PREPARED TESTIMONY OF THOMAS J. LONG ON CUSTOMER IMPACTS, COST RESPONSIBILITY, 2011-2014 CAPITAL COSTS AND OTHER POLICY ISSUES

Pacific Gas and Electric Company
2015 Gas Transmission and Storage Rate Case
A.13-12-012

SUBMITTED ON BEHALF OF
THE UTILITY REFORM NETWORK

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PREPARED TESTIMONY OF THOMAS J. LONG

I. Introduction and Summary

This testimony is presented on behalf of The Utility Reform Network ("TURN") by Thomas J. Long, TURN's Legal Director. Since September 2011, Mr. Long has served as TURN's lead attorney and director of policy in every major Commission proceeding relating to natural gas pipeline safety, including PG&E's PSEP proceeding (R.11-02-019) and the pending enforcement proceedings against PG&E relating to the San Bruno explosion and its causes (I.12-01-007), PG&E's recordkeeping problems (I.11-02-016), and alleged class location violations by PG&E (I.11-11-009). A summary of Mr. Long's qualifications is attached as Appendix A.

This testimony addresses the following issues:

- The affordability of the huge revenue requirement and rate increases that PG&E requests;
- PG&E's claim that these huge increases are justified by changes in law;
- PG&E's methodology for scoring risk mitigation programs and alternatives;
- The need for shareholders to be held responsible for a significant portion of PG&E's proposed costs;
- The $700 million of 2011-2014 capital costs above authorized levels that PG&E seeks to roll into rate base;
- Ratemaking adjustments other than shareholder responsibility for costs;
- TURN's recommendation to limit this rate case cycle to two years and to have a unified revenue requirements general rate case (GRC) for PG&E in 2017; and

- TURN's recommendation that the integrity management balancing account be a one-way account, rather than the two-way account proposed by PG&E.

II. PG&E's Drastic Rate Increases Would Threaten the Health and Safety of Vulnerable Customers Who Cannot Afford Big Rate Hikes for Gas Service

As TURN has already pointed out in its Protest, to the best of TURN's knowledge, PG&E has never before proposed such huge revenue requirement and rate increases in a GT&S case.

A. PG&E Proposes Massive Revenue Requirement Increases

Whether or not one includes the PSEP component of revenue requirement in the calculation, the proposed increase is enormous. If PSEP revenue requirements are excluded, in 2015, the GT&S revenue requirement would increase from the current $581.5 million to $1.187 billion, a 104% increase over current levels – without even counting the substantial additional proposed increases for 2016 and 2017.[1] If PSEP revenue requirements are included, the current "PSEP-in" revenue requirements would increase from $715.4 million in 2014 to $1.286 billion in 2015, $1.347 billion in 2016 and $1.515 billion in 2017,[2] a 118% increase over the three-year period.

B. PG&E Proposes Huge Increases to the GT&S Rate Components for Residential Customers

Under PG&E's proposal, residential customers would bear a heavy burden from these revenue requirement increases. As shown in Table 1 below, the components of residential rates that are affected by this GT&S case would increase significantly.

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[1] TURN Protest, p. 3.
[2] PG&E Direct, p. 18-1.

Table 1
Changes to GT&S Residential Rate Components ($/dth)[3]

	2014	2015	2016	2017	% Change from 2014
Local Transmission (includes PSEP)	.7197	1.959	2.109	2.371	229%
Backbone Capacity	.2364	.4300	.4450	.5070	114%
Storage	.2008	.2800	.2760	.2860	42%
Backbone Usage	.1148	.1390	.1510	.1670	45%
Total	**1.272**	**2.808**	**2.981**	**3.331**	**162%**

C. Even Without Considering Expected GRC Rate Increases, the Proposed GT&S Rate Hikes Would Significantly Increase Residential Customer Bills

The customer bill impact of these large increases to the GT&S rate components is muted to some extent by the fact that, for residential customers, the end user rate consists of other components that are not affected by this case. The most significant of those non-GT&S components are the distribution rate component and the cost of the gas commodity.[4] Even so, the average monthly bill impacts of PG&E's GT&S proposal would be significant, a $5.80 or 12.6% increase to non-CARE residential customer gas bills in 2015.[5] PG&E's proposals for 2016 and 2017 would add 1.3% and 2.5% respectively to customer bills, which equates to an additional $2.00 for non-CARE monthly bills.[6] Low-income CARE customers would face these same average monthly bill <u>percentage</u> increases, although absolute dollar increases would be slightly lower because of lower monthly usage by CARE customers.[7]

[3] Source: PG&E response to TURN 23-2, Attachment 1.
[4] PG&E Direct, Table 17-C, p. 17AtchA-3.
[5] PG&E response to TURN 23-2.d.
[6] *Id.*
[7] *Id.*

D. Combined with Expected GRC Rate Increases, the Proposed GT&S Rate Hikes Would Drive Up Residential Customer Bills By Almost 30% in 2015

It is important for the Commission to recognize that PG&E's residential gas customers are coping with other significant rate increases. According to PG&E, the PSEP rate increase ordered in Decision 12-12-030 has already added an average of $1.36 per month to residential customer bills. More significantly, customers will soon be forced to absorb another significant rate increase emerging out of PG&E's 2014 GRC for PG&E's distribution system. At the time of preparing this testimony, a proposed decision (PD) is pending, but the final decision has not been issued. Based on the increased revenue requirements in the PD, the combined effect on PG&E's bundled residential gas rates of its GT&S proposal combined with the 2014 GRC would be as shown in Table 2.

Table 2
Combined Effect of GT&S and 2014 GRC (PD) on Bundled Customer Rate ($/therm)[8]

	2014 w/o GRC	2014 w/ GRC	2015 w/ GT&S and GRC	2016 w/ GT&S and GRC	2017 w/ GT&S and GRC
Bundled Rate[9]	1.221[10]	1.366	1.569	1.629	1.625
Cumulative % increase		11.9%	28.5%	33.4%	33.1%

As a result, PG&E's GT&S proposal combined with the GRC rate increase (assuming the GRC decision is identical to the PD) would cause residential CARE and non-CARE customer

[8] Source: PG&E response to TURN 27-1 and TURN 27-1 Att. 1. As PG&E explains in its response to TURN 27-1, PG&E assumes a two-year amortization of the GRC revenue shortfall from the delay in issuance of the GRC decision.
[9] The bundled rate includes all of the residential rate components shown in Table 1, plus other rate elements, including components for distribution, gas commodity costs, public purpose program surcharges. See PG&E Direct, p. 17AtchA-3, Table 17-C, for a full list of the rate components.
[10] From PG&E Direct, p. 17-11, Table 17-5. In its response to TURN 27-1, PG&E uses a higher 2014 rate without GRC impacts, apparently because PG&E does not include the effect of the PSEP Update rate reduction, as PG&E does in Table 17-5.

gas bills to increase from current levels by painful amounts -- 28.5% in 2015 and 33% in 2016 and 2017. Using PG&E's estimate of a $46.40 average monthly bill for non-CARE customers,[11] a 33% increase translates to an average $15.31 monthly bill increase, or $184 per year. For low-income CARE customers, using PG&E's estimated $34.50 average monthly bill, the monthly increase would be $11.49 or $138 per year.

Of course, PG&E's use of average monthly bills masks the huge variation in residential customer gas usage – and hence bills -- over the course of a year. In 2013, for CARE customers, the average monthly usage varied from a low of 16 therms to a high of 74 therms. For non-CARE customers, the variation was from 16 to 78 therms.[12] In a peak winter month, a 33% rate increase would mean that a non-CARE customer using 78 therms would have to pay an additional $31.40 for that month.[13]

E. PG&E Did Not Give Sufficient Consideration to the Affordability Impacts of Its GT&S Proposal

Although PG&E claims that affordability was an important consideration in developing its proposal, there is little evidence that it conducted much, if any, rigorous analysis of affordability impacts. The only document that PG&E was able to provide TURN that showed an internal analysis of bill impacts – an August 28, 2013 presentation to two PG&E officers -- estimated only a 10% residential gas bill increase in 2015 from the proposal under consideration.[14] Either PG&E developed a more costly proposal after that point, or the analysis failed to consider all of the rate impacts that caused the 12.6% GT&S only bundled bill increase

[11] PG&E response to TURN 23-2.d.
[12] PG&E response to TURN 27-2 and TURN 27-2 Att. 1.
[13] 78 therms x $ 1.22/therm x 33%. Only about 5% of PG&E CARE and non-CARE customers have signed up for the Balanced Payment Plan. (PG&E response to TURN 27-4.)
[14] PG&E response to TURN 23-3 Supp 01, Att. 1. The response also references TURN 1-1, Att. 26, but that document – a June 6, 2013 Session 1 document -- does not contain any analysis of the affordability of the proposal under consideration (even though it professes that affordability is a key goal).

for 2015 that PG&E ultimately proposed. In any event, prior to submitting its proposal to the Commission, PG&E never analyzed the combined impact of its GRC and GT&S requests.[15] Nor did PG&E conduct any analysis of its GT&S proposal on potentially vulnerable groups of customers.[16]

F. By Increasing Shutoffs, Unaffordable Rates Pose Significant Health and Safety Risks

In California, "light and heat are basic human rights."[17] The absence of energy utility services is a serious public health and safety issue. As the United States Supreme Court stated in *Memphis Light, Gas & Water Division v. Craft*, "Utility service is a necessity of modern life; indeed, the discontinuance of water or heating for even short periods of time may threaten health and safety."[18] The Commission has likewise recognized that utility customers are physically harmed by the termination of electric and/or natural gas utility service for nonpayment.[19]

For this reason, the Commission, in the face of anticipated increases in natural gas prices in the winter of 2005-2006, concluded in D.05-10-044 that the electric and gas utilities should take "extraordinary steps to ensure that residential customers struggling to pay higher bills this winter are able to continue receiving gas and electric service."[20] Preventing disconnections due to unaffordable bills was, according to D.05-10-044, "an urgent matter."[21] Indeed, the Commission more recently opened Rulemaking 10-02-005, *Order Instituting Rulemaking on the Commission's Own Motion to address the issue of customers' electric and natural gas service*

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[15] PG&E response to TURN 23-4.
[16] PG&E responses to TURN 23-5 and 23-6.
[17] California Stats 1975, ch. 1010, Section 1(a).
[18] *Memphis Light, Gas & Water Division v. Craft* (1978) 436 U.S. 1, 18.
[19] D.07-09-041, issued in A.02-11-017 / I.03-01-012 / A.02-09-005, pp. 40-41.
[20] D.05-10-044, issued in R.04-01-006, p. 27.
[21] D.05-10-044, p. 6.

disconnection, in recognition of the importance of preventing residential disconnections for nonpayment because "utility service is a matter of health and safety."[22]

Unfortunately, despite the Commission's efforts in that rulemaking to reduce disconnections for non-payment, they are once again on the rise for PG&E customers, even though the anticipated large electric and gas rate increases from the 2014 GRC have not yet gone into effect (as of the time of preparing this testimony). The following table shows PG&E's disconnections for non-payment since 2006.

Table 3
PG&E Disconnections for Non-Payment

	2010	2011	2012	2013	2014
Jan	11,368	15,421	20,037	16,805	21,139
Feb	14,194	14,884	24,603	20,565	25,882
Mar	17,717	9,310	21,689	27,475	31,674
Apr	17,776	15,290	21,324	20,318	22,362
May	17,201	17,452	23,629	27,423	26,240
Jun	21,179	16,664	18,356	18,921	21,007
Jul	10,518	14,919	19,462	22,232	
Aug	12,251	17,633	19,388	20,260	
Sept	12,542	17,008	17,197	23,372	
Oct	16,296	20,339	22,023	24,042	
Nov	14,562	16,857	17,545	18,367	
Dec	13,467	12,979	9,885	12,101	
Annual	179,071	188,756	235,138	251,881	148,304
Sum: Jan-Jun	99,435	89,021	129,638	131,507	148,304

Source: PG&E's R.10-02-005 December 2011 Disconnections Report (2010, 2011 data); PG&E's R.10-02-005 December 2012 Disconnections Report (2012 data); PG&E's R.10-02-005 December 2013 Disconnections Report (2013 data); PG&E's R10-02-005 June 2014 Disconnections Report (2014 data)

[22] Order Instituting Rulemaking 10-02-005, issued Feb. 5, 2010, pp. 1, 6.

As Table 3 shows, since 2010, disconnections have begun to accelerate rapidly, with 2014 on a pace to set a dubious record that will no doubt be made even higher by the GRC rate increase that will go into effect later this year. Huge bill increases from this case would surely exacerbate the acceleration of PG&E disconnections and the attendant damage to the health and safety of PG&E's customers.

III. PG&E's Claim That Its Huge Proposed Rate Increases Are Necessary to Meet a New and Higher Standard Does Not Ring True

In an obvious strategy to divert attention away from its well-documented shortcomings in the management of its gas transmission system, PG&E attempts to attribute the need for such extreme revenue requirement and rate increases to new legal requirements that did not exist at the time of the last GT&S rate case. PG&E points particularly to SB 705's statement that safety should be the top priority for gas utilities and SB 705's use of the phrase "best practices," as well as the Commission's decision in D.11-06-017 to require a qualifying pressure test for all pipe segments.[23]

It is true that the pressure test requirement of D.11-06-017 is new and responsible for significant additional cost. But PG&E exaggerates the change that was brought about by SB 705. That legislation does say that safety is the highest priority, but such a statement of policy does not mean that safety was a lower priority before SB 705 went into effect. To the contrary, according to a PG&E data request response, "safety has always been PG&E's top priority."[24] Thus, as far as PG&E is concerned, SB 705 did not alter the top priority that PG&E claims it has always given to safety.

In addition, PG&E ignores a key element of SB 705, which directs the Commission to "take all reasonable and appropriate actions necessary to carry out the safety priority policy . . .

[23] PG&E Direct, pp. 1-2 to 1-3.
[24] PG&E response to TURN 31-2.

consistent with the principle of just and reasonable cost-based rates."[25] The underlined language is a clear reference to the "just and reasonable rate" requirement of PU Code Section 451, which continues to serve as the standard that PG&E must satisfy in rate cases such as this.

PG&E also exaggerates the import of the phrase "best practices" in SB 705. PG&E seems to think that the phrase mandates that each and every best practice that it can identify be adopted and funded, regardless of cost and regardless of whether one best practice renders another best practice inefficient or superfluous. As one would expect, SB 705 is not as inflexible and profligate with ratepayer money as PG&E supposes. What the legislation actually says is that the utilities' overall gas safety plans, not each and every activity, should be consistent with gas industry best practices. When it is recognized that the company's overall plan should follow best practices and that rate case proposals must meet the just and reasonable rate standard, it is clear that efficiency and cost-effectiveness must be a key part of the utility's rate case showing. Indeed, one would expect that achieving safety goals cost-effectively and at reasonable cost would be a key industry best practice. Unfortunately, efficiency and cost-effectiveness do not appear on PG&E's lengthy list of best practices.[26]

Furthermore, nothing in the past stopped PG&E from seeking funding for industry best practices that went beyond the minimum requirements of federal safety regulations and General Order (GO) 112. If safety has always been the company's top priority, then whenever in the past PG&E determined that moving to a best practice was necessary for safety, PG&E should have done so and requested funding for the best practice from the Commission.

Under oath in the 2012 Pipeline Safety Enhancement Plan (PSEP) evidentiary hearings, Thomas Bottorf, one of PG&E's highest ranking officers, candidly testified that, in his 30 years

[25] PU Code Section 963(b)(3).
[26] PG&E July 15, 2014 Supplemental Testimony, Appendix 1.

of being involved in ratemaking at PG&E, "it's generally true . . . that to the extent the company has sought ratepayer funding for safety improvements that the Commission has granted those requests."[27] Thus, according to PG&E, for the last 30 years, it has had a full opportunity to obtain ratepayer funding for any improvements, best practice or otherwise, that it believed was necessary for safety.

If safety has always been PG&E's highest priority and PG&E generally has been granted the ratepayer funding for safety that it requested, then SB 705 would not seem to be the revolutionary change agent that PG&E makes it out to be. What has really changed is that the San Bruno explosion and subsequent focus on PG&E's gas operations have shown that PG&E neglected its transmission system to the point that the system suffers from numerous safety deficiencies.

Thus, while the pressure test requirement of D.11-06-017 is a new requirement that has added cost to PG&E's operations, much of the remainder of PG&E's huge rate increase request cannot be justified by a change in laws. The real reason for much of the increase is that, in the wake of the San Bruno explosion and the spotlight it shined on PG&E's deficient operations, the scope and extent of PG&E's deficiencies became clear. Despite considerable remedial work from 2011-2104, PG&E still has a long way to go to rectify its deficiencies. As shown by the accompanying testimony of David Berger for TURN, remedying past non-compliance and imprudent practice is the primary purpose for much of the work PG&E proposes in this case.

IV. PG&E's Risk Assessment Methodology Frustrates the Targeting of Risk Mitigation Measures in the Most Cost-Effective Manner

In addition to the comments on PG&E's risk assessment approach in the accompanying Testimony of David Berger, TURN offers these comments.

[27] R.11-02-019, Transcript, vol. 9 (3/20/12), p. 959.

With respect to PG&E's scoring of candidate risk mitigation programs, the SED analysis points out some significant shortcomings in PG&E's approach. From TURN's perspective, the most significant problem is that PG&E is not able to rank candidate risk mitigation program by cost-effectiveness – that is, risk mitigation per dollar of expenditure. Similarly, when considering alternative means of mitigating a particular risk, PG&E cannot score and rank the alternatives based on the cost-effectiveness of the alternatives in reducing risk. Furthermore, when scoring one risk mitigation program, PG&E does not take into account the synergistic risk reduction benefits that a different risk mitigation program. An example of the latter problem, discussed in Mr. Berger's testimony, is PG&E's failure to consider the risk mitigation value of its Commission-mandated hydrotesting program in scoring the risk mitigation benefit of its Make Piggable program.[28]

All of these problems undermine the achievement of a key goal of the Commission's new risk assessment requirements, as summarized by Liberty Consulting in a quotation included in PG&E's direct testimony:

> That transparency will allow stakeholders to engage in a much more robust process of valuing the benefits of expenditures, both relative to alternatives for addressing safety risks, and relative to other risks and opportunities (e.g., reliability, customer satisfaction, and environmental stewardship) that must be balanced if vital public services are to continue to remain economically sustainable.[29]

V. PG&E's Shareholders Should Be Assigned Responsibility for the Costs of Much of the Remedial Work PG&E Proposes

Although PG&E attempts to mostly sidestep the issue, a key issue in this case is how the costs of the proposed work should be apportioned between ratepayers and shareholders. In this

[28] Berger Testimony, pp. 13-14.
[29] Liberty Consulting, Study of Risk Assessment and PG&E's GRC, May 6, 2013, p. 5, quoted in PG&E Direct Testimony, p. 1-11.

respect, PG&E is following the script it used in the PSEP case. There, PG&E proposed a $2.2 billion program, and in response to the Commission's directive that PG&E make a shareholder cost responsibility proposal, PG&E offered to have shareholders pay for only 10% of the program costs. PG&E's main theme for seeking to impose 90% of the costs on ratepayers was, as here, that the new work was made necessary by new regulatory requirements, and that PG&E had removed the costs of any compliance work from its request. The Commission disagreed with PG&E's view of the PSEP case in several key respects, ultimately limiting PG&E's cost recovery from ratepayers to $1.17 billion, with much of the reduction attributable to making shareholders responsible for costs resulting from PG&E's imprudence in operating its gas transmission system.[30]

The accompanying Testimony of David Berger shows that, as in PSEP, much of the work PG&E proposes here is necessary to rectify safety deficiencies, which again raises the key issue of the extent to which ratepayers should be paid to remedy PG&E's past mistakes and non-compliance. The remainder of this section discusses the cost responsibility principles that the Commission has followed and should continue to follow and then explains how those principles should be applied to PG&E's request.

A. It Is Well-Settled That Ratepayers Should Not Be Required to Pay for the Consequences of Utility Imprudence

As TURN will further demonstrate in its post-hearing briefs, a long-established corollary of the requirements of Public Utilities Code Sections 451 ("just and reasonable") and 454 (utilities must justify proposed rate changes) is that ratepayers should not be required to pay for costs that result from a utility's imprudence. The Commission has recently reaffirmed this

[30] D.12-12-030, p. E3, Table E-4.

principle in PG&E's PSEP decision, among other decisions.[31] TURN will further show in its briefs that, as part of a utility's burden to demonstrate the reasonableness of all aspects of its application, PG&E bears the burden of proving that the costs it seeks to recover are not the result of imprudence, i.e, that the costs are prudent.[32]

Failure to comply with a code requirement is obviously imprudent, but imprudence is not limited to adjudicated or conceded code violations. In the PSEP decision, the Commission made PG&E shareholders responsible for hydrotesting costs and remedial recordkeeping work made necessary by PG&E's imprudence, even though the Commission did not make any findings of particular code violations.[33]

Furthermore, the principle of requiring shareholders to absorb costs resulting from imprudence applies to both expenses and capital expenditures. For example, in the PSEP decision, the Commission made shareholders responsible for $116 million in costs for a capital program to improve PG&E's records systems[34] (100% of the proposed costs) on the grounds that PG&E "imprudently managed its gas system records such that extensive remedial work is now needed to correct past deficiencies."[35]

The Commission's deliberations regarding cost responsibility have also considered whether ratepayers are being asked to pay a second time for work that was previously funded by ratepayers. For example, in the PG&E PSEP decision, part of the rationale for requiring shareholders to pay for costs to hydrotest pipe segments installed after 1955 was that ratepayers

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[31] D.12-12-030, p. 122, Conclusion of Law 13.
[32] See, e.g., D.12-12-030, pp. 41-42.
[33] D.12-12-030, p. 97. As it turns out, if the Commission had waited for a final adjudication of the Recordkeeping OII (I.11-02-016) as of August 2014 (almost 2 years after the PSEP decision), the Commission still would not have a final adjudication of the issues in that case and thus would still not be able to resolve the PSEP cost responsibility issues.
[34] D.12-12-030, p. 22.
[35] D.12-12-030, p. 87.

were effectively being asked to pay for pressure testing a second time.[36] In so concluding, the Commission quite properly did not put the burden on ratepayer representatives to prove by specific reference to PG&E rate requests and Commission decisions that previous rates included costs of pressure testing. Instead, based on the evidence that pressure testing became an accepted industry standard in 1955, the Commission effectively presumed that PG&E's rates included an increment to pay for pressure testing, a presumption that PG&E did not rebut.[37]

TURN believes that the cost responsibility principles that the Commission has applied can be summarized as follows:

(1) As a general matter, PG&E may not recover costs from ratepayers unless PG&E can prove that the costs are prudently incurred, that is, are not the result of imprudent actions.

(2) Where the imprudence relates to work that is needed to comply with regulatory requirements, the Commission will conclusively presume that PG&E's past rates included the cost to comply with requirements.[38] [39]

(3) Where the imprudence relates to failure to adhere to accepted good practices (but not regulatory requirements), the Commission will presume that PG&E's past rates included the cost to operate its system prudently and safely. This is a rebuttable presumption.[40]

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[36] D.12-12-030, p. 60.

[37] D.1212-030, p. 60. In contrast, with respect to pipe replacement, it was obvious that the pipeline replacement was being done for the first time in PSEP and there was no issue of whether PG&E had previously been funded to do that work. As a result, the Commission limited the shareholder responsibility for pipe replacement costs to the imputed costs of hydrotesting, so that ratepayers would not receive a new pipeline at no cost.

[38] The Commission has applied this principle in requiring shareholders to pay for any hydrotesting costs for segments installed after GO 112 went into effect in 1961. In so doing, the Commission has not inquired into whether rates included an increment to cover such hydrotesting costs.

[39] At least to some extent, PG&E has adhered to this principle in its rate request. PG&E says it has excluded from its request $21 million of capital costs and $58 million of expense for work that it concedes is "remediation in conjunction with non-compliance issues." In its explanation of this acceptance of shareholder responsibility, PG&E does not state that it considered whether ratepayers had funded this type of work in the past. (PG&E response to TURN 26-3.a).

[40] This is the approach the Commission followed with respect to pre-1961 hydrotesting costs in D.12-12-030 (p. 59).

(3) To escape shareholder responsibility in the case of the rebuttable presumption, the utility must show with convincing evidence – such as by specific reference to past rate requests and decisions -- that it has not previously sought or obtained rate recovery for work, that, if done properly, would mitigate the need for the proposed new work.[41]

Shareholder cost responsibility, sometimes called "disallowances" in Commission decisions, should be distinguished from reductions to utility forecast costs. Examples of the latter are findings that: proposed costs for the activity are too high (e.g., excessive unit costs); the proposed pace of the work should be slowed down, resulting in reduced cost in the rate case period; and the scope of the proposed work is not necessary or cost-effective and should be reduced. Thus, in some instances, depending on the rationale, a reduction to a utility's forecast can be an indication that the utility can reduce the scope of the proposed work effort in the rate case period.[42]

In contrast, when shareholders are assigned cost responsibility, the utility should be required to do the work, but shareholders should pay for it. Since, by definition, work that shareholders are obliged to fund is designed to remediate past imprudence, it is almost always important work that needs to be in a timely and complete fashion. Accordingly, with respect to activities that the Commission orders PG&E shareholders to fund in this case, the Commission should make clear in its decision the work that the utility is expected to perform and adopt safeguards to ensure that the work is actually done and that shareholders actually absorb the costs. One approach that the Commission adopted in the PG&E PSEP decision (e.g. with respect

[41] For example, in the PSEP decision, regarding PG&E's requests to recover new recordkeeping costs, the Commission presumed that ratepayers had paid for past recordkeeping functions and that, if PG&E had done that work properly, the new work would not be needed. PG&E did not rebut this presumption and PG&E shareholders were required to pay for all of the new recordkeeping costs, including a $115 million capital program. (D.12-12-030, p. 87).

[42] That said, inherent in forecast ratemaking is the obligation of the utility to carry out the necessary work to meet its regulatory responsibilities.

to hydrotesting and replacement) is to specify the work to be performed (e.g., number of miles of pipe to be addressed), state the cost cap for ratepayer recovery (which takes into account the shareholder contribution to the costs), and require follow-up reporting to make sure the work is done. An alternative to a cost cap that may make sense for certain capital disallowances is for the Commission to specify the percentage of costs to be assigned to shareholders.

B. PG&E Should Not Be Allowed to Escape Shareholder Responsibility for the Costs to Hydrotest Pipeline Segments Installed Between January 1, 1956 and July 1, 1961

D.12-12-030 explicitly determined that PG&E shareholders should be responsible for the costs to hydrotest (per D.11-06-017) pipe segments installed beginning January 1, 1956, when the 1955 ASME standards became the prevailing industry standard with respect to pressure testing and record retention. Nevertheless, even though it did not seek rehearing of this determination, PG&E argues for a change in the decision to allow shareholders to escape responsibility for segments installed from January 1, 1956 to December 31, 1961.[43]

TURN strongly opposes PG&E's request and will present its full arguments in its post-hearing briefs. For now, TURN makes the following points:

(1) D.12-12-030 already rejects PG&E's arguments (1) – (3) and (5) on page 4A-43. The Commission recognized that the ASME standards were voluntary (in the sense of not capable of fining operators for non-compliance), but found based on the record evidence that PG&E's practice was to comply with those standards.[44] The Commission stated:

> As it was PG&E's practice to incur these pre-service test costs, we would expect that absent unusual circumstances such costs would be included in revenue requirement and recovered from ratepayers. <u>No</u>

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[43] PG&E Direct, pp. 4A-42 to 4A-43.
[44] D.12-12-030, p. 59.

evidence has been presented to suggest that the cost of the 1956 to 1961 testing was excluded from revenue requirement.[45]

PG&E has not presented any different evidence showing that it did not attempt to comply with the ASME pressure testing standards, nor has it presented any evidence to show that pressure testing was not funded in its 1956 to 1961 revenue requirement.[46]

(2) In response to PG&E's argument (4) on p. 4A-43, while the ASME code may not have required hydrostatic testing of pipe segments operating below 30 percent SMYS, it did require a pressure test that could use water, air or gas as the test medium.[47] PG&E has not provided any evidence that a pressure test using air or gas is less reliable or useful than one that uses water. In the judgment of TURN's expert, David Berger, any of the three test media can validly serve the purpose of the pressure test.[48] In fact, the Subpart J standards still allow air or gas to be used for pressure tests, even for pipeline to be operated above 30 percent SMYS.[49]

Consequently, as required by D.12-12-030, PG&E shareholders should be required to pay for all hydrotest costs for any pipe segment that was installed on or after January 1, 1956. In response to a TURN data request,[50] PG&E "updated" Table 4A-12 as follows:

[45] D.12-12-030, p. 59 (emphasis added).
[46] PG&E's supposition that such rate recovery was "unlikely" does not constitute the evidence the Commission properly required, consistent with the cost responsibility principles
[47] ASME B.31.1.8-1955, Section 841.42.
[48] Mr. Berger's prepared written testimony was already complete at the time of preparing this testimony. However, he can testify to this point at the evidentiary hearing.
[49] 49 CFR Sections 192.503(b), 192.505.
[50] PG&E response to TURN 30-2. TURN requested PG&E to change the time periods in the second and third lines of the table to reflect the fact that GO 112 went into effect on July 1, 1961, not December 31, 1961 as the table in PG&E's direct testimony appears to assume.

Table 4
Untested Pipe By Installation Period

	Miles	Percentage
Pre-1956 or IM tests	315	61.8%
Jan 1, 1956 – June 30, 1961	98	19.2%
July 1, 1961 - Present	97	19.0%
Totals	**510**	100%

Based on Table 4, PG&E's shareholders should be responsible for the full costs of hydrotesting the 38.2% of pipe segments that were installed between January 1, 1956 and June 30, 1961. To ensure that shareholders pay their full and fair share of these costs, the Commission should, as it did in D.12-12-030, specify the total number miles of pipe that PG&E is required to test in the rate case period, and provide a ratepayer cost cap for this work based on the approved cost to perform this work minus the cost to test the 38.2% of segments for which shareholders are responsible.[51]

In addition, the Commission should impose a commensurate disallowance of PG&E's proposed capital costs associated with hydrotesting. For example, if the Commission requires shareholders to pay for 38.2% of the costs of the hydrotesting program in this rate case period, then the same percentage of capital costs should be disallowed from rate recovery. PG&E's description of the need for this capital work shows that the amount of the capital costs is directly related to the number of pipelines that are hydrotested. The disallowance is necessary to reflect the fact that, but for PG&E's imprudence, a significantly reduced percentage of pipeline would need to be tested.

[51] TURN's use of the 38.2% figure in this paragraph should not be construed as TURN confirmation that this PG&E-supplied percentage is accurate. To date, TURN has not had the time or resources to test the accuracy of this percentage.

Finally, the Commission should reject PG&E's "plan" to add mileage from its "flex list" to reach 170 miles per year of recoverable testing mileage.[52] This statement appears to mean that, if the Commission were to require shareholders to pay for hydrotesting of 195 miles of January 1, 1956 – June 30, 1961 pipeline per Table 4 above, then PG&E would hydrotest an additional 195 miles in the rate case period, for a total of 705 miles – all for the purpose of allowing PG&E to get rate recovery for 510 miles. As discussed in Section 4 of the accompanying testimony of David Berger, there are significant questions whether PG&E can effectively and efficiently accomplish the work it has specifically proposed in its request. To add significant additional mileage to its hydrotest program does not seem feasible. PG&E concedes as much when it states that it elected to continue with the 170 mile per year PSEP pace because "attempting to strength test more miles than this, combined with other high priority work planned for this period, will strain resources and could impact the system's ability to serve customers due to the lengthy outages needed for strength tests."[53]

C. Shareholders Should Bear Cost Responsibility for a Significant Portion of the Costs of Many Other Proposed Programs

The accompanying testimony of TURN's gas transmission infrastructure and safety expert, David Berger, shows that there are several programs for which PG&E is now attempting to remedy past imprudence. These programs include (along with reference to the applicable section of Mr. Berger's testimony):

- Integrity Management assessments using In-Line Inspection (ILI) and Direct Assessment (DA) (Section 5.1)
- Shallow pipe program (Section 5.6)

[52] PG&E Direct, p. 4A-42.
[53] PG&E Direct, p. 4A-36.

- Measurement and Control: Engineering Critical Assessment (ECA) Phases 1 and 2 and hydrotesting (Section 5.8)
- External corrosion control (Section 5.9.1)
    - New cathodic protection (CP) systems
    - Corrosion investigations
    - Electrical interference (AC and DC)
    - Casings
- Internal corrosion control (Section 5.9.2)
- Atmospheric corrosion control (Section 5.9.3)
- Transmission expense projects (Section 5.10)
- Net operating pressure (NOP) reductions (Section 5.11)

In most of these programs, much or all of the proposed work is needed to address problems that should have been corrected earlier in order to comply with regulatory requirements. PG&E's prior efforts to ensure compliance were inadequate and/or ineffective. Put another way, PG&E was being funded to operate and maintain its transmission system to at least satisfy the minimum regulatory expectations. PG&E did not get the job done, necessitating significant remedial work in this rate case period.

A typical example is the external corrosion – casings program. As Mr. Berger explains, it has been a requirement of the federal regulations since 1970 that pipelines be electrically isolated from metallic casings. PG&E states that it has identified 335 of its approximately 3,200 casings that are contacted and need mitigation. These contacted casings did not just suddenly occur, but constitute a backlog that PG&E has failed to effectively correct. Of the 98 capital projects to mitigate contacted casings, PG&E admits that only 4 of them are to address mitigations that are expected to be required based on routine annual testing. Similarly, of the 117 expense projects, only 6 fall in the routine category.[54] To comply with applicable regulations, PG&E could and should have previously mitigated the backlogged contacted casings. PG&E's rates funded PG&E's work to comply with these and other regulations, yet PG&E failed to do so with respect to contacted casings. Although, as discussed below, TURN is not making a final shareholder recommendation on this and other programs at this time, TURN anticipates recommending that shareholders be held responsible for most of these costs to rectify PG&E's imprudent failure to mitigate contacted casings.

TURN is not making specific recommendations of the programs and amounts for which shareholders should be assigned cost responsibility at this time. Based on the testimony submitted by ORA[55] and other parties, as well as the evidentiary hearing record, TURN will provide specific recommendations in its opening brief.

V. PG&E's Supplemental Testimony Fails To Establish The Reasonableness Of The Utility's 2011-14 Capital Expenditures

PG&E's application asks the Commission to permit the utility to "roll into rate base" its 2011-2014 capital expenditures.[56] TURN's protest questioned the sufficiency of the utility's showing in support of the reasonableness of the capital expenditures recorded for 2011 and 2012, and forecasted for 2013 and 2014.[57]

In supplemental testimony served March 7, 2014, PG&E sought to support "the nearly $700 million in actual and forecast capital expenditures for 2011-2014 above what was adopted

[54] Berger Testimony, p. 22.
[55] Ordinarily in a rate case of this magnitude, TURN and other intervenors would have a few weeks to review ORA's testimony before submitting their testimony.
[56] PG&E Application, p. 26.
[57] TURN Protest, pp. 6-9.

by the [Commission] in Decision 11-04-031."[58] It did so by providing "detailed information on a large and representative sample of projects and programs" that represented nearly $500 million of the $700 million above the amounts embedded in the Gas Accord V settlement.[59] The supposedly "detailed information" for this $500 million of spending appeared in six pages of text and a sixteen-page spreadsheet that includes a "Description of Capital Expenditure" for each of the 104 projects included in PG&E's sample.

A. PG&E's General Approach Fails to Justify Large Portions Of The 2011-14 Capital Expenditures

PG&E's supplemental testimony is structured in a manner that avoids addressing, much less establishing, the reasonableness of PG&E's proposed capital expenditures for the 2011-14 period.

First, PG&E's starting point is $698,400,000 of "Capital Expenditures Above Adopted Amounts." PG&E has implicitly assumed that the spending and projects covered by the "adopted amounts" used as the baseline for this characterization should be presumed reasonable. TURN submits this is a questionable assumption under the circumstances. The projects and cost estimates underlying PG&E's 2011 GT&S application reflected 2009 forecasts of 2011-2014 activities. After the September 9, 2010 San Bruno catastrophe, it is likely that for at least some of the projects and programs with forecasts included in the "adopted amounts," PG&E chose not to pursue the project due to changed priorities. There is also the concern that projects or costs that should be deemed part of the PSEP-related efforts (and subject to PSEP-related rate recovery restrictions) are instead designated as GT&S projects. Under these circumstances, there is reason to review the entirety of PG&E's GT&S spending during 2011-14, whether or not the reported amount is part of the "adopted amounts" from the 2011 GT&S decision. PG&E's direct showing

[58] PG&E Supplement to Chapter 3 Forecast Summary ("Supplemental Testimony"), p. 3S-1.
[59] *Id.*

does not permit any such review for whatever projects PG&E deemed covered by the "adopted amounts."

Second, PG&E only purports to address $617,529,000 of the amount it calculated as "Capital Expenditures Above Adopted Amounts."[60] In other words, $80,871,000 of the "Capital Expenditures Above Adopted Amounts" is not addressed anywhere in PG&E's Supplemental Testimony. PG&E explains that it selected only projects or programs that were originally forecast in the 2011 GT&S Rate Case but exceeded or are forecast to exceed the forecast by $1 million or more, and projects and programs that were not originally in the 2011 GT&S Rate Case and have forecast costs in excess of $1 million.[61] PG&E does not explain why it selected these criteria for inclusion in its supplemental testimony.[62] Whatever the explanation, the result is that by PG&E's admission it has presented no showing of any kind in support of $80,871,000 of spending.

Third, PG&E claims capital expenditures for four "programs" – Tools and Equipment, Buildings, Pipeline Reliability/Safety, and Corrosion – will be above the 2011 GT&S adopted figures by a total amount of $118,639,000.[63] PG&E correctly calculates this amount to be "almost 20 percent of the expenditures above Gas Accord V adopted expenditures."[64] The utility provides a very summary description of these programs. There is one sentence that addresses "Buildings" and "Tools and Equipment" together, describing them as "largely expenditures associated with equipping and supporting a larger work force." A second sentence addresses "Corrosion" and "Pipeline Reliability/Safety" together, describing them as "generally a mix of

[60] Table 3-1 (Supplemental), p. 3S-4.
[61] Supplemental Testimony, p. 3S-3.
[62] The $1 million figure for projects or programs not included in the 2011 GT&S forecast seems particularly inappropriate, given that the Gas Transmission and Safety Report required under D.11-04-031 employs a project-specific reporting cut-off of $250,000. D.11-04-031, Appendix C.
[63] Supplemental Testimony, Table 3-1 (Supplemental), p. 3S-4.
[64] *Id.*, p. 3S-5.

projects to monitor and mitigate the threat of external corrosion, and to maintain pipeline integrity through pipe replacement."

PG&E then provides a slightly lengthier discussion of the "Buildings" program, stating that its projected actual total expenditure for 2011-14 is approximately $36.2 million above the amount included in Gas Accord V for this program, and claiming the additional expenditures were primarily driven by the Gas Operations headquarters office in San Ramon, a new gas training center building, and "additional yards and offices to support increased execution work in the field."[65] PG&E does not present the amounts it would attribute to each of the cited primary drivers. Assuming the utility's capital expenditures for the Gas Operations headquarters and gas training center building are the same in total and in the amount attributed to transmission operations as the utility presented in PG&E's test year 2014 GRC, those two projects would appear to explain approximately $14.5 million of the $36.2 million figure PG&E reports here.[66] So the generic "additional yards and offices" appear to be $21.7 million of the PG&E total for this program.

There is no similar discussion of the amounts or the primary drivers for the Tools and Equipment, Corrosion, or Pipeline Reliability/Safety programs.

In sum, for the $118,639,000 of 2011-14 spending on these four programs, there is nothing in the Supplemental Testimony or Attachment A that supports the amounts tied to three of the programs. For the Buildings Program, PG&E includes a paragraph identifying three primary

[65] Supplemental Testimony, pp. 3S-5 to 3S-6.

[66] In A.12-11-009 (PG&E's 2014 test year GRC), the utility forecast capital expenditures totaling $22.546 million for 2011-14 for its Gas Operations Headquarters building, and $52.74 million for its Gas Training Center (WP PG&E-3, Ch. 7-12, pp. WP 12-25 and WP 12-6), and allocated 81.65% of those costs to distribution operations. The remainder (19.35%) was allocated to transmission operations, and would total $14.5 million. of $22.546 million is $4.36 million.

drivers, but no explanation of the amounts attributable to each driver or any detail on the generic "additional yards and offices" that seems to explain $21.7 million of PG&E's figure.

B. PG&E's Supplemental Testimony Fails To Establish The Reasonableness Of The 104 Projects From 2011-14 That The Utility Chose To Include

PG&E claims that its supplemental testimony provides "detailed information on a large and representative sample of projects and programs."[67] TURN does not dispute that PG&E's supplemental testimony included more information on these projects and programs than did its application or the direct testimony served therewith. However, the question for the Commission is whether PG&E's supplemental testimony establishes the reasonableness of PG&E's capital expenditures in 2011-14 sufficiently to permit rate recovery. TURN submits that it does not.

As a general matter, PG&E's showing is deficient in two ways. First, the utility does not provide a sufficient demonstration of the reasonableness of each of the projects. The supplemental testimony suggests that, in PG&E's view, it is enough to label these projects as "respond[ing] to the call for safety first and the adoption of industry best practices. As such, they benefit our customers and are appropriate to include in rate base."68 A label of "safety" or "best practices" is not enough to establish reasonableness for a specific project or program.69 Second, even if the Commission were to presume that each project or program is reasonable in design, PG&E has not demonstrated that the associated funding level, whether the amount listed in the original job estimate or other similar materials in the workpapers, or the amount included in its Attachment A, is a reasonable figure for the job in question.

[67] Supplemental Testimony, p. 3S-1.
[68] Supplemental Testimony, p. 3S-2.
[69] The Commission appears poised to affirm this point in the PG&E 2014 test year GRC. "In evaluating PG&E's cost claims, we require that unless a work activity or program is mandated, the utility must demonstrate that the overall benefits justify the costs imposed on ratepayers…. It is not enough to merely assert that safety would be compromised absent approval of a particular work effort." Revised PD in A.12-11-009, p. 26.

1. The Example Projects Cited In PG&E's Supplemental Testimony Highlight Shortcomings Of The Utility's Showing on 2011-14 Projects.

PG&E describes an approach that included separating projects or programs originally included in the 2011 GT&S Rate Case from those that were not.[70] It then describes an example of a "representative project" from each of these categories.

For the category of projects that had appeared in the 2011 GT&S Rate Case, PG&E selected the McDonald Island Whiskey Slough Station Rebuild. In the 2011 GT&S PG&E had forecast two separate projects to complete partial rebuilds of the Whiskey Slough station. According to PG&E, a condition-based assessment performed in early 2011 identified a number of risks that led PG&E to decide to rebuild the entire station. PG&E calculates $53.4 million as the "total expenditures above adopted amounts" from the 2011 GT&S.[71]

This is quite a shift in a short period of time. In the course of developing its 2011 GT&S application and supporting testimony, PG&E performed an assessment of the projects necessary for the utility to continue providing safe and reliable service. According to the testimony and workpapers supporting the 2011 application, the utility's initial assessment concluded that two projects rebuilding a portion of the Whiskey Slough station at an expected cost of $8 million would suffice.[72] But based on the condition-based assessment performed in early 2011, the utility determined that the entire station needed to be rebuilt in two stages at an expected total cost of $65.8 million.[73] PG&E's workpapers provide high level cost estimates that add up to that amount, but never explain why the Commission should find reasonable the recorded spending

[70] Supplemental Testimony, p. 3S-3.
[71] Supplemental Testimony, p. 3S-4.
[72] 2011 GT&S PG&E Updated Workpapers for Chapter 6, p. WP 6-6, lines 186-187.
[73] Supplemental Workpapers Supporting Chapter 6, p. SWP 6-175. According to the Business Case for the project, the "cost estimate rigor" for this project was below the level that would warrant the label "Detailed bottoms-up estimate completed," but above "estimates based on 'rule of thumb' or high-level benchmarks." *Id.*, at SWP 6-205.

figure that, by the utility's calculations, produced an increase of $53.35 million for the expanded project.[74]

In addition, PG&E's calculation of the 2011 GT&S forecast attributable to this project is incorrect, resulting in an inflated figure for the incremental costs. As PG&E's supplemental testimony noted, PG&E's 2011 GT&S forecast had included two separate Whiskey Slough projects. Each of those projects had a forecasted capital expenditure of $4 million (or $8 million total).[75] But in PG&E's calculations in Attachment A to the Supplemental Testimony, the utility only cites one of those projects and calculates the amount from the GT&S settlement as $2.733 million, a downward adjustment from the project's original $4 million estimate.[76] Even if that calculation were correct for a single Station Reliability project with a $4 million estimate, PG&E's offset for the amount from the 2011 GT&S Settlement should have been double that figure.[77]

For the category of projects that had <u>not</u> been included in the 2011 GT&S, PG&E provides two examples. The first is a main line valve installation on Line 108, where PG&E states that the existing valve was insufficient to address local area growth and made it such that a key distribution feeder main could not provide gas to the community.[78] PG&E describes the project as representing $5 million in total expenditures. But the Job Estimate PG&E provides in

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[74] Supplemental Testimony, Attachment A, Line 60.
[75] 2011 GT&S PG&E Updated Workpapers for Chapter 6, p. WP 6-6, lines 186-187.
[76] PG&E does not set forth the specific calculation of the $2.733 million figure as the amount from the GT&S 2011 settlement. Its supplemental testimony includes a footnote with a sentence generally describing a prorating that occurred to calculate a "settled" cost from the PG&E forecast. Supplemental Testimony, p. 3S-3, fn. 6.
[77] If nothing else, PG&E should reduce the amount it is claiming for 2011-14 by $2.7 million to reflect the fact that there were two projects, not one, in its 2011 GT&S proposal for the Whiskey Slough Station.
[78] Supplemental Testimony, pp. 3S-4 to 3S-5. The growing community appears to be Elk Grove. *Id.*, Attachment A, Line 99, referring to "rapid growth in the Elk Grove area." The "rapid growth" presumably occurred between the 2008-2009 period, when PG&E would have been assessing its needs for purposes of assembling its 2011 GT&S application, and November 2010, when the project was first approved at PG&E. Supplemental Testimony Workpapers, p. SWP 10-116.

its workpapers forecast expenditures of $2.2 million.[79] Attachment A includes a single sentence that identifies several factors that contributed to the rise in project costs, but does not attempt to address the degree to which any of the factors explain some or all of the 133% increase.[80]

The examples provided by PG&E reflect some of the general problems and concerns that TURN believes prevent the Commission from finding reasonable the requested capital expenditures for 2011-14. In the following section, TURN will identify and discuss a number of those general problems and concerns.

2. PG&E Offers Inadequate "Support" For the 104 Projects It Chose To Include In Its 2011-14 Showing.

As noted above, PG&E's Supplemental Testimony specifies 104 projects representing a portion of the 2011-14 capital expenditures that exceed the amount authorized for that period in D.11-04-031. For nearly every one of those projects, PG&E's Supplemental Testimony and Workpapers are inadequate to support a determination of the reasonableness of need for the project, the requested level of expenditures, or both.

The "support" provided for nearly every project is some combination of PG&E's original Job Estimate and various Business Cases, "Advance Authorizations" and "Request for Additional Funding." Typically the documents contain general assertions about the need for the project, without the kind of detail one would expect for projects expected to cost at least $1 million each, especially when proposed by a utility that has to know it is facing closer-than-usual scrutiny in the area of gas infrastructure spending.

[79] Supplemental Testimony Workpapers pp. SWP 10-116 and 10-127.
[80] Supplemental Testimony, Attachment A, Line 99.

3. PG&E Offers Cost Information That is Suspect.

The supporting materials to PG&E's Supplemental Testimony include a number of cost figures for each project. Attachment A (the table listing each of the 104 included projects) shows the amount included in the 2015 GT&S rate case and, where relevant, an estimate of the project funding authorized when the Commission adopted the proposed settlement in the 2011 GT&S. The workpapers to the supplemental testimony present different cost estimates apparently developed during PG&E's internal review of each project. The cost in PG&E's Attachment A is only very rarely the same as the cost estimate in the workpapers for the same project. In some cases the amount PG&E seeks to include in rate base (from Attachment A) is greater than its own internal estimates (from the workpapers); in others it is lower.

An example of a project for which the Attachment A figure is far higher than PG&E's own estimates is the proposal to replace 3,431 feet of 30-inch pipe on L-132.[81] PG&E's workpapers include a December 2012 "Advance Authorization" with an estimated cost of $9.569 million for this project.[82] In Attachment A, PG&E indicates $22.787 million of capital expenditures for the same project. There is no discussion of the more than doubling of the forecasted cost that has occurred since the end of 2012.

In some cases, PG&E's documentation shows a significant increase to the forecasted cost while the project was under development at the utility, with inadequate explanation of the drivers of that increase. PG&E's proposed rebuilding of the Lomita Park Station saw the cost estimate double (from $3.5 million to $7.4 million) between April 2012 and October 2013.[83] The utility now seeks $11.7 million for this project;[84] the increase from $7.4 million to $11.7 million is also

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[81] Line 18 of Attachment A.
[82] Supplemental Testimony Workpapers pp. SWP 4A-270.
[83] *Id.*, pp. SWP 6A-465, 6A-476.
[84] Attachment A, Line 81 (Rebuild Lomita Park Station).

inadequately explained. And the "Delevan Cost Escalation" document addressing work at the Delevan Compressor Station indicates a doubling in the expected cost for the project since the initial conceptual estimate from 2006.[85]

PG&E's cost figures include a calculation of an amount it would attribute to certain projects from the 2011 GT&S authorized capital spending. As noted above, for the Whiskey Slough Station rebuild, PG&E correctly refers to two related projects in the 2011 GT&S, but calculates the offset ($2.7 million) based on only one related project.

Finally, for the Healy Station Launcher project with a $3.2 million cost included in PG&E's request, the utility opted to provide no supporting documentation at all.[86]

4. The Material PG&E Has Provided Raises Troubling Questions That PG&E Has Not Adequately Addressed.

For many of the 2011-14 capital expenditures PG&E includes in its Supplemental Testimony and supporting materials, there are elements that suggest serious questions about the appropriateness of permitting rate recovery in this proceeding.

a) Potential PSEP Overlap.

PG&E claims that its Supplemental Testimony does not include Pipeline Safety Enhancement Plan (PSEP) capital expenditures in excess of the amounts adopted in D.12-12-030.[87] However some of the abbreviated descriptions that appear in Attachment A and the workpapers raise questions about whether PG&E excluded all such costs.

For example, PG&E includes a pipeline installation for which the job summary from November 2012 very plainly states that it is "Replacement 206" from the "Pipeline Safety

[85] Supplemental Workpapers, p. SWP 6-113.
[86] Attachment A, Line 22 (Healy Station Launcher).
[87] Supplemental Testimony, p. 3S-1, fn. 2.

Enhancement Plan (Integrity Management)." The description goes on to state, "As part of the Pipeline Safety Enhancement Plan this job proposes to …."[88] Based on PG&E's showing, the Commission could reasonably conclude that this is a PSEP project, not a GT&S project.

Additionally, the pipe replacement project that PG&E labeled DFM-7221-15 Repl 1.61Mi MP 0.04-1.69 Ph1 was initially designated a PSEP project and included in the PSEP application.[89] The job estimate from August 2012 states, "The PSEP team will manage and execute the work."[90] The Business Case further explains that the project was included in both the 2011 GT&S rate case and the PSEP rate case. When PG&E realized the duplication, it opted to treat the project as a GT&S project rather than a PSEP project.[91] The forecast from the 2011 GT&S testimony was $2.034 million, but PG&E has included $9.283 million as the project cost for the 2015 GT&S request.[92] Had PG&E left this as a PSEP project, the rate recovery prospects for the $7 million of costs above the original forecast would likely be more limited than if the project is treated as a GT&S project.

b) Projects necessary to meet requirements or address needs that pre-dated the 2011 GT&S application that have been in place for years

PG&E suggests that its capital expenditures in 2011-14 that "far exceed the work envisioned at the time the 2011 rate case was filed and settled" are attributable in substantial part to "changes in expectations and requirements."[93] But for many of the projects, the underlying expectations and requirements pre-dated the 2011 GT&S application.

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[88] Attachment A, Line 27; Supplemental Workpapers, p. SWP 4A-352.
[89] Supplemental Testimony, Attachment A, Line 96.
[90] Supplemental Workpapers, p. SWP 10-91.
[91] *Id.*, SWP 10-97.
[92] Supplemental Workpapers, p. SWP 10-98, Supplemental Testimony, Attachment A, Line 96.
[93] Supplemental Testimony, p. 3S-2.

For several projects, PG&E cites the work as necessary to comply with 49 CFR Part 192. But the federal regulations, including Subpart O, predate the 2011 GT&S application. If PG&E was not on a path to achieve compliance with 49 CFR Part 192 or other regulatory or statutory standards as they existed when the utility filed its 2011 GT&S application, that is a separate matter from any "changes in expectations and requirements."

For a number of projects, PG&E cites the need to address a "class change," that is, the area surrounding a section of pipe had developed in such a way that it was no longer a Class 1 or Class 2 segment, but qualified as a Class 3 segment based on a 2011 study.[94] But in one case the change appears to have been identified by a class location study from 2006.[95] And in another, PG&E's materials note that a nearby section of pipe had been replaced earlier, due to the change to a class 3 designation.[96] As a general matter, TURN questions the reasonableness of an approach that suggests that a change in class designation is the type of event that would catch a well-functioning utility by surprise, particularly where it knows or should know that a nearby pipe segment was changed out due at least in part to this reason.

In one instance, PG&E presented a very candid self-evaluation. The need for a security upgrade at one of its stations is explained as the product of a failure to perform required periodic inspections, and systems that had fallen into disrepair due in part to a failure to include in district budgets the funds necessary to support maintenance of the systems.[97] In TURN's view, the Commission should be concerned that PG&E's self-critique applies with equal force to many of the 2011-14 projects.

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[94] Supplemental Testimony, Attachment A, Lines 32-40.
[95] *Id.*, Line 33.
[96] *Id.*, Line 35.
[97] Supplemental Workpapers, p. SWP 6-336.

c) Projects That Raise Questions About Factors Driving Up Costs And Higher-Than-Usual Unit Costs

For a number of PG&E's 2011-14 projects, the utility-presented information notes that the project-specific costs were high. For example, the "description" of the first project in Attachment A (an ILI upgrade to L-108) notes, "The costs for this work increased because contract costs were higher than anticipated and identifying final work site locations took longer than anticipated."[98] There is no additional information from PG&E that addresses the reasonableness of the higher than anticipated costs (or even the reasonableness of the anticipated costs).

In other cases, PG&E noted significantly higher unit costs (an estimated cost per foot of $1,757 where the recorded figures ranged from $175 to $542 per foot);[99] and an increase in costs because PG&E relied on contract engineering and procurement services and construction service, rather than its in-house resources.[100]

For one job, PG&E booked overtime and doubletime costs because it was a "high profile project being watched by many groups and the media" that ran into a "time crunch."[101] On another PG&E sought approval of additional funding because of the numerous delays in completing the project due to moving crews or equipment off the job in order to complete other critical jobs on numerous occasions.[102]

As noted in Mr. Berger's testimony,[103] much of PG&E's work in the 2011-2013 period was of a rushed, emergency nature, brought about by the need to remedy serious deficiencies

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[98] Attachment A, Line 1.
[99] Supplemental Workpapers, p. SWP 4A-310. PG&E's documents describe this unit cost as "higher than anything on the comparison list."
[100] *Id.*, p. SWP 6-182. PG&E's documents for the Whiskey Slough Station rebuild calculates the cost impact from these factors as $7.7 million.
[101] *Id.*, p. SWP 4B-147.
[102] *Id.*, p. SWP 10-5 and 10-7.
[103] Berger Testimony, p. 15 and fn. 17.

exposed by the San Bruno explosion and resulting investigations. For reasons explained above, it is not reasonable to require ratepayers to pay for these escalated costs resulting from PG&E's imprudence.

C. Conclusions and Recommendations

PG&E's Supplemental Testimony indicates the utility expects to make $700 million of capital expenditures above and beyond the amounts forecasted in the 2011 case. The Supplemental Testimony and supporting workpapers address approximately $500 million of that spending. The materials identify the 104 projects and, for most of them, set forth the utility's initial cost forecasts and either the recorded cost figure (for projects completed in 2011-12) or a more recent forecast (for 2013 and 2014 projects). The word "reasonable" appears nowhere in the Supplemental Testimony. Instead, PG&E summarizes its approach as follows:

> These actual and forecast capital investment respond to the call for safety first and the adoption of industry best practices. As such, they benefit our customers and are appropriate to include in rate base.[104]

PG&E's approach seems to be that if the utility affixes a "safety" or "best practices" label on a project, no showing of reasonableness of the project's cost is required. This is incorrect. As noted earlier, the Commission seems poised to adopt a 2014 test year GRC decision for PG&E that reaffirms the inappropriateness of such an approach.

At this time, TURN recommends the following with regard to PG&E's 2011-2014 capital expenditures:

1. The Commission should disallow rate recovery of capital expenditures for which the utility did not present any material regarding the reasonableness of the expenditures. This would include the approximately $81 million of 2011-14 "Capital Expenditures Above Adopted Amounts" that PG&E chose not to include in its supplemental testimony, the $118.639 million[105] of expenditures for

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[104] Supplemental Testimony, p. 3S-2.

[105] The PG&E 2014 test year GRC decision may authorize spending for the Gas Operations Headquarters and Gas Training Center projects, but in different amounts and with different allocations between distribution and

"programs" that were mentioned but not addressed in any meaningful way in that testimony, and the $3.2 million cost of the project for which PG&E chose to include no supporting documentation.

2. A third party audit should be conducted to ensure that all 2011-14 capital expenditures associated are properly treated as GT&S expenditures and reasonable for recovery in rates. This would include, at a minimum: (a) reviewing PG&E's assignment of costs to GT&S-related projects rather than PSEP-related activities during that period; (b) determining the extent to which PG&E's costs were inflated by the emergency nature of PG&E's gas transmission system remediation work in this time period; and (c) determining the extent to which expenditures were made to remediate imprudence. In light of PG&E's poor showing to date, PG&E should be directed to fund the audit at shareholder expense.

3. PG&E should not be permitted cost recovery of any portion of the 2011-14 capital expenditures in excess of the amounts set forth in the 2011 GT&S settlement until the Commission has issued a decision setting forth its review of the third party audit. This should give PG&E additional incentive to fully cooperate with the audit.

VI. The Commission Should Consider Other Ratemaking Adjustments

In addition to assigning cost responsibility to shareholders in appropriate cases, the Commission has other ratemaking options that can address to some extent the fact that much of PG&E's request is designed to remedy longstanding deficiencies in its transmission system. These include the following:

Amortizing expense recovery over an extended period. As shown in Mr. Berger's testimony, for many programs, PG&E's 2015 expense forecasts are inflated by the fact that much of PG&E's propose work is of a catch-up nature. Expenses that are not assigned to shareholders can be amortized over an extended period, 10 years or longer, in recognition of this fact. Shareholders should be made responsible for the carrying charges for this amortization. The Commission should also make clear that it expects PG&E's 2015 GT&S proposal to be an

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transmission than those PG&E proposed. Therefore an adjustment to this figure may be warranted once a final decision issues.

aberration that does not create a "new normal" and that, once the system's deficiencies are addressed in this rate case cycle, PG&E should have more modest funding requests for its transmission system.

Reducing PG&E's rate of return on capital assets. In a competitive sector of the economy, a company that mismanaged its operations as much as PG&E would be fortunate to survive, let alone continue to earn a profit. PG&E should not be allowed to earn a full return on capital spending that is designed to remediate ineffective efforts in the past. TURN will make a specific proposal for a rate of return reduction in its opening brief.

Slowing the pace of capital expenditures. As discussed in the Berger testimony, for certain programs, PG&E has failed to justify the need to adopt the accelerated capital spending plan PG&E proposes. Mr. Berger identifies the "Make Piggable" program (Section 5.2), the Earthquake Fault Crossings program (Section 5.3), and the Water and Levee program (Section 5.5) as falling in this category.

VII. The Commission Should Limit this Rate Case to a Two-Year Period and Address GT&S Revenue Requirements in the Next GRC

As in the Rate Case Plan Rulemaking (R.13-11-006), TURN here recommends that the cycle for the revenue requirements adopted in this case be limited to two years, not three years as PG&E proposes. This would allow GT&S revenue requirements to be determined in the next PG&E GRC (2017 test year), where the revenue requirements for all of PG&E's other CPUC jurisdictional operations, including gas distribution, will be determined. As a result, there would be a unified GRC revenue requirements phase (Phase 1), just as is now the case for California's other major electric and gas utility, SDG&E.

A unified GRC would be consistent with the Commission's evolving approach to risk assessment and prioritization. To ensure the most cost-effective spending of ratepayer money on safety programs, PG&E needs to present – and the Commission needs to assess <u>and adjust</u> – PG&E's prioritization of risks and risk mitigation programs across all of its operations. This important effort is frustrated by the current bifurcated arrangement. For example, a gas distribution program described in the GRC may rank relatively high in risk mitigation among gas distribution programs but may be much lower down the list and not cost-effective when considered among GT&S programs. However, under PG&E's proposal to split off GT&S from the rest of the GRC, the Commission would not be able to make these types of judgments.

In addition, only in a unified GRC would the Commission be able to consider, and make adjustments for, the combined affordability impacts of GRC proposals and GT&S proposals. At a time when PG&E is regularly proposing huge revenue requirement increases, the Commission cannot make a well-informed decision about how much to increase revenue requirements for electric and gas distribution services without knowing the revenue requirements that would be needed for gas transmission operations. As noted above, unaffordable utility services leading to disconnections create their own extremely serious health and safety impacts. The Commission needs to be able to ensure affordability in a holistic way.

Finally, PG&E's presentation in this case shows that there is considerable uncertainty about PG&E's forecast expenditures in the second and third years of PG&E's proposed rate case period. PG&E explains that forecasts of monitoring costs are "relatively straightforward," but that forecasts of the problems that will be turned up and the resulting investigation and mitigation efforts "are less straightforward since they require more assumptions than monitoring forecasts."[106] In addition to corrosion control (to which the above quote relates), this increased forecast uncertainty is likely to be an issue for, among other areas, mitigation efforts resulting

[106] PG&E Direct, p. 7-16.

from ILI assessments.[107] By limiting the rate case period to two years, the Commission can avoid speculative judgments about forecasts for 2017.

VIII. The Commission Should Reject PG&E's Proposal for a Two-Way Integrity Management Balancing Account

PG&E proposes a two-way balancing account for both expenses and capital expenditures for programs that it identifies as Integrity Management (IM) programs in Table 4A-2 of its testimony.[108] This would be a change from the current one-way TIMP balancing account that PG&E and other parties agreed to in the settlement adopted in D.11-04-031.

For the following reasons, TURN opposes the two-way proposal and recommends that the Commission retain the current one-way balancing account.[109]

First, PG&E's proposes a major expansion of the scope of the balancing account. By TURN's calculation, PG&E's 2015 expense estimates for the 12 expense categories it includes in Table 4A-2 total approximately $120 million. This does not count costs for "TIMP Pressure Tests," for which PG&E does not provide a separate cost forecast in Chapter 4A. For the two capital programs (Make Piggable programs) that PG&E wants to be covered by the balancing account, the forecast three-year expenditures are about $300 million. In contrast, the current balancing account adopted in D.11-04-031 applied only to expenses that PG&E forecast at $22 million for the test year.[110]

Second, PG&E's proposal would not encourage cost containment for this broad scope of costs. PG&E proposes that it be able to seek rate recovery for cost overruns via a Tier 3 advice letter. However, the advice letter process, even one that requires a Commission decision, does

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[107] PG&E Direct, p. 4A-14, re Direct Examination and Repair Digs, for which PG&E seeks special attrition (p. 4A-15)
[108] PG&E Direct, p. 4-17.
[109] In addition to the reasons discussed below, TURN notes that adopting the two-year cycle for this case proposed above would mitigate forecast uncertainty for PG&E.
[110] D.11-04-031, App. A, Section 7.3.1.

not afford an opportunity for the scrutiny of discovery and cross examination. As discussed above, even in this proceeding with evidentiary hearings, PG&E has provided poor support for its 2011-2014 capital costs above authorized levels. If PG&E knows that its cost overruns will be subject only to the minimal review afforded by the advice letter process, PG&E will have little, if any, incentive to control its costs. This would be a particular challenge with respect to the considerable work that PG&E is expecting to ask contractors to perform. PG&E will have little incentive to keep contractor costs down, something contractors will know and be able to capitalize upon, to the disadvantage of PG&E's ratepayers.

Third, there is every reason to believe that PG&E will face major cost containment challenges resulting from PG&E's continuing need to remediate deficiencies that should have been addressed long ago. As Mr. Berger points out, PG&E's proposal stretches, and perhaps exceeds, the company's (and its contractors') capacity to perform the work efficiently and at reasonable cost.[111] PG&E's two-way balancing account proposal would shift to ratepayers the risk of cost overruns resulting from the rushed nature of PG&E's work, rather than keeping this risk on the company's shareholders where it belongs.

Fourth, by including the costs of TIMP hydrotesting in the scope of the balancing account, PG&E creates opportunities for cost-accounting mischief at the expense of ratepayers that will be very difficult for the Commission to police. As noted, PG&E does not even provide a TIMP hydrotesting forecast in its testimony. In addition, if the Commission caps the costs of the PSEP-continuation of the hydrotesting program, as TURN recommends, PG&E would have an incentive to evade the cost caps by claiming that excess costs were the result of TIMP work and not the hydrotesting required by D.11-06-017. The Commission can and should prevent

[111] Berger Testimony, pp. 9-10.

these issues from arising by removing hydrotesting from the category of costs covered by the balancing account.

Appendix A

STATEMENT OF QUALIFICATIONS OF THOMAS J. LONG

Mr. Long is TURN's Legal Director. He has practiced before, or been employed by, the California Public Utilities Commission for over 25 years and, in that period, has been involved, as an advocate or Commissioner advisor, in numerous important CPUC proceedings in the energy and telecommunications sectors. Since rejoining TURN in September 2011, Mr. Long has served as TURN's lead attorney and director of policy in every major Commission proceeding relating to gas pipeline safety, including PG&E's PSEP proceeding (R.11-02-019), the Sempra Utilities PSEP proceeding (A.11-11-002), and the pending enforcement proceedings against PG&E relating to the San Bruno explosion and its causes (I.12-01-007), PG&E's recordkeeping problems (I.11-02-016), and alleged class location violations by PG&E (I.11-11-009). In addition, he has led TURN's efforts in the risk integration round (Round 1) of the Rate Case Plan rulemaking (R.13-11-006), including speaking on two panels in multi-day workshops relating to integrating risk assessment and mitigation models into the GRC process.

Other energy cases in which Mr. Long has participated include the Diablo Canyon prudence review, PG&E's Cornerstone application, the Commission's investigation into the 2003 PG&E Mission Substation fire, the Community Choice Aggregation ("CCA") rulemaking, PG&E's 2011 and 2014 general rate cases, the 2012 Sempra general rate case, and Southern California Edison's 2011 rate design proceeding.

Prior to re-joining TURN as its Legal Director in September 2011, he served as a Deputy City Attorney for the City and County of San Francisco ("CCSF") for over six years. There, among other duties, he represented CCSF in proceedings before the CPUC and advised the City's Public Utilities Commission on its efforts to implement a CCA program. From 2001 through 2004, he served as a policy and legal advisor to CPUC President/Commissioner Loretta Lynch. Before that, he was TURN's Senior Telecommunications Attorney from 1990 through

2000. Mr. Long began his legal career as a Litigation Attorney for the law firm of Morrison & Foerster from 1986 to 1989, after serving as Law Clerk to United States District Court Judge Rudi M. Brewster.

Mr. Long earned his B.A. with High Honors in Economics and Political Science from Swarthmore College and his J.D. *cum laude* from New York University School of Law.