, 2012.[2329] PG&E's application also shows CWIP as $1.770 billion at December 31, 2011, and $2.095 billion at September 30, 2012.

[2327] Ex. 88 (DRA-20), p. 16.

[2328] Ex. 42 (PG&E-10), Chapter 11, pp. 11-13, lines 16.

[2329] A.12-11-009.

DRA requested that PG&E provide actual short-term debt amounts by month for the five years 2008 to 2012.[2330] PG&E provided the average funds outstanding by month. The short-term debt amount during that five year period ranged from a low of $0.60 billion to a high of $1.602 billion. The average monthly amount for the five years was $0.775 billion.[2331] Based on these numbers, there is sufficient room and ability for PG&E to use short-term debt to finance a portion of its CWIP. The issue is what is an appropriate amount. In practice, that question is a management decision. But for ratemaking, the Commission must set that rate to provide incentive for PG&E to be efficient in its use of capital and to also provide fair and equitable treatment for ratepayers.

DRA proposes that it is reasonable to use short-term debt to fund 30% of CWIP. That amounts to $0.531 billion at December 31, 2011, and $0.629 billion at September 30, 2012. It is not clear whether any of PG&E's current short-term borrowings can be attributed to CWIP. If it were assumed that the current amount is zero, adding these amounts to the existing short-term debt would result in $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 borrowings for 2008 to 2012 ($0.775 billion), gives a total average short-term debt of $1.404 billion.[2332] Each of these numbers is well below PG&E's current revolving line of credit of $3 billion[2333]. PG&E clearly has room to finance 30% of its CWIP with short-term debt. At times, PG&E has sufficient short-term debt capacity to finance 100% of CWIP. The actual percentage of short-term debt used is a management decision.

Including 30% short-term debt in the calculation of PG&E's CWIP will provide a regulatory restraint on costs that a completive market place does not provide due to PG&E's monopoly status. DRA recommends that the AFUDC rate calculation include short-term debt at 30% of the total capital used to finance CWIP.

[2330] DRA 88 (DRA-20) p. 17.

[2331] *Id.*

[2332] *Id.* at 18.

[2333] *Id.*

The rate for short-term debt would be equal to PG&E's actual average short-term debt rate. As a proxy, DRA uses the 2014 projected rate for 3-month commercial paper, or 0.16 percent.[2334]

11.1.4 Return on Equity in AFUDC Rate Calculation

CWIP is treated differently from rate base, in part because it is not yet providing service to ratepayers. It is not yet used nor is it useful. Providing a full rate of return on an asset that is not yet used and useful does not provide any incentive for PG&E to control its costs similar to the control provided via competitive markets for non-regulated entities.

In D.11-05-018, PG&E's last GRC, the Commission addressed a situation where an asset was not used and useful, but for which the Commission determined that a return was appropriate.[2335] In that decision it was determined that the return on equity should be set at the same rate as the long-term debt rate. In so doing, a return was allowed but it was not equal to that authorized for a used and useful asset that provides benefits to ratepayers.

Using that approach to CWIP, DRA recommends that the return on equity rate for the AFUDC calculation be set at the long-term debt rate. Using PG&E's latest authorized cost of capital, that rate would be 8.79 percent as opposed to the authorized equity rate of 10.4 percent. This rate would change as PG&E's cost of debt rate changes in its authorized cost of capital updates. DRA recommends that the Commission adopt an AFUDC rate of 3.91%.

11.2 Nuclear Fuel

PG&E includes in its ratebase forecast, the weighted average value of Diablo Canyon nuclear fuel inventory in the amount of $399.322 million and $1.533 million for fuel oil inventory for the Humboldt Bay Power Plant.[2336] Fuel inventories including nuclear fuel are evaluated annually in Energy Resource Recovery Account (ERRA) proceedings. Carrying costs refer to the cost of holding or storing fuel inventory. Ratepayers pay for the cost of holding or storing fuel until it is consumed.[2337]

[2334] Ex. 88 (DRA-20), p. 18 citing IHS Global Insight, US Economic Outlook, April, 2013.

[2335] D.11-05-018, Rate of Return on abandoned meters.

[2336] *See* Exhibit 5, PG&E-2 Workpapers, p. WP 14-7 for electric distribution and gas distribution, and p. Exhibit 20, WP 14-8 for electric generation

[2337] Ex. 89 (DRA-21), p. 5.

Consistent with long-standing Commission policy, DRA recommends that the carrying costs for the PG&E fuel inventories continue to be recovered in the ERRA proceedings. DRA, therefore, removes from rate base the entire $399.322 million of Diablo Canyon nuclear inventory, and $1.533 million for fuel oil inventory for the Humboldt Bay Power Plant.

Commission direction on this issue has been clear for decades, yet once again, PG&E seeks to include nuclear fuel inventory in rate base. This request should, once again, be denied.

In D.85-12-107, the Commission first addressed the question of proper rate treatment of fuel inventory for the SCE by stating:

Edison no longer shall be allowed to charge ratepayers the cost of carrying fuel oil in inventory at the authorized rate of return. There are several reasons for this. First, the authorized rate of return includes equity and long-term debt. The cost of using equity rather than debt is higher to the ratepayer because of the income tax that must be recovered with a return on equity. Second, the balancing account associated with the ECAC expense was not designed to reward the company with its rate of return on a non-rate base item but to shield the company from wide swings in fuel expenses. Finally, the low-risk nature of fuel oil inventories call for a different ratemaking approach.[2338]

The Commission concluded:

> Fuel oil inventory is low risk. Unlike rate base assets, fuel oil inventory is subject to balancing account treatment. In effect, Edison (SCE) has been guaranteed recovery of its rate of return on a low-risk asset. This result was never intended to occur through ECAC procedures.

In D.87-12-066,[2339] the Commission extended the above holding, saying:

> Although Edison (SCE) points out that the operating and life cycle characteristics of nuclear fuel are not the same as coal, gas, and oil, we believe that this is not enough to warrant a different ratemaking treatment. In fact, Edison (SCE) proposes to finance nuclear fuel with a combination of short- and intermediate-term debt. While this might indicate that there is a need to factor in the cost of

[2338] D.85-12-107, 20 CPUC 111,112, as modified in D.86-05-095, slip op. at p.2. 1985 Cal. PUC LEXIS 1129 at *2.

[2339] D.87-12-066, 26 CPUC 2d at 392

> intermediate debt in deriving the carrying cost associated with nuclear fuel, it does not justify rate base treatment. (Id.)

In that decision and subsequent ones the Commission found that, because fuel "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."[2340] The Commission further stated that this was the reason why short term debt should be used for nuclear fuel.[2341] The Commission directed SCE to calculate carrying costs on its unspent nuclear fuel and coal reserves using the cost of short-term debt, and continue to include these costs in its former ECAC (now ERRA) balancing account.[2342]

Citing D.85-12-107 as standing for the principle that ratepayer's share of the carrying cost of fuel inventories has been held to be the cost of "short-term debt," the Commission found that SCE's calculation of short-term debt was within the meaning of that term. Thus, the Commission approved the slightly higher yield figure for calculating the forecast and actual carrying costs.

In D.88-09-031,[2343] the Commission authorized SCE to finance nuclear fuel with a blend of short and intermediate-term debt. In that case, DRA argued that one short term interest rate should be used to calculate the carrying costs of all fuel inventories, especially since, at the time SCE, was not actually financing its nuclear fuel with any intermediate-term debt.

The Commission has continuously agreed with DRA, stating, "[w]e sees no difference in the financing of these fuels. SCE and other utilities can use a myriad of borrowing arrangements…including intermediate-term debt …to finance carrying costs."[2344] As noted earlier, the utility is free to finance these inventories however it pleases, but the Commission has decided to limit the ratepayer's share in that expense in the short-term interest rate.[2345]

[2340] D.09-03-025 2009 Cal. PUC LEXIS 165, at LEXIS*438, emphasis added.

[2341] *Id.* at LEXIS *437

[2342] D.87-12-066, 26 CPUC 2d at 392.

[2343] D.88-05-031, 29 CPUC 2d at 314.

[2344] D.93-01-027, 47 CPUC2d at 694.

[2345] Id.

In 1985, the Commission established the Energy Cost Adjustment Clause (ECAC now ERRA) mechanism to provide an industry-wide mechanism to provide public utilities with yearly recovery of fuel costs for electric operation. The Commission determined the most cost effective procedure to pay utilities for fuel costs was in this annual proceeding. All California public utilities are currently subject to this fuel cost recovery mechanism.

DRA recommends that the Commission maintain the current fuel cost recovery mechanism, as articulated in D.96-01-011. In that decision, the Commission denied SCE's proposal to split fuel costs into permanent and temporary portions and disagreed with the permanent inventory level concept, stating the increased risk was "insufficient to justify the change in financing."[2346] The Commission further stated,

> We believe it more efficient to include determinations of the reasonableness of fuel inventory levels in the ECAC proceedings. That proceeding engages fuel experts who review the utility's fuel purchasing policies as a whole taking out one piece of that puzzle.[2347]

In D.06-05-016, the Commission stated "We are not persuaded to change the current ratemaking treatment for fuel inventory. There is a long history to the issue."[2348] The Decision then went on to discuss the consistent treatment of fuel inventory, and concluded that,

> Nothing has changed. The reasons why we rejected rate base treatment for fuel inventory has nothing to do with the reasons why we included customer deposits in the operational cash requirement analysis. Fuel inventory was excluded from rate base because of the cost to ratepayers, the balancing account treatment for fuel expenses and the low risk nature of fuel inventories. Inclusion of customer deposits in the operational cash requirement is not new. Non-interest bearing customer deposits have always been included. SCE however pays interest on customer deposits, so prior to D.04-07-022, its customer deposits were excluded in developing the operational cash requirement. The Commission, in D.04-07-022, instead compensated SCE for the interest it pays on customer deposits and estimated a balance of funds that would be available to offset the operational cash requirement. The result was reduced

[2346] D.96-01-011, *mimeo.*, p.226.

[2347] D.96-01-011, *mimeo.*, p.227.

[2348] D.06-05-016, *mimeo.*, p.271.

> overall costs to ratepayers, while SCE was fully compensated for interest costs it paid.
>
> The Commission's determinations regarding fuel inventory and customer deposits are consistent, in one respect. That is, changes were made to existing practices, which resulted in reduced rates while still providing SCE a fair opportunity to recover its costs. These results are consistent with our responsibilities, in general, and we see no reason to alter the currently adopted ratemaking associated with either issue.[2349]

In D.09-03-025, the Commission again reiterated its policy on financing nuclear fuel inventory:

> The Commission has previously determined that nuclear fuel inventory should not be included in rate base and financed through rate of return on rate base but should instead be financed through short-term debt.[2350]

In SCE's 2012 GRC, Application 10-11-015, SCE did not ask for any carrying costs associated with fuel inventory.

For decades, included the costs of nuclear fuel within each utility's respective ERRA account. PG&E has failed to provide any new evidence in its testimony to modify this long-standing Commission policy on this matter. DRA recommends that the carrying costs associated with fuel inventory continue to be recovered through the ERRA consistent with the current Commission policy and numerous past Commission decisions on the matter.[2351]

11.3 **Customer Deposits**

DRA takes no position on this issue at this time.

[2349] D.06-05-016, *mimeo*., pp.274-275.

[2350] D.09-03-025, *mimeo*., p.361.

[2351] Ex. 89 (DRA-21).

11.4 Other Working Cash Issues

11.4.1 Materials and Supplies – Other

PG&E's proposal on Materials and Supplies (M&S) – Other, is based on forecasted maintenance and construction activities and anticipated changes in commodity costs. D.82-12-045 states that "As long ago as 1923 the Commission clearly stated that an allowance for materials and supplies in inventory should cover only those supplies kept on hand for inventory and not those held for construction work."

DRA performed a detailed review of the historical trends of the recorded data from 2007 to 2012, and a comparison of PG&E's GRC proposals of 2011 and 2014. PG&E's Electric Generation operations are broken down into Hydro Facilities, Fossil Facilities, and Diablo Canyon Nuclear Generation Facilities. The recorded adjusted weighted average yearly-totals for Electric Generation M&S for 2007 to 2011 are $68.5 million, $73.8 million, $80.2 million, $85.2 million, and $92.2 million respectively, and approximately $102 million for 2012. The average increase per year over this period is $6.7 million. PG&E proposes $132.7 million for Electric Generation in the current GRC, which is about a $15 million per year increase from 2012 to 2014.

DRA performed linear regression analyses of the recorded data from 2007 to 2012 for Hydro Facilities, Fossil Facilities, and Diablo Canyon Nuclear Generation Facilities.[2352] Extrapolations from the resulting trend lines of the regression analyses to 2014 give M&S projections for Hydro Facilities of $1.7 million, Fossil Facilities of $16.5 million, and Nuclear Generation Facilities of $95.8 million for a total of $114.0 million. DRA recommends a $114.0 million working capital for Electric Generation M&S, a reduction of $18.7 million form PG&E's proposed $132.7 million.

11.4.2 Prepayments

PG&E presents Prepayments are presented in two sub-categories. Company-wide Prepayments include prepaid software license fees and prepaid insurance. Departmental Prepayments include a recovery charge for the cost of the second refueling outage for Diablo Canyon Nuclear Power Plant.

[2352] Ex. 89 (DRA-21), p. 10.

11.4.2.1 Company-wide Prepayments

PG&E proposes a total of $76.784 million in company-wide prepayments for Electric Distribution, Gas Distribution, and Electric Generation in 2014, while DRA's forecast is $63.893 million.[2353]

Insurance prepayments for PG&E's 2014 GRC are based on the 12-month weighted recorded average unamortized balances adjusted by a percentage of anticipated growth from 2011 to 2014 in Administrative and General (A&G) accounts 924 and 925. The growth factor based on PG&E's anticipated insurance growth to 2014 is 2.063.[2354] Software license fee prepayments are based on the 12-month 2011 recorded average adjusted for inflation with A&G escalation rates.

The difference in these prepayments between DRA and PG&E is due to the difference in A&G expense estimates. DRA projects a slower growth of A&G accounts 924 and 925. DRA recommends certain adjustments to PG&E's anticipated growth in these two A&G accounts.[2355] As the result of these adjustments, the insurance growth factor is lowered to 1.424. Incorporating this growth factor into the prepayment calculation yields total prepayments of $63.893 million for Electric Distribution, Gas Distribution, and Electric Generation.[2356]

11.4.2.2 Company-wide Prepayments

PG&E proposes a total of $76.784 million in company-wide prepayments for Electric Distribution, Gas Distribution, and Electric Generation in 2014. DRA's forecast is $63.893 million.[2357]

The difference between the two forecasts relates to disputes between PG&E and DRA about Administrative and General expenses.[2358] These are discussed in detail in Section 9 of this Opening Brief, above.

[2353] Ex. 89 (DRA-21), p. 13.

[2354] Ex. 11 (PG&E-2-WP), p. WP 13-20.

[2355] These discussions can be Exhibit 84 (DRA-16), Chapter 5

[2356] Ex. 89 (DRA-21), pp. 13-14.

[2357] Ex. 89 (DRA-21), p. 13.

[2358] Ex. 89 (DRAA-21), p. 14.

11.4.2.3 Departmental Prepayments

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 Diablo Canyon Nuclear Power Plant (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.[2359]

PG&E states that it will pay for the total cost of $56.1 million in 2014 for the second refueling outage at DCPP, and requests cost recovery over three years. The yearly recovered amount would be $18.7 million. However, PG&E has also proposed recovery of $18.7 million as an O&M expense in 2014 in the nuclear O&M testimony.[2360] DRA recommends subtracting this O&M expense charge from the $56.1 million before calculating the prepayment amount that should be recovered over the 3-year rate case cycle. Therefore, the prepayment amount should be $12.4 million (one-third of $56.1 million minus $18.7 million) instead of $18.7 million (one third of $56.1 million).

In cross examination of DRA's witness, PG&E's attorney attempted to justify PG&E's recovery of the entire $56.1 million in rate base by asking DRA's witness to confirm that various numbers added up to various totals. None of the numbers had any connection to the numeric values in PG&E's Application; in the end, DRA's witness was asked to confirm that "we're [PG&E] still out of pocket $3."[2361] But this, as one of PG&E's witnesses said, "is just math."

The reality of the situation is much more complex than using $1 to $3 examples. As the DRA witness noted, there were $18.5 million dollars in O&M expenses that did not fall within the example given during hearings.[2362] DRA continues to recommend that the Commission reduce PG&E's proposed total Departmental Prepayments by $6.3 million due to DCPP Second Refueling Outage.

[2359] Ex. 11 (PG&E-2), p. WP 13-21.

[2360] Nuclear O&M discussion appears in Ex. PG&E-6.

[2361] 24 RT 3026-3033, Lee/ DRA.

[2362] *Id.* p. 3029.

11.4.3 Deferred Debits

Deferred Debits are debits that are still in the process of amortization and are not included in other current asset accounts. PG&E forecasted these deferred debits based on the 12-month weighted 2011 recorded average adjusted with the A&G inflation escalation factors.[2363]

The average monthly-recorded deferred debits from 2007 to 2012 shows no obvious trend. DRA proposes to use the annual average to derive an amount for 2014.[2364] The yearly average of these 6 years (2007-2012) is $515,000. DRA recommends this amount for 2014. The DRA recommendation results in a reduction of $2.819 million from PG&E's proposed total of $3.334 million.[2365]

11.4.4 Accrued Vacation Deduction

Accrued vacation is a deduction from a utility's operational cash requirement as defined by the Commission's Standard Practice (SP) U-16. PG&E proposed using the 2011 recorded value and making accounting adjustments of $45.7 million for under-accruals.[2366]

DRA does not agree with PG&E that the $45.7 million accounting adjustments are necessary. There are always variations in expenses that may or may not be captured in rates in various accounting and regulatory categories. In some instances, the utility may spend more than authorized, and in other instances less. It is inappropriate to make an exception with the adjustments in the case of accrued vacation. DRA recommends using the 2012 recorded monthly average for accrued vacation without any accounting adjustments, and allocating this as follows: $93.539 million for Electric Distribution, $50.228 million for Gas Distribution, and $52.790 million for Electric Generation[2367]

[2363] Ex. 4 (PG&E-2), p. 13-6, Lines 17 to 20.

[2364] Ex. 89 (DRA-21).

[2365] Ex. 89 (DRA-21), p. 15.

[2366] Ex. 89(DRA-21), p. 15 citing PG&E response to DRA-PG&E-140-KCL, Q.1.

[2367] Ex. 89 (DRA-21), p. 16, citing DRA-PG&E-241-KCL, Q.2. .

11.4.5 Cash Required Due to Time Lags

PG&E performed lead lag studies to establish revenue and expense lag days for the receipt of revenues and for the payment of numerous different types of expenses.[2368]

DRA reviewed PG&E's proposed average lag days, compared them to the corresponding ones from the 2011 GRC.

DRA recommends adjusting the average lag days for Federal Income Tax (FIT), California State Corporation Franchise Tax (CCFT), Goods and Services, and average lag days for revenue collection.[2369]

Lag days for FIT and CCFT proposed by PG&E were not calculated based on recorded data. They were estimated "Based on 2014 Present Expenses." DRA asked PG&E to calculate the lag days with actual recorded data of years 2007 to 2011 for PG&E, the Utility. PG&E provided the calculated results for CCFT, but stated that PG&E did not make any FIT payments in 2009, 2010, and 2011 because the company reported a net operating loss for taxes.[2370] PG&E indicates that the FIT calculation for 2008 is not meaningful, so no lag days were provided. The CCFT lag days for 2007 is much lower than those for 2008 to 2011, and seems to be an aberration. This is similar for the 2007 lag days for FIT.[2371]

DRA recommends 132.85 days as the expense lag days for CCFT, which is the average based on PG&E calculated lag days for 2008, 2009, 2010, and 2011.[2372] For FIT expense lag days, DRA recommends 110.85 days, which is consistent with PG&E's proposed number in the 2011 GRC[2373] Given that no FIT recorded tax data is available in 2008, 2009, and 2010 to make the calculation, DRA recommends the Commission use the most recently proposed and adopted figure from PG&E's last GRC as a reasonable FIT expense lag.[2374]

[2368] Ex. 4 (PG&E-2), pp. 13-12 13-13, 13-15.

[2369] Ex. 89 (DRA-21), pp. 11-18.

[2370] Ex. 89 (DRA-21), p. 17 citing PG&E response to DRA-PG&E-139-KCL, Q.3.

[2371] Ex. 89 (DRA-21), p.17

[2372] Id.

[2373] Chapter 13, PG&E-2, Page 13-9, Direct Testimony for the 2011 GRC.

[2374] D.11-05-018 (contained within the settlement)

PG&E proposed lag days for Goods and Services of 20.56 days, as compare to its proposed 39.64 days in the 2011 GRC,[2375] and 40.31 days in the 2007 GR.[2376] The 20.56 days is a significant reduction from the two previous GRCs of 39.64 and 40.31 days. DRA asked PG&E to recalculate the lag days based on 2012 recorded data. PG&E responded that it would require an extensive re-calculation and would require relatively costly and time-intensive efforts. The 100% reduction in lag days compared to the two most recent GRCs is supported by 2012 data. DRA recommends using the 2011 GRC adopted lag days of 39.64 as the expense lag days for Goods and Services in the current GRC.[2377]

PG&E proposed revenue lag days of 43.14 days in the current GRC. It proposed revenue lag day of 40.81 days in the 2011 GRC.[2378] With all the money the ratepayers provided PG&E to acquire new computer technology, to make the bill collection system more efficient, to implement SmartMeters, and to improve on other technology systems, the revenue collection lag day 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.[2379]

11.5 Financial Health

DRA has no comment on this issue at this time.

12 POST TEST YEAR RATEMAKING

12.1 Introduction and Summary of Recommendations

In its Application, PG&E seeks Commission authorization for an attrition mechanism which would yield estimated revenue increases totaling $496 million (6.1%) for 2015 and $504 million (5.9%) for 2016. Specifically, PG&E's Application estimates the following revenue increases: for Electric Distribution -- $234 million in 2015, and $246 million in 2016; for Gas

[2375] Ex. 89 (DRA-21), p. 17, citing Chapter 13, PG&E-2, Page 13-9, Direct Testimony for the 2011 GRC.
[2376] Ex. 89 (DRA-21), p. 69, citing DRA Report on GRC TY 2007, Rate Base, April 14, 2006.
[2377] Ex. 89 (DRA-21), p. 18, citing Chapter 13, PG&E-2, Page 13-9, Direct Testimony for the 2011 GRC.
[2378] Ex.89 (DRA-21), p. 18 citing Chapter 13, PG&E-2, Direct Testimony for the 2011 GRC.
[2379] Ex. 89 (DRA-21), p. 18.

Distribution - $187 million in 2015 and $160 million in 2016; and for Electric Generation - $71 million in 2015 and $98 million in 2016.[2380]

DRA recommends post-test year revenue increases of $168 million (2.6%) and $158 million (2.4%) in 2015 and 2016 respectively.[2381]

DRA does not oppose a Post-Test Year Ratemaking mechanism which will provide PG&E with some reasonable level of revenue increases in 2015 and 2016. However, the average annual increases of approximately 6% that PG&E proposes for those two attrition years are excessive.

In contrast, DRA recommends a PTYR mechanism whereby attrition revenue increases for PG&E are set at 2.3% per year for 2015 and 2016, plus additional revenues for forecasted leak repair expenses.[2382] DRA's recommended percentage increases are guided by a recent forecast of the All-Urban Consumer Price Index (CPI-U), as well as the increases adopted by the Commission in PG&E's last two General Rate Cases (GRCs).

If the Commission does not adopt DRA's CPI-based recommendation and instead decides to rely on a mechanism similar to DRA's, then DRA does not oppose PG&E's proposed method for developing 2015 and 2016 net capital additions forecasts. DRA does recommend that such a mechanism use the 50% bonus depreciation rate in the post-test year 2015 and 2016 tax calculations. DRA also recommends that post-test year increases for operational expenses be calculated by escalating 2012 adopted levels by traditional escalation factors except for the following:

- The Commission should adopt wage escalation rates of 1.7% in 2015 and 1.9% in 2016 in contrast to PG&E's proposed wage escalation rates of 2.79% per year for 2015 and 2016.

[2380] Ex. 90 (DRA-22), p. 1.

[2381] Ex. 90 (DRA-22), p. 1. DRA based its calculations on the testimony PG&E provided with its Application. In Errata, both PG&E and DRA have made changes to some estimates which will change the ultimate revenue requirement increase amounts when they are run through the Results of Operations Model.

[2382] Ex. 90 (DRA-22), p. 1, footnote 1: With DRA's forecast of additional revenues for gas leak repairs, PG&E would actually receive effective post-test year revenue increases of 2.6% in 2015 and 2.4% in 2016.

- If the Commission chooses not to adopt DRA's forecasts for post-test year gas leak repair expenses (MWC FI), then DRA recommends that the Commission allow PG&E to file Tier 2 advice letters in the ensuing years, requesting incremental revenues necessary to cover the increased costs above DRA's forecast and up to, but not exceeding, a cost cap.
- The Commission should reject PG&E's proposal to escalate medical programs costs by 8.4% in 2015 and 8.2% in 2016. DRA recommends more reasonable and modest escalation rates of 6.4% in 2015 and 6.3% in 2016 based upon a recent IHS Global Insight forecast.[2383]

PG&E makes other proposals for the Test Year that it seeks to carry over in the post-test years. For example, PG&E proposes a 2-way balancing account for Gas Distribution expenses. DRA has addressed that proposal above in Section 3, Gas Distribution, of this Opening Brief, and the recommendations in that section should apply to the post-test years. In its Application, PG&E proposes $158.1 million in 2015 and $175.2 million in 2016 for additional gas leak repair expenses in Major Work Category (MWC) FI. DRA recommends the Commission adopt DRA's forecasts discussed above in Section 3 of this Opening Brief. PG&E proposes to annually true-up differences between the estimated and actual proceeds of PG&E's litigation with the Department of Energy, and DRA does not oppose that request.[2384]

12.2 **Policy**

Before 1982, the base revenue requirement was generally adjusted only during General Rate Case proceedings. In the period between GRC proceedings, base rates would not change, but the utilities received additional income from customer growth. Post-Test Year, or attrition, rate adjustments were implemented in the early 1980's primarily because of the unprecedented high inflation and lower rates of customer growth and sales in the late 1970's and early 1980's. Since the mid-1980's, inflation has generally declined to more modest historical levels. The utilities have also had various forms of revenue balancing account protection from sales fluctuation. Additionally, utility fuel-related costs that had high volatility, and over which utilities have limited control, were removed from base rates and are now recovered through separate mechanisms with balancing accounts.

[2383] Ex. 90 (DRA-22), p. 4.

[2384] Ex. 90 (DRA-22), p. 2.

The GRC proceeding is used to periodically review and set reasonable rates for utilities for a specific test year, in this case, 2014. For the period between GRC proceedings, the Commission has, in some cases, granted attrition-type increases and, in other cases, has not provided such increases. In the past, the Commission has said:

> The attrition mechanism is not an entitlement. Nor is it a method of insulating the company from the economic pressures which all business experience…Neither the Constitution nor case law has ever required automatic rate increases between general rate case applications.[2385]

For example, in PG&E's 1999 GRC decision, the Commission denied attrition increases for year 2000. In D.02-02-043, the Commission granted PG&E a 2001 attrition increase of approximately $151 million. In D.03-03-034, however, the Commission denied PG&E's attrition increase request for 2002. It is clear that utilities are not automatically entitled to attrition rate increases between rate cases, even though the Commission has included provisions for post-test year rate relief in some GRC decisions.

12.3 PG&E's Post-Test Year Ratemaking Proposals

PG&E characterizes its proposed Post-Test Year Ratemaking (PTYR) mechanism for 2015 and 2016 as one which provides the utility "…with the funds it needs to provide safe and reliable service to customers, while offering offers PG&E a fair opportunity to earn the rate of return found reasonable by this Commission."[2386]

PG&E is "…asking the Commission to adopt a PTYR mechanism that models capital revenue requirement growth based on adopted test year (TY) plant additions, and, with one exception, applies escalation rates to adopted TY expense amounts. The single expense escalation exception is related to gas leak repairs where PG&E expects significant cost increases in 2015 and 2016 due to the implementation of new leak survey technology."[2387]

PG&E is "…also asking the Commission…to explicitly recognize that upon an appropriate showing, a cost of service utility such as PG&E should be allowed an adjustment for capital revenue requirement changes during the attrition period, irrespective of inflation." PG&E

[2385] D.93-12-043, 52 CPUC 2d 471, 492.

[2386] Ex. 45 (PG&E-11), p. 1-1, lines 12-14.

[2387] Ex. 45 (PG&E-11), p. 1-1, lines 23-28.

says that "[t]his ratemaking convention is necessary in order to provide utilities with growing rate base the revenues required to make the capital investments needed to provide safe and reliable service."[2388]

Using PG&E's PTYR proposals, PG&E's attrition revenue increases total $492 million in 2015 and $504 million in 2016.[2389] The estimated $492 million revenue increase in 2015 represents a 6.1% increase relative to PG&E's 2014 revenue requirement request, and the $504 million revenue increase in 2016 represents a 5.9% increase relative to PG&E's forecasted 2015 revenue requirement.

The combination of PG&E's 2014 forecasts and its post-test year proposals yield revenue requirement levels of $8.603 billion in 2015 and $9.107 billion in 2016.[2390]

12.3.1 PG&E's PTYR Increases for Expenses, Capital Additions, Rate Base and Other Revenue Requirement Changes

PG&E's PTYR proposal "…is intended to estimate changes in the cost of providing service subsequent to 2014, due to: rate base growth; expense escalation; and exogenous cost of service changes (Z-factor events)."[2391] PG&E's proposed attrition mechanism include the following seven components: (1) adjustments to labor costs; (2) adjustments to non-labor expenses; (3) adjustments to medical benefits costs; (4) adjustments to capital and rate base-related items; (5) adjustments for other revenue requirement changes; (6) adjustments, if necessary, to reflect a revised cost of capital; and (7) adjustments, if necessary, for revenue requirement changes associated with approved Z-factor events.[2392]

12.3.1.1 Labor and Labor-Related Expenses

PG&E proposes increases to labor costs (e.g., Operations & Maintenance [O&M] and Administrative & General [A&G] wages) to reflect forecast escalation rates. Labor-related expenses subject to these adjustments also include payroll taxes and the wage-related portion of benefits (excluding pension and medical plan costs).

[2388] Ex. 45 (PG&E-11), p. 1-1, line 28 thru p. 1-2, line 2.

[2389] Ex.45 (PG&E-11), p. 2-7, Table 2-1, line 36.

[2390] Ex. 90 (DRA-22), p. 67.

[2391] Ex. 45 (PG&E-11), p. 2-2, lines 23-26.

[2392] Ex. 45 (PG&E-11), p. 2-2 line 21 thru p. 2-4, line 7.

The labor adjustments proposed by PG&E are based on 2015 and 2016 wage rate increases of 2.75% for union (operating units) employees and 2.97% for non-union (A&G) employees. Overall, PG&E forecasts company-wide escalation of 2.79% per year for 2014 through 2016.[2393]

PG&E states that the "…current wage agreements with Local 1245 of the International Brotherhood of Electrical Workers and the Engineers and Scientists of California, Local 20, were ratified in July of 2012 and cover the period of January 1, 2012 through December 31, 2014. For purposes of calculating attrition increases, these agreements are assumed to set wage levels through the entire 2014 GRC period."[2394]

12.3.1.2 Non-Labor Expenses

PG&E proposes increases to non-labor (materials and services) O&M and A&G expenses, as well as property insurance. PG&E relies on Global Insight escalation rates, ranging from 1.6% to 3.3%,[2395] to estimate attrition year growth in non-labor expenses.

PG&E says it "…will not seek to adjust or true-up these rates after a final Commission decision in this proceeding."[2396]

12.3.1.3 Medical Benefits Expenses

PG&E proposes increases to medical benefits expenses, and uses escalation rates of 8.4% in 2015 and 8.2% in 2016 for its medical programs costs,[2397] as well as other cost trend forecasts for other benefit costs (e.g., dental and vision plans, disability programs, group life insurance, etc.).

12.3.1.4 Capital- Related Costs

PG&E proposes increases to capital-related costs. One component of the rate base growth is plant additions. PG&E proposes "…that the post test-year capital additions forecast for 2015 and 2016 is equal to the adopted 2014 net capital additions plus escalation…Escalation

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[2393] Ex. 45 (PG&E-10), p. 3-4, Table 3-2.

[2394] Ex. 42 (PG&E-10), p. 2-4, lines 24-29.

[2395] *See* Ex.42 (PG&E-10), p. 3-5, Table 3-3, for non-labor escalation rates by functional category.

[2396] Ex. 45 (PG&E-11), p. 2-5, lines 2-5.

[2397] Ex. 35 (PG&E-8), p. 6-18, lines 18-21.

will be fixed based on capital cost indices described in Exhibit (PG&E-10), Chapter 3, Escalation Rates."[2398] PG&E generally relies on Global Insight capital escalation rates, ranging from 1.8% to 3.7%,[2399] to estimate attrition year net plant additions.

PG&E's proposed attrition mechanism yields estimated net capital additions totaling $3.048 billion in 2015 and $3.127 billion in 2016.[2400]

Based on these forecasts, PG&E's estimated growth in total net capital additions is $74.9 million (2.52%) from 2014 to 2015, and $79.2 million (2.59%) from 2015 to 2016.

PG&E indicates that some of the rate base growth during the attrition years is driven by changes to depreciation, and estimated changes in deferred tax liabilities. For instance, PG&E forecasts "…deferred tax reversals during the attrition years, which is attributable to bonus depreciation that has greatly inflated deferred taxes (a reduction to rate base) coming into the test year."[2401] Meanwhile, PG&E says that it "…is not proposing to change the rate base elements of materials and supplies, customer advances, or working cash."[2402]

PG&E's proposed attrition mechanism yields estimated weighted-average rate base balances of $23.096 billion in 2015 and $24.715 billion in 2016.[2403] Based on these forecasts, PG&E's estimated growth in total weighted-average rate base is $1.657 billion (7.73%) from 2014 to 2015, and $1.630 billion (7.06%) from 2015 to 2016.

12.3.1.5 Other Revenue Requirement Changes

PG&E proposes other adjustments to revenue requirement due to its forecast of additional gas leak repairs costs, and estimated refunds related to Department of Energy (DOE) litigation.[2404]

[2398] Ex. 45 (PG&E-11), p. 3-3, lines 5-11.

[2399] *See* Ex. 42 (PG&E-10), p. 3-6, Table 3-4, for capital escalation rates by functional category.

[2400] Ex. 90 (DRA-22), p. 9.

[2401] Ex. 45 (PG&E-11), p. 3-1, lines 26-28.

[2402] Ex. 45 (PG&E-11), p. 3-4, lines 15-17.

[2403] Ex. 90 (DRA-22), p. 10.

[2404] Ex. 90 (DRA-22), p. 11.

12.3.1.6 Changes to Cost of Capital

PG&E proposes adjustments to post-test year return and income taxes to reflect currently adopted debt costs, equity costs, and capital structure, if necessary. According to PG&E, "…[t]he calculations included in this application use the financial parameters adopted in PG&E's most recent cost of capital D.07-12-049 and the related 2-year extension D.09-10-016."[2405]

12.3.1.7 Modified Z-Factor Mechanism

PG&E proposes "…a Z-factor mechanism to capture exogenous events that have a major impact on PG&E's cost of service, similar to those which have been adopted for SCE and Sempra. PG&E proposes a one-time $10 million deductible per event (positive or negative depending on the adjustment) and also proposes to allow an exception to the normal criteria for a few specific exogenous changes that are a normal part of doing business and do not have a disproportionate impact on PG&E."[2406]

Under PG&E's proposal,

> …adjustments will be made for revenue requirement changes associated with approved Z-factor events—defined as significant events that are beyond the utility's ability to control and cause large changes in its cost structure.2 PG&E proposes the same Z-factor event criteria as those used in the San Diego Gas & Electric Company (SDG&E) mechanism (see D.05-03-023) but proposes an exception to that criteria for exogenous changes, final as a matter of law, related to: (a) postal rate changes; (b) franchise fee changes; (c) income tax rate changes and other tax changes which are part of the same or related tax legislation; (d) payroll tax changes; and (e) ad valorem tax changes. This exception is necessary because these changes are a normal part of doing business and do not have a disproportionate impact on PG&E and therefore should be excluded under SDG&E's Z-factor criteria.[2407]

PG&E indicates that it is proposing "…a modified Z-factor mechanism…,"[2408] where Z-factor adjustments would "…apply to all years of the rate case cycle, including the TY."[2409]

[2405] Ex. 45 (PG&E-11), p. 2-3, lines 21-24.

[2406] Ex. 45 (PG&E-11), p. 1-7, lines 11-17.

[2407] Ex. 45 (PG&E 11), p. 2-3, line 25 through p. 2-4, line 5.

[2408] Ex. 45 (PG&E 11), p. 1-4, line 9.

[2409] Ex. 45 (PG&E-11), p. 2-3, footnote 2.

Implementation of PG&E's Post-Test Year Ratemaking Mechanism

PG&E indicates that, as part of its proposed PTYR mechanism, "…all escalation rates would be fixed, and the additional gas leak repair costs and DOE litigation proceeds would be subject to balancing account true-up…"[2410]

PG&E asserts that its proposed PTYR mechanism is "…a streamlined process for settling revenue requirements between GRCs. Under PG&E's proposal of fixed revenue requirement increase, attrition advice letters would only be necessary if a Z-factor event were to occur or there was a change in the adopted COC. PG&E proposes to incorporate the annual gas and electric revenue requirement changes adopted in this proceeding in PG&E's Annual Electric True-Up and Annual Gas True-Up filings."[2411]

The areas DRA disputes are discussed below.

12.4 DRA's Primary Post-Test Year Ratemaking Proposals

PG&E's forecasted Post Test Year revenue increases of $492 million (6.1%) in 2015 and $504 million (or 5.9%) in 2016 are excessive. To put PG&E's request into perspective, the proposed revenue increases for 2015 and 2016 exceed the $450 million *test year* increase authorized by the Commission[2412] in PG&E's 2011 GRC!

DRA recommends the Commission adopt a mechanism which would result in more reasonable post-test year revenue increases and encourage PG&E to manage costs, and to operate efficiently and productively between rate cases.[2413]

DRA's recommendation would have the Commission set post-test year GRC revenue increases for PG&E at 2.3% for 2015 and 2016, plus additional revenues for forecasted leak repair expenses.[2414] DRA's recommended percentage factors are guided by a recent forecast of the All-Urban Consumer Price Index (CPI or CPI-U), equal to 1.7% for 2015 and 1.9% for

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[2410] Ex.45 (PG&E-11, p. 1-7, lines 28-30.

[2411] Ex. 45 (PG&E-11, p. 1-15, lines 10-16.

[2412] D.11-05-018, mimeo., p. 2.

[2413] Ex. 90 (DRA-22), p. 13.

[2414] In Ex.78 (DRA-10, Gas Distribution Capital Expenditures), DRA has proposed a separate ratemaking mechanism which provides PG&E the opportunity to recover additional revenues in 2015 if PG&E's capital expenditures exceed DRA's forecast.

2016,[2415,2416] as well as the annual attrition increases adopted by the Commission in PG&E's 2007 and 2011 GRCs (about 2.5% and 3.0%, respectively).[2417]

Based on its forecast of PG&E's 2014 revenue requirement, DRA's recommended PTYR methodology yields estimated revenue increases of $168.4 million in 2015 and $158.7 million in 2016. These increases would yield revenue requirement levels of $6.640 billion for 2015 and $6.799 billion for 2016.

In many cases, DRA has supported and recommended using the CPI as a basis for determining attrition increases. The CPI indexing method is simple in that it eliminates the use of multiple indices that PG&E's proposal entails. For example, in D.06-05-016, the Commission acknowledged that the CPI methodology had "...been recently adopted by the Commission in determining attrition for PG&E and SDG&E…" and that "in those cases, the CPI methodology would provide reasonable results."[2418]

The post-test year revenue increases proposed by DRA are reasonable and consistent with recent attrition increases granted by the Commission to California energy utilities, with the exception of Southern California Edison Company (SCE) in its 2009 and 2012 GRCs.

In contrast, PG&E's proposed 6% per year post-test year increases significantly exceed the attrition increases granted to any of the California energy utilities during the past several years, excluding SCE in its 2012 GRC.[2419]

For example:

[2415] Ex. 90 (DRA-22), p. 14, footnote 31: IHS Global Insight Cost Planner Fourth-Quarter 2012, page 11, Purchasing Environment, Table A1, Aggregate Price and Wage Forecasts, Consumer Price Index, CPI, All Items, Urban (CPI %). (*See* Appendix 1 of this exhibit.)

[2416] Ex. 90 (DRA-22), p. 14, footnote 32: The IHS Global Insight Cost Planner First-Quarter 2013 now forecasts CPI at 1.6% for 2015 and 1.7% for 2016.

[2417] Ex. 90 (DRA-22), p. 26, footnote 33: A simple average of 1.7%, 1.9%, 2.5%, and 3.0% equals 2.275%, but DRA chose to use 2.3%.

[2418] D.06-05-016, *mimeo.*, at pp. 301 and 303.

[2419] Ex. 90 (DRA-22), p. 15, footnote 35: D.12-11-051, *mimeo.*, at p. 3, indicates that, for SCE, the Commission adopted revenue requirement levels of $5.671 billion for 2012, $6.078 billion for 2013, and $6.426 billion for 2014. Based on DRA's calculations, this equates to revenue increases of $407 million (7.2%) in 2013 and $348 million (5.7%) in 2014. However, excluding the $188 million in revenues rolled in from SCE's SmartConnect program beginning in 2013 (which were previously recovered through the Edison SmartConnect Balancing Account), the net post-test year revenue increases would have been $219 million (3.9%) in 2013.

- The Commission adopted a settlement agreement in PG&E's 2007 GRC, authorizing attrition increases of $125 million (about 2.5%) per year from 2008 through 2010.[2420]
- The Commission adopted a settlement agreement in PG&E's 2011 GRC, authorizing attrition increases of $180 million in 2012 and $185 million in 2013 (about 3.0% per year).[2421]
- The Commission adopted a settlement agreement in San Diego Gas & Electric Company's (SDG&E) and Southern California Gas Company's (SoCalGas) 2008 GRCs, authorizing attrition increases of approximately 3.1% per year from 2009 through 2011 for each of the two utilities.[2422]
- The Commission adopted a settlement agreement in Southwest Gas Corporation's 2009 GRC, authorizing attrition increases of 2.95% per year for the utility's Southern California and Northern California Divisions.[2423]
- The Commission adopted a settlement agreement in the California Pacific Electric Company's (CalPeco) 2013 GRC, authorizing a Post-Test Year Adjustment Mechanism (PTAM) for 2014 and 2015 based on the September Global Insight "U.S. Economic Outlook" forecast of CPI less a 0.5% productivity factor.[2424]
- The Commission adopted a settlement agreement in PacifiCorp's 2011 GRC, authorizing a PTAM which was a continuation of the mechanism previously authorized for PacifiCorp in its 2007 GRC (D.06-12-011) based on the Global Insight "U.S. Economic Outlook" forecast of CPI with an off-setting productivity factor of 0.5% (CPI - 0.5%) or zero.[2425]

For the SCE 2009 general rate case, the Commission authorized attrition increases of 4.25% in 2010 and 4.35% in 2011.[2426]

For the Sempra TY 2012 GRC, the Commission adopted "a variation of DRA's proposal to use the CPI—Urban approach to determine the PTY revenue requirements of SDG&E and SoCal Gas. DRA recommends using an increase of 1.9% for 2013, 2.0% for 2014, and 2.0% for 2015"[2427] The Commission found it "…reasonable to add 75 basis points (0.75%) to DRA's

[2420] D.07-03-044, *mimeo.*, at pp. 2, 10 and 11.

[2421] D.11-05-018, *mimeo.*, Attachment 1, p. 1-17, Section 3.11.2.

[2422] D.08-07-046, *mimeo.*, Appendix 3 (for SDG&E) and Appendix 4 (for SoCalGas).

[2423] D.08-11-048, *mimeo.*, Settlement Attachment 7, Sheets 1 and 2.

[2424] D.12-11-030, *mimeo.*, Appendix A, pp. 7-8 and Appendix G.

[2425] D.10-09-010, *mimeo.*, at pp. 9-10.

[2426] D.09-03-025, *mimeo.*, pp. 305-306.

[2427] D.13-05-010, *mimeo.*, p. 1010.

recommended percentages, as the attrition adjustments that should be adopted for the PTY period, i.e., 2.65% for 2013, 2.75% for 2014, and 2.75% for 2015.[2428]

If the Commission were to use the approach it just adopted for the Sempra Utilities post-test year revenue requirements, adding 75 basis points to the CPI-U as set forth in the IHS Global Insight Cost Planner First Quarter 2013, the resulting factors would be 2.35% for 2015 and 2.45% for 2016.[2429] Measured against the Commission's past decisions, and most recent review of appropriate post-test year revenue requirement increases, PG&E's proposed increases of 6.1% in 2015 and 5.9% in 2016 are clearly excessive.[2430]

In Rebuttal, PG&E attaches what it calls a "study," later supplemented with color charts and extensive calculations, that purports to show the following:

Assuming PG&E's operating expenses increased by DRA's 2.3 percent (which is significantly lower than PG&E's estimates), PG&E would have to reduce 2015 capital additions from PG&E's forecast by over $2 billion and from DRA's own recommended test-year level by $1.1 billion (a little over 50 percent). Assuming instead that PG&E were to maintain 2015 and 2016 capital additions levels at the DRA's recommended test-year amount of $2.1 billion (adjusted for escalation), PG&E would have to reduce operating expense by $21.4 million in 2015, and additional $37.0 million in 2016. Clearly the operating expense and capital levels inherent in DRA's attrition proposal would underfund utility operations and have adverse impacts on the quality and safety of PG&E's service.[2431]

But, as DRA's witness explained on cross examination, "it is just math."[2432] Those are just the numbers that fall out given the inputs PG&E provided for a model run. If safety and reliability is really the 'top priority' then the revenue requirement PG&E gets should be directed at capital investments that meet those needs, as opposed to asking the Commission to order

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[2428] D.13-05-010, *mimeo.,* p. 1011.

[2429] See Ex. 90 (DRA-22), p. 14, footnote 32.

[2430] Ex. 90 (DRA-22), p. 17, footnote 44: PG&E has modeled significant rate base increases for the post-test years. PG&E has not modeled the 50% bonus depreciation provision for 2014, 2015 and 2016, which impacts the deferred tax balance—this is one of the factors driving up PG&E's rate base forecast. (PG&E refers to this as deferred tax reversals.)

[2431] Ex. 65 (PG&E- 26), p. 1-10.

[2432] 28 RT 3700, Tang/DRA.

ratepayers to reward PG&E employees with STIP payouts of $100 million a year[2433] and fund capital projects as well.

DRA continues to recommend that the Commission adopt post-test year increases of 2.3% in 2015 and 2016 for PG&E's 2014 GRC, plus additional revenues for gas leak repair expenses.[2434]

12.4.1.1 Other Revenue Requirement Changes Gas Leak Repairs

PG&E proposes post-test year revenue adjustments associated with gas leak repair costs, DOE litigation proceeds, and 2011-2013 Photovoltaic (PV) Program cost savings. As noted above, of these, DRA disputes PG&E's post-test year revenue adjustment proposal for gas leak repairs.

PG&E proposes revenue requirement increases in 2015 and 2016, subject to balancing account treatment, to account for forecasted additional gas leak repair expenses. DRA opposes PG&E's proposal for a 2-way balancing account, and the recommendation contained in Section 3, above, in this Opening Brief also applies to the attrition years.[2435]

Regarding leak repairs, PG&E forecasts expenses of $158.1 million in 2015 and $175.2 million in 2016 in MWC FI, compared to $102.1 million in 2014. In other words, PG&E forecasts incremental costs of $56.0 million[2436] in 2015 and $17.1 million[2437] in 2016.

DRA forecasts $35.6 million of expenses for MWC FI in 2014. By using that DRA forecast as the starting point, and increasing this forecast by adding pro-rated amounts of PG&E's forecasted increases in 2015 and 2016, DRA estimates MWC FI expenses of $55.1 million in 2015, and $61.1 million in 2016, as shown below. In other words, DRA forecasts incremental costs of $19.5 million[2438] in 2015 and $6.0 million[2439] in 2016.[2440] DRA

[2433] 28 RT 3701, Tang/DRA.

[2434] Ex. 90 (DRA-22), p. 17.

[2435] Ex. 90 (DRA-20), p. 17.

[2436] $158.1 million - $102.1 million = $56.0 million.

[2437] $175.2 million - $158.1 million = $17.1 million.

[2438] $55.1 million - $35.6 million = $19.5 million.

[2439] $61.1 million - $55.1 million = $6.0 million.

[2440] Ex. 90 (DRA-22), p. 18.

recommends the Commission adopt these estimates for purposes of authorizing additional post-test year revenues for leak repair expenses in 2015 and 2016.[2441]

Exogenous Cost Changes

In this GRC, PG&E proposes "…a modified Z-factor mechanism…,"[2442] where Z-factor adjustments would "…apply to all years of the rate case cycle, including the TY."[2443] In other words, PG&E proposes a Z-factor mechanism which is significantly different (i.e., more generous to PG&E) than the one authorized by the Commission in PG&E's 2011 GRC.[2444]

DRA does not dispute the concept of the utility having a Z-factor mechanism in place with the same Z-factor event criteria as those used in the SDG&E mechanism authorized in D.05-03-023. In fact, in PG&E's 2011 GRC, DRA had recommended that the Commission adopt a similar mechanism for PG&E. The Commission-adopted Z-factor mechanisms are a way to protect both the utilities and the ratepayers by allowing for post-test year adjustments for unexpected and uncontrollable events. DRA does oppose, however, PG&E's request for special treatment for the Z-Factor Mechanism.

In PG&E's TY 2011 GRC, PG&E proposed a PTYR mechanism which would automatically allow revenue requirement adjustments for changes in expenses due to the five exogenous, uncontrollable factors: (1) postal rate changes; (2) franchise fee changes; (3) income tax rate changes and other tax changes which are part of the same or related tax legislation; (4) payroll tax changes; and (5) *ad valorem* tax changes.[2445] In the TY 2011 GRC, DRA disputed PG&E's proposal because it only protected PG&E and its and its shareholders, not its ratepayers.[2446]

The Commission decision resolving the TY 2011 GRC ultimately adopted an attrition mechanism for PG&E which allowed "…2012 and 2013 revenue requirement adjustments for exogenous changes, limited to five factors (postage rate changes, franchise fee changes, income

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[2441] Ex. 90 (DRA-22), p. 19.

[2442] Ex. 45 (PG&E-11), p. 1-4, line 9.

[2443] Ex. 45 (PG&E-11), p. 2-3, footnote 2.

[2444] Ex. 90 (DRA-22), p. 20.

[2445] Ex. 90 (DRA-22), p. 21, footnote 55 citing A.09-12-020, Ex. PG&E-9, p. 2-4, lines 7-12.

[2446] Ex. 90 (DRA-22), p. 21, footnote 56 citing A.09-12-020, Ex. DRA-21, pp. 21-22.

tax rate changes, payroll tax rate changes, *ad valorem* tax changes), with a $10 million deductible amount applicable to each factor each year."[2447]

The Commission should do the same in this GRC. Any revenue adjustments associated with changes in post-test year expenses due to the five factors identified above should be part of a Z-factor mechanism subject to a deductible, not separate and distinct from it. PG&E's proposal is one-sided and is more likely to benefit the company and its shareholders, rather than its ratepayers. DRA recommends that the Commission reject PG&E's request for a special exception to the criteria for exogenous changes.

DRA also opposes PG&E's request that Z-factor adjustments apply to all years of the rate case cycle, including the test year. DRA is unaware of any Commission decision that has granted test year Z-factor adjustments to a major California energy utility during the test year. The Commission has granted Z-factor adjustments exclusively for attrition years.

In its Direct Testimony, PG&E refers to D.05-03-023, but that decision, by DRA's reading, authorized a Z-factor mechanism specifically for SDG&E's and SoCalGas' ***post-***test years 2005, 2006, and 2007. The Findings of Fact 52 through 55 of that decision state that the Z-factor mechanism only applied to the post-test years.[2448] Most recently, in SCE's 2012 GRC, the Commission approved for SCE the "…[c]ontinuation of the Z factor…in attrition years."[2449]

Even PG&E does not dispute that past Z-factor adjustments have applied exclusively to the attrition years. In fact, it seems from PG&E's Rebuttal testimony that PG&E "would not object to limiting Z-factor adjustments to the attrition years in this GRC."[2450]

That being the case, and since PG&E has offered no good reason why the Commission should deviate from this practice, DRA continues to recommend that the Commission reject PG&E's request that Z-factor adjustments apply to the test year.

Any Z-factor mechanism which the Commission authorizes for PG&E in this GRC should encompass exogenous changes that can ***de***crease utility costs (such as tax rate changes or

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[2447] D.11-05-018, *mimeo*., Attachment 1, p. 1-17, Section 3.11.3 ("Exogenous Changes").

[2448] D.05-03-023, *mimeo*., at pp. 64-65; 2005 Cal. PUC LEXIS 127.

[2449] D.12-11-051, *mimeo*., at p. 876, Conclusions of Law #523 (4th bullet).

[2450] Ex. 65 (PG&E-26), p. 1-14, lines 19-22.

tax law changes), rather than one limited to changes that increase the utility's costs.[2451] Such a Z-factor mechanism should also be consistent with the Z-factor criteria outlined by in D.05-03-023. It should identify exogenous cost changes that qualify for Z-factor treatment,[2452] but there be no presumption of recovery of an identified Z-factor event until the incurred costs have been found to be reasonable. Finally, DRA recommends that a Z-factor mechanism only be established for and effective during the attrition years, and not for the test year.[2453]

12.5 DRA's Alternative Post-Test Year Ratemaking Proposal

If the Commission does not adopt DRA's primary recommendation on PG&E's post-test year revenue increases, and instead relies on a mechanism similar to PG&E's proposal, then DRA recommends certain changes to the PTYR method PG&E proposes. These are to the bonus depreciation provision in PG&E's post-test year capital-related adjustments, and to certain expense related adjustments as described below.

12.5.1 Post-Test Year Capital-Related Adjustments

PG&E proposes "…that the post test-year capital additions forecast for 2015 and 2016 is equal to the adopted 2014 net capital additions plus escalation…Escalation will be fixed based on capital cost indices described in Exhibit (PG&E-10), Chapter 3, Escalation Rates."[2454] PG&E generally relies on Global Insight capital escalation rates, ranging from 1.8% to 3.7%,[2455] to estimate attrition year net plant additions.

DRA does dispute this PG&E proposal, which is similar to the approach adopted by the Commission in SCE's test year 2006[2456] and 2012[2457] GRC decisions. DRA is, however, concerned with PG&E's rate base growth estimates of over 7.0% per year in 2015 and 2016.

Historically, PG&E's weighted-average rate base growth has averaged about 6.1% per year during the 5-year period from 2007 thru 2011, and about 4.8% per year during the 10-year

[2451] Ex. 90 (DRA-22), p. 23.

[2452] D.05-03-023, *mimeo.*, at p. 30.

[2453] Ex. 90 (DRA-22), p. 23.

[2454] Ex. 45 (PG&E-11), p. 3-3, lines 5-11.

[2455] *See* Ex. 42 (PG&E-10), p. 3-6, Table 3-4, for capital escalation rates by functional category.

[2456] D.06-15-016, *mimeo.*, at pp. 305-306.

[2457] D.12-11-051, *mimeo.*, at p. 608.

period from 2002 thru 2011.[2458] According to PG&E, the estimated rate base growth during the attrition years is caused, in part, by deferred tax reversals as the bonus depreciation provisions from the Tax Relief Act of 2010 are scheduled to expire at the end of 2013.

DRA assumes that the 50% bonus depreciation provision will be extended into 2014, and has reflected such an outcome in its Results of Operations (RO) model. DRA also assumes that the 50% bonus depreciation provision will be extended into 2015 and 2016 and should be appropriately modeled. If the bonus depreciation provisions are not extended, or are extended with a different bonus percentage, then PG&E should seek an appropriate adjustment to its revenue requirement by advice letter.

12.5.2 Post-Test Year Expense-Related Adjustments

DRA does not oppose the general concept of determining attrition expense increases by escalating the adopted 2014 expense levels, but DRA does oppose PG&E's post-test year expense forecasts for MWC FI (gas leak repairs) and its proposed escalation rates for medical benefits costs and labor costs in 2015 and 2016.

Gas Leak Repairs

PG&E forecasts leak repair expenses of $158.1 million in 2015 and $175.2 million in 2016 in MWC FI, compared to $102.1 million in 2014. PG&E requests additional revenues in the post-test years, to cover forecasted incremental costs of $56.0 million in 2015 and $17.1 million in 2016 for leak repairs. DRA forecasts $35.6 million of expenses for MWC FI in 2014, $55.1 million in 2015, and $61.1 million in 2016, or incremental costs of $19.5 million in 2015 and $6.0 million in 2016. As discussed earlier, DRA's primary recommendation is that the Commission adopt these DRA forecasts.

If the Commission is concerned about uncertainties[2459] associated with DRA's attrition year forecasts for MWC FI, then DRA proposes an alternative mechanism. If during the post-test years PG&E incurs expenses for gas leak repairs that exceed DRA's forecasted amounts, the Commission can allow PG&E to file Tier 2 advice letters[2460] in the ensuing years, requesting

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[2458] Ex. 90 (DRA-22), p. 24, footnote 67: Calculated from data provided by PG&E in response to data request DRA-PG&E-072-CKT, Question 1.b.

[2459] Due to PG&E's reliance on a new technology, the Piccaro Surveyor.

[2460] Advice letters could be filed by January 31, to be effective March 1 of the following year. For

incremental revenues necessary to cover the increased costs up to, but not exceeding, a cost cap which the Commission deems appropriate.[2461] The Commission could set DRA's forecast as a floor and the cost cap as a ceiling.

This alternative approach: (1) still allows PG&E the opportunity to recover higher revenues if warranted; (2) does not burden ratepayers with potentially higher revenue requirements in 2015 and 2016 for costs that may not materialize; and (3) does not force customers to pay for the cost of repairing leaks that PG&E does not actually find.[2462]

Medical Benefit Costs

PG&E proposes to escalate medical benefits costs by 8.4% in 2015 and 8.2% in 2016. DRA recommends that the medical benefits costs be escalated by 6.4% in 2015 and 6.3% in 2016,[2463],[2464] based upon the forecasted group health insurance escalation rates appearing in the IHS Global Insight Cost Planner Fourth-Quarter 2012. DRA's recommendation is consistent with PG&E's proposed medical escalation rates of 5.4% for 2012, 6.4% for 2013, and 5.4% for 2014.[2465]

Global Insight is the same source used for non-labor escalation rates by both PG&E and DRA. Also, the utilities use Global Insight's forecasted interest rates to update long term debt and preferred stock costs in the Cost of Capital proceedings.[2466]

In Rebuttal, PG&E says that:

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example, PG&E would file an advice letter by January 31, 2016 for expenses incurred in 2015 which exceed the adopted 2015 amounts for MWC FI.

[2461] A cost cap which blends forecasts by DRA and PG&E could be based on DRA's test year forecast and PG&E's post-test year increment forecasts. To illustrate, a cap for 2015 could be $35.6 million + $56.0 million = $91.6 million, and for 2016 could be $91.6 million + $17.1 million = $108.7 million.

[2462] Ex. 90 (DRA-22), p. 26.

[2463] Ex. 90 (DRA-22), p. 26, footnote 71: IHS Global Insight Cost Planner Fourth-Quarter 2012, p. 151, Additional Forecast Tables, Table A1, Corporate Expenses, Health Care Benefits, ECI, Group Health Insurance (ECIHI %). (*See* Appendix 1 of this exhibit.)

[2464] Ex. 90 (DRA-22), p. 26, footnote 72: The IHS Global Insight Cost Planner First-Quarter 2013 now forecasts Group Health Insurance (ECIHI %) at 5.7% for 2015 and 5.6% for 2016. DRA would not be opposed to the Commission adopting the ECIHI forecast from the IHS Global Insight Cost Planner First-Quarter 2013.

[2465] Ex. 37 (PG&E-8, workpapers Supporting Chapters 5, 6, 7, 8, 9), p. WP 6-10.

[2466] D.12-12-034, *mimeo.*, at p. 14.

> Global Insight's health care escalation factors are not appropriate to forecast PG&E's medical costs because these factors are based on a national health care index that does not accurately predict PG&E's health care cost increase. Global Insight's data is skewed by employers that do not have unionized workforces and by employers who have abandoned health care plans altogether.[2467]

This is a meaningless criticism. Global Insight's health care escalation factors also include information from employers who *do* have unionized workforce, and by employers that have *not* abandoned health care plans altogether. Moreover, DRA's proposed escalation rates of 6.4% for 2015 and 6.3% for 2016 are actually higher than the projections of the Centers for Medicare and Medical Services (CMS). CMS projects, over the period of 2015 to 2012, health spending to grow at an average rate of 6.2% annually."[2468] The report goes on to say that "[f]or 2015-21, growth in private health insurance premiums is projected to slow somewhat and to average 5.9 % annually, in part due to an expectation that some large employers of low –wage workers will discontinue coverage resulting in their employers gaining coverage through Medicaid or the exchange plans."[2469] PG&E is not an employer of low-wage workers and is unlikely to seek to eliminate its unions, or abandon providing health care coverage;[2470] DRA's proposed medical escalation rates are entirely consistent with the analysis of experts in the field.

Wage Escalation Rates

For purposes of calculating attrition increases, PG&E has proposed labor adjustments based on 2015 and 2016 wage rate increases of 2.75% for union (operating units) employees and 2.97% for non-union (A&G) employees, and forecasts company-wide escalation of 2.79% per year for 2014 through 2016.[2471]

PG&E does not have negotiated wage escalation rates in place for 2015 and 2016. Given that wage increases have yet to be established for those two post-test years, PG&E has an opportunity to attempt to control its labor costs for 2015 and 2016. The Commission should reject the proposed 2.79% per year wage rate increase. This proposed wage rate increase does

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[2467] Ex. 62 (PG&E-23), p. 7-11.

[2468] Ex. 62 (PG&E-23), Attachment B, p. 7B1.

[2469] Ex. 62 (PG&E-23), Attachment B, p. 7B2.

[2470] 23 RT 2921-2922, Choy/PG&E.

[2471] Ex. 42 (PG&E-10), p. 3-4, Table 3-2.

not provide PG&E management with the incentive to negotiate rates more consistent with forecasted wage rate increases and to better control the level of its wages and salaries. PG&E's total compensation exceeds the comparable companies by almost 10%, and, as discussed later, PG&E has granted wage rate increases well in excess of the utility industry in recent years. PG&E clearly needs some incentive to control the labor costs it seeks to pass off to its ratepayers.

As the Commission noted in its decision in the TY 2012 Edison GRC:

We do not embrace SCE's premise that whatever wages and increases are included in a collective bargaining agreement with its represented workers are *ipso facto* reasonable for purposes of rate recovery or labor escalation.[2472]

If the costs associated with PG&E's assumed wage increases are automatically passed-through to ratepayers, there is practically no incentive for PG&E management to aggressively negotiate, or rein in labor costs, in order to minimize ratepayer impacts.

DRA recommends tying PG&E's attrition rate increases to the CPI. Instead of automatically relying on PG&E's wage increase assumptions for 2015 and 2016, the Commission should adopt a less costly alternative. Even though Global Insight forecasts wage escalation rates of 2.1% for 2015 and 2.2% for 2016 (see Table 22-6), DRA recommends a PTYR mechanism which incorporates a recent forecast of CPI-U equal to 1.7% for 2015 and 1.9% for 2016[2473] as a proxy for PG&E's wage escalation.

In this case, the CPI is a proxy for wage escalation. As the Bureau of Labor Statistics (BLS) website's "Addendum to Frequently Asked Questions" states:[2474]

The CPI is often used to adjust consumers' income payments (for example, Social Security) to adjust income eligibility levels for government assistance and to automatically provide cost-of-living wage adjustments to millions of American workers. As a result of statutory action the CPI affects the income of millions of Americans. Over 50 million Social

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[2472] D.12-11-051, mimeo., at p. 598.

[2473] Ex. 90 (DRA-22), p. IHS Global Insight Cost Planner Fourth-Quarter 2012, page 11, Purchasing Environment, Table A1, Aggregate Price and Wage Forecasts, Consumer Price Index, CPI, All Items, Urban (CPI %). (See Appendix 1 of this exhibit.) DRA would not be opposed to the Commission adopting the CPI forecast from the IHS Global Insight Cost Planner First-Quarter 2013.

[2474] http://www.bls.gov/cpi/cpiadd.htm, emphasis added.

Security beneficiaries, and military and Federal Civil Service retirees, have cost-of-living adjustments tied to the CPI. In addition, eligibility criteria for millions of food stamp recipients, and children who eat lunch at school, are affected by changes in the CPI. ***Many collective bargaining agreements also tie wage increases to the CPI***.

In Rebuttal, PG&E says that, if the Commission were to adopt CPI for the post test year wage escalation, "PG&E workers would lose over 2.5% worth of purchasing power in just these two years."[2475] Even if true, it is not clear to DRA why PG&E's ratepayers should be solely responsible for ensuring that PG&E workers retain purchasing power. PG&E's suggestion that adoption of CPI for 2015 and 2016 will lessen PG&E's competitiveness has no support in the record.[2476]

In any event, the results of the Total Compensation study further support DRA's proposed labor escalation rates.[2477] The Total Compensation Study results presented in this rate case shows that PG&E's total compensation (annual cash compensation plus the value of employee benefits) is 9.9% above market.[2478] PG&E is beyond the + / - 5% margin of error assumed by the Commission for these studies.[2479]

13 SETTLEMENTS AND JOINT PROPOSALS

13.1 Center for Accessible Technology

DRA has no position on this issue at this time.

13.2 Joint Parties

DRA has no position on this issue at this time.

[2475] Ex. 64 (PG&E-25), p. 1-11.

[2476] 23 RT 2932, Masters/PG&E.

[2477] Ex. 90 (DRA-22), p. 32.

[2478] Ex. 35 (PG&E-8), p.3-7, Table 3-2, line 7.

[2479] According to D.09-03-025, *mimeo.*, at p. 127, Total Compensation "…study results indicate that the compensation levels sought by SCE are generally at market, with the overall compensation level 0.9% above market levels, well within the margin of error assumed by the Commission for these studies of + / - 5%." Also, see other references cited in Ex. DRA-14 (Human Resources Expenses, Part 1 of 2).

13.3 Small Business Utility Advocates

DRA has no position on this issue at this time.

14 GLOSSARY

14.1 Acronyms and Abbreviations

14.2 Major Work Categories

15 CONCLUSION

For all the foregoing reasons, and the reasons set forth in its testimony, DRA asks that the Commission adopt its recommendations.

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