BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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

COMMENTS OF THE UTILITY REFORM NETWORK ON THE PROPOSED DECISION OF ADMINSTRATIVE LAW JUDGE BUSHEY

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I. INTRODUCTION AND SUMMARY

The Utility Reform Network ("TURN") submits these comments on the Proposed Decision of Administrative Law Judge Bushey ("PD") regarding the proposed Phase One Pipeline Safety Enhancement Plan ("PSEP") of Pacific Gas and Electric Company ("PG&E").

The PD correctly disallows from rate recovery significant costs in PG&E's proposed PSEP, but does not go far enough. As discussed below, as a result of both factual and legal errors, the PD errs by: (1) rubber-stamping the miles of pipeline testing and replacement proposed by PG&E; (2) failing to disallow all costs to replace pipeline segments installed after 1955; (3) allowing PG&E to reap a full rate of return on PSEP pipeline replacement for 60 years of the 65-year depreciable life of the pipelines; and (4) approving PG&E's valve program, which relies excessively on remote control valves that will not be activated in time to prevent future San Bruno-like disasters. In addition, TURN recommends various clarifications to the PD to promote the intent of the PD and to avert unnecessary controversy in the future.

In Appendix A, TURN recommends revisions to the PD's Findings of Fact ("FOF"), Conclusions of Law ("COL") and Ordering Paragraphs ("OP") that correct the PD's errors and make necessary clarifications.

II. THE PD ERRS IN RUBBER-STAMPING THE MILES OF PIPELINE TESTING AND REPLACEMENT PROPOSED IN THE PSEP

The PD accepts without modification PG&E's admittedly imprecise estimates that, in Phase 1, the company will replace 186 miles and hydrotest 783 miles of pipeline.[1] These testing and replacement miles serve to determine the outer limit of costs – minus mandated

[1] PD, p. 3.

disallowances – that PG&E will be permitted to recover from ratepayers. The record shows that these estimates are erroneously high, and the PD's acceptance of these estimates is clear error that, if uncorrected, will require ratepayers to pay for unnecessary work and allow PG&E to circumvent the PD's cost caps. While the PD's one-way balancing account and reporting requirements are a necessary step to ensure ratepayers only pay actual costs, those ratemaking mechanisms are insufficient to ensure that costs are expended only on PSEP-eligible projects and that PG&E bears the risk of overruns beyond the generous unit costs for testing and replacement allowed by the PD.

A. The Approved Scope of Pipeline Testing and Replacement Projects Should Be Reduced Based on the Results of the MAOP Validation Project

PG&E acknowledged that its PSEP estimates were based on a snapshot from its Geographic Information System ("GIS") database as of January 2011, long before it had concluded its MAOP validation work for high consequence area ("HCA") pipe segments.[2] It is undisputed that, since January 2011, PG&E had located complete pressure test records that would obviate the need to test or replace at least 157 miles of pipeline in its PSEP,[3] more than 15 percent of the total miles approved in the PD. After the close of the record, PG&E may have found more records that obviate the need for PSEP activity. <u>There is no good reason that any segments that do not require testing or replacement should be counted toward the cost recovery approved for PG&E</u>. TURN recognizes that some of these ineligible segments may already be excluded from cost recovery by virtue of the PD's disallowance of post-1955 hydrotesting costs. However, because the PD would allow recovery of most pipeline replacement costs, the

[2] PG&E Reply Brief, p. 64.
[3] TURN Opening Brief, p. 19. In its Reply Brief, PG&E did not challenge TURN's numbers.

inclusion of ineligible segments in the approved 186 replacement miles erroneously inflates the costs for replacing pipeline, which is by far the most costly PSEP program.

The PD's adoption of a one-way balancing account, although welcome, does not address this problem. In a perfect world, PG&E would not perform these ineligible projects and its expenditures would be commensurately reduced and returned to ratepayers. However, in the real world of complex project accounting, there is significant opportunity for cost overruns on eligible projects to erase refunds that would otherwise be due to ratepayers for ineligible projects that are not performed.[4] In addition, the PD's undefined loophole that allows reductions to the cost cap for uncompleted projects to be offset by "higher priority projects"[5] (discussed further below) offers additional opportunities that PG&E can exploit to defeat the intent of the one-way balancing account. At a minimum, policing the PSEP implementation to prevent such unintended outcomes would be extremely time-consuming and unnecessarily divert Commission resources from other safety work.

To remedy this error, the PD should be modified to require PG&E to update its mileage estimates in an advice letter filing shortly after the decision's issuance. In this way, the cost cap can be reduced to exclude costs for ineligible segments and prevent any opportunity for cost recovery for work that is not performed.[6] In Appendix A, TURN recommends an OP to accomplish this result.

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[4] For example, a PG&E "project" may include some eligible segments for which PG&E continues to lack records – and hence need to be addressed in the PSEP – and other ineligible segments that were originally included in the PSEP estimates, but for which PG&E has now located the requisite records. In this situation, even with the best (and highly time-consuming) monitoring efforts by CPSD, it would be extremely difficult, if not impossible, to ensure that PG&E does not take advantage of the inclusion of the ineligible segments in the cost cap as a means to recoup cost overruns for the eligible segments.
[5] PD, p. 112.
[6] As a ballpark estimate of the magnitude of this error, in light of the fact that, since the compilation of the database used to develop the PSEP, PG&E has found the requisite records for at least 15% of the total

B. The PD Errs By Failing to Require that Most Class 2 Miles Be Removed From the Approved Phase 1 PSEP

Based on Decision (D.) 11-06-017, the PD correctly adopts as a "general rule" that pipeline segments in Class 1 or Class 2 locations will not be included in Phase 1. As an exception to this general rule, for purposes of "efficiency" or "sound engineering", the PD allows PG&E to include in Phase 1 Class 1 or 2 segments that are adjacent to priority locations. The PD appropriately concludes: "Pipeline segments in Class 2 or Class 1 locations which are not high consequence areas, or adjacent to Class 3 or 4 locations or high consequence areas, must be deferred to Phase 2 of the Implementation Plan."[7]

The PD errs, however, by not removing the many miles of non-adjacent Class 2 segments from the approved scope of the PSEP. Even though DRA recommended that non-adjacent Class 2 segments be excluded from Phase 1, PG&E did not supply any information for the record quantifying the Class 2 segments that are adjacent to priority segments. Instead, PG&E contended that all Class 2 segments should be included, adjacent or not.[8] In TURN's opening brief, we pointed out this gap in the record and posited that 10% of the PSEP Class 2 segments are appropriate to include in Phase 1 for project efficiency purposes,[9] a number that PG&E did not contest in its reply brief.[10] Given that PG&E, the party with the burden of proof, did not put in evidence regarding the percent of Class 2 segments that are adjacent to priority segments and

approved PSEP miles, we can assume that 15% of the replacement miles are actually ineligible. This would reduce the approved $881 million in capital costs for replacement (see PD, Table E-3) by 15%, or $132 million.

[7] PD, p. 69 (emphasis added).

[8] Ex. 21 (PG&E Rebuttal Testimony), pp. 3-15 to 3-16 (Q&A 30).

[9] TURN Opening Brief, pp. 23-24.

[10] PG&E acknowledged in its reply brief (p. 54, emphasis added) the TURN and DRA proposals to "eliminate many Class 2 segments that are not adjacent to" priority segments and chose to oppose these proposals by arguing that all Class 2 segments (adjacent or not) should remain in Phase 1. PG&E did not challenge the contention that a high proportion of the included Class 2 segments were not adjacent to priority segments.

did not contest TURN's 10% figure, the only conclusion supported by the record is that only 10% of the Class 2 pipe segments satisfy the PD's adjacency requirement.

Correcting for the erroneous inclusion of 90% of Class 2 miles in the PSEP would substantially reduce the number of pipeline miles covered by the PSEP: 36 replacement miles[11] and 141 hydrotesting miles[12] would be removed, resulting in a total cost reduction of $233 million.[13] The PD should be revised to require PG&E to promptly submit an advice letter that removes the non-adjacent Class 2 miles from Phase 1.

The Commission would be wrong to expect the one-way balancing account to remedy this error, for the reasons given in the previous section. Furthermore, requiring the non-adjacent Class 2 miles to be removed at the outset will forestall considerable controversy that would likely result from an unfortunate ambiguity in the PD. Although the above-quoted language on page 69, as well as FOF 22, are clear in only allowing adjacent Class 2 segments to be included, COL 20 suggests that PG&E could justify inclusion of non-adjacent Class 2 segments "with economic or engineering supporting rationale."[14] Such vague language offers no objective standard by which Commission staff or parties can assess whether Class 2 segments are appropriately included in Phase 1 and will surely foster significant controversy. Therefore, COL 20 should be modified to conform to FOF 22 and the text on page 69.

In the end, the best way for the Commission to ensure that PG&E only recovers costs for work that is properly included in Phase 1 is to require PG&E to promptly remove non-adjacent Class 2 segments from the PSEP in an advice letter filing that specifically addresses this problem and that is subject to review and protest by the parties.

[11] 40 Class 2 miles in the PSEP x 0.9.
[12] 157 Class 2 miles x 0.9.
[13] TURN Opening Brief, p. 24.
[14] PD, p. 120.

C. The PD Errs By Allowing Pipeline Replacement to Serve as the Default Option in Box M2 of the Decision Tree

TURN and DRA challenged PG&E's decision tree outcome to replace all pipeline that reaches decision tree Box M2.[15] The 100 miles of pipeline scheduled for replacement under this box includes *all* pre-1970 pipeline that is neither DSAW nor seamless and operates in an HCA at a pressure greater than 30% of SMYS.[16] In response to TURN's challenge, the PD accepts without question PG&E's characterization that this pipe has "substandard welds," such that the "increased probability of a manufacturing defect in the now suspect welds, coupled with the potentially catastrophic failure mode, counsels us that, while expensive, PG&E has justified the cost of replacing these pipeline segments."[17]

The Proposed Decision errs in accepting PG&E's characterization of all pre-1970 non-DSAW or non-seamless pipe as requiring replacement due to "substandard" or "suspect" welds. This finding ignores overwhelming evidence, including PG&E's own consultant report and rebuttal testimony, demonstrating that PG&E's blanket inclusion of *all welds* aside from DSAW is overbroad.

The basis for PG&E's conclusions is contained in Attachments 3B and 3C of PG&E's direct testimony. PG&E stated the fundamental rational for the 1970 cutoff date: "The significance of 1970 is that year demarks the effective start of U.S. Department of Transportation minimum Federal pipeline safety standards under 49 CFR."[18] PG&E further explained that manufacturers ceased production of pipe with low frequency ERW and flash-welded seams by 1970, and that manufacturers ceased the production of butt-welded and furnace-welded pipe in

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[15] While the PD mentions TURN arguments concerning outcome M2, the DRA likewise recommended hydrotesting as the default for M2. *See* DRA Opening Brief, p. 56.
[16] See, for example, Exh. 1, p. 3B-8 (the manufacturing threats decision tree).
[17] PD, p. 75.
[18] Exh. 1, p. 3B-9.

the 1960's.[19] PG&E also discussed improvements in steel-making that occurred during the 1960's.[20]

However, as illustrated graphically in PG&E's table of "pipe making practices,"[21] the 1970 cut-off date is arbitrary. Aside from DSAW and seamless pipe, there are pipelines with at least three other seam types – continuous butt weld pipe, ERW high frequency and spiral weld – that were manufactured starting in about 1925, 1950 and 1960, but *continue to be manufactured today*. PG&E provided no data or analysis as to whether pipe with these welds is slated for replacement in decision tree M2; and if so, how it possibly justifies a 1970 cut-off date for these weld types. These are not at all "substandard welds" in the same way that ERW low frequency or flash welds might be considered substandard welds.

Indeed, the consultant evaluation of PG&E's program further explained that the significance of the 1970 date is simply that "pipelines under Federal jurisdiction installed after that date were required to undergo a hydrostatic pressure test before entering service."[22] The consultant agreed that 1970 marked the end of flash-welded seam and low-frequency ERW seam manufacturing, but the consultant also concluded that PG&E's inclusion of *all* seam types, including spiral welds and flash welded pipe, as 'problem' pipe is "conservative" and "unnecessary."[23] Thus, PG&E's own consultant viewed the M2 decision tree step as overly inclusive.

Lastly, in rebuttal testimony PG&E admitted that it will apply "practical engineering judgment … on a case-by-case basis" to determine whether for some of these pipelines "a

[19] Exh. 1, pp. 3B-10 to 3B-11.
[20] *Id.*
[21] See, Exh. 1, p. 3B-9.
[22] Exh. 1, p. 3C-11 to 3C-12.
[23] Exh. 1, p. 3C-12.

strength test would provide the same level of safety as replacement."[24] PG&E's witness Hogenson further explained on the stand that PG&E will evaluate for each replacement project "the particular pipeline, its location, its operating stress, its history, … the year it was manufactured, the type of long seam, its location on our system."[25] In other words, PG&E conceded that it is not reasonable to replace every non-DSAW pipe segment – including those with spiral welds or continuous butt welds -- just because it was manufactured prior to 1970.

The goal of D.11-06-017 was to implement Plans that would address important safety concerns in an "orderly and cost-conscious" manner.[26] The PD undermines this goal by allowing PG&E to spend capital on replacement projects that are not necessary at this time and that serve PG&E's interests in increasing rate base and solving other problems not related to weld types. To prevent this outcome, TURN recommended that PG&E be required to submit advice letters justifying replacement projects based on more detailed information, a recommendation that the PD erroneously and arbitrarily fails to address.

At a minimum, the PD should be revised to require PG&E to provide a sound engineering justification for each Box M2 replacement project, to obtain CPSD approval before proceeding with any such project, and to include such justifications and the status of CPSD's review in the quarterly compliance reports required by the PD.

III. THE PD'S FAILURE TO DISALLOW ALL COSTS OF REPLACING POST-1955 PIPE SEGMENTS CONSTITUTES LEGAL ERROR

The PD rejects TURN's recommendation to disallow all costs to replace post-1955 pipeline segments, instead disallowing only the imputed cost of hydrotesting such segments, a

[24] Exh. 21, A45, p. 3-22:3-8, Hogenson, PG&E.
[25] RT 1508-1509, Hogenson, PG&E.
[26] D.11-06-017, p. 18.

small fraction of the total replacement costs. The PD reasons that, while shareholders should be responsible for the costs of re-testing these segments, ratepayers should not receive a new pipeline at no cost.[27]

While the disallowance of imputed re-testing costs is certainly warranted, the law requires a full disallowance of these replacement costs. Public Utilities Code Section 463, which is misconstrued in the PD, and Commission precedent, which is not addressed in the PD, are clear that the Commission must disallow costs, such as these, that would not be incurred but for the violations and imprudence of the utility. PG&E has not demonstrated that, absent its inability to present the required pressure test records, it would be necessary to replace this post-1955 pipeline at this time.

The impact of this legal error is to require ratepayers to pay $241 million in capital costs that should be disallowed.[28]

A. The PD Fails to Recognize that Public Utilities Code Section 463 and Commission Precedent Require Shareholders, Not Ratepayers, to Bear the Consequences of Utility Violations and Imprudence

The PD overlooks, and therefore does not address, an important part of TURN's argument that compels the disallowance of post-1955 replacement costs. TURN's position has been – and continues to be -- that both Section 463 and Commission precedent do not permit ratepayers to be forced to pay for the consequences of a utility's violations and imprudence.[29] Section 463(a) is clear that the Commission "shall disallow" "direct or indirect" costs resulting from a utility's errors or omissions. And, in a variety of Commission decisions cited in TURN's

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[27] PD, p. 62.
[28] This calculation is based on the costs and mileage in Appendix A to TURN's Reply Brief. To calculate this number, TURN deducted the costs of hydrotesting the 53.6 miles of post-1955 segments ($27 million) from the total cost of replacing those segments ($241 million).
[29] TURN Opening Brief, pp. 62-63, 67-68; TURN Reply Brief, pp. 3-6.

briefs,[30] the Commission has held that it is neither just nor reasonable under Public Utilities Code Section 451 to saddle ratepayers with costs resulting from a utility's imprudence. As the Commission stated in D.84-09-120, "it would be unconscionable from a regulatory perspective to reward such imprudent activity by passing the resultant costs through to ratepayers."[31]

To the limited extent it addresses Section 463 at all, the PD fails to address TURN's key argument. The PD states that Section 463 does not require disallowance of costs on the basis that they should have made the expenditures at an earlier date.[32] To illustrate this point, the PD uses the example of the Commission's disallowance of costs stemming from the 1985 accident at the Mojave Power Plant. The PD explains that, if, hypothetically, the utility in that case had sought ratepayer funding to make needed safety improvements at a second plant, the reasonableness standard and Section 463 would not support a disallowance unless the utility had previously obtained ratepayer funding to make the improvements.[33] Thus, the PD's main focus is whether ratepayers have previously paid for work and are being asked to pay for it a second time.

While certainly it is neither just nor reasonable under Section 451 to require ratepayers to pay twice for the same work,[34] that is not the sole basis for disallowing costs under Sections 463 and 451. As noted, Section 463 and the cases interpreting Section 451 also require disallowance of costs that arise from a utility's imprudence. Using the hypothetical example in the PD, if the utility owning the Mojave Plant had built two power plants with unsafe conditions and one plant had an explosion resulting from the deficient safety conditions, the costs to remediate the unsafe conditions at the second plant could not be passed on to ratepayers under Sections 463 and 451.

[30] See TURN's Reply Brief, pp. 5-6, citing D.94-03-048 (Mojave Coal Plant accident); D.85-08-102 (failed pipeline in Helms pumped storage project); and D.84-09-120.
[31] D.84-09-120, 16 CPUC 2d 249, 283.
[32] PD, p. 55.
[33] PD, p. 55-56, fn. 44.
[34] TURN agrees with the PD that this is an appropriate basis for disallowing post-1955 hydrotesting costs.

The utility would have been imprudent in allowing unsafe conditions at either plant and because the costs to fix the second plant would result from that imprudence, Sections 463 and 451 do not allow ratepayers to be saddled with the resulting remedial costs.

By failing to recognize that Sections 463 and 451 do not allow utilities to impose on ratepayers the costs that arise from their imprudence, the PD commits legal error.

B. Because the Costs to Replace Post-1955 Pipelines Result from PG&E's Failure to Produce the Required Pressure Test Records, These Costs Must Be Disallowed in Full

The PD correctly finds that "if PG&E had competently retained the pressure test records for pipeline installed from 1956 to 1961, we would have evidence that such pressure tests did, in fact, occur and this pipeline would not be included in the Implementation Plan."[35] Moreover, there is no dispute that, from 1961 to 1970, GO 112 required PG&E to retain pressure test records for the life of the pipeline,[36] and that the federal regulations in effect from 1970 to the present also require retention of pressure test records for the life of the segment.[37] Thus, it is undisputed that any post-1955 pipeline segments would not be in the PSEP unless PG&E had imprudently failed to retain the pressure test records required by industry standards and applicable regulations. Under these circumstances, PSEP costs to test <u>or replace</u> the post-1955 segments are the consequence of PG&E's imprudence and violations and, under Sections 463 and 451, may not be imposed on ratepayers.

As noted, the PD nevertheless allows PG&E to recover most of the costs to replace post-1955 pipe segments based on the view that "ratepayers should not receive a new pipeline at no

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[35] PD, pp. 60-61.
[36] GO 112, adopted December 28, 1960, Section 841.417.
[37] 49 C.F.R. Section 192.517.

cost."[38] However, this conclusion ignores how these replacement costs came to be part of the PSEP. PG&E has not shown, and the PD does not find, that, in the absence of the D.11-06-017 requirement to document test pressures, it would be necessary to replace the post-1955 pipe in the PSEP. In fact, PG&E's decision trees (Boxes 1H, 2F, and 3A) show that, if PG&E could produce the requisite pressure test record, there would be no need to replace any pipe in the PSEP. As a result, the PD can only find that, given the lack of a pressure test record, PG&E's pipe replacement proposal is justified.[39] Absent D.11-06-017's requirement to produce pressure test records, it may be that, some years or decades from now, it would be prudent for PG&E to seek Commission authorization to replace some of the post-1955 segments in the PSEP based on the age and condition of the pipe. In that case, assuming PG&E convinced the Commission of the need, it would be entirely appropriate for ratepayers to pay the full costs of new pipeline. But, in this case, none of the post-1955 replacement costs would need to be incurred if PG&E had been competent enough – and sufficiently attentive to safety -- to retain the required pressure test records. The law is clear that ratepayers should not be forced to pay for the consequences of PG&E's incompetence.

C. Costs to Replace Post-1970 Pipe Segments Must Not Be Imposed on Ratepayers

The problems with the PD's determination to impose (most) post-1955 pipeline replacement costs on ratepayers are most pronounced with respect to post-1970 segments. PG&E's inability to produce pressure test records is particularly egregious for these segments, as federal regulations have been abundantly clear that pressure test records meeting the detailed

[38] PD, p. 62.
[39] In Section II.C above, TURN demonstrates that the PD errs in validating PG&E's decision tree Box M2 that requires replacement of all pipe segments operating at greater than or equal to 30% of SMYS.

requirements of Section 192.517 must be retained for the life of the pipeline. In addition, as noted in Section II.C above, PG&E does not even contend that post-1970 segments have suspect or substandard welds warranting replacement. Furthermore, even PG&E's testimony acknowledges that PG&E shareholders should pay the costs to replace post-1970 segments.[40]

As shown in the previous section, the law requires disallowance of all post-1955 replacement costs. However, if (contrary to the law), the Commission is not convinced that it should disallow all such costs, it must at least disallow the post-1970 replacement costs. In light of the undisputed facts recounted in the previous paragraph, imposing these costs on ratepayers would be grossly unfair. PG&E has not advanced any engineering reason why this relatively modern pipe needs to be replaced. The only reason it is being replaced is because PG&E failed to comply with federal regulations. Ratepayers should not be forced to pay for the consequences of PG&E's egregious violations.

The costs to replace the 8.6 miles of post-1970 segments in PG&E's PSEP add $39 million in capital costs to the PSEP.[41] The PD should be revised to remove these projects and their associated costs.

IV. THE PD ERRS IN LIMITING THE RATE OF RETURN REDUCTION TO ONLY FIVE YEARS OF THE 65-YEAR DEPRECIABLE LIFE OF THE NEW PIPELINE

While the PD's conclusion to limit PG&E's return on PSEP capital expenditures to PG&E's cost of debt is well-justified and a step in the right direction, it still requires ratepayers

[40] Ex. 2 (PG&E Opening Testimony), p. 3-66. However, in its Opening Brief, PG&E backed away from this position in a footnote that, for the first time, explained that PG&E was only proposing to forego recovery of post-1970 segment replacement costs during the 2011-2014 period, but would continue to seek recovery for the remainder of the pipe's 45-year (now 65 years under the PD) depreciable life. *See* TURN's Reply Brief, p. 17.
[41] TURN Reply Brief, Appendix A.

to pay PG&E a full return for 60 years of the 65-year depreciable life of the pipeline assets. Allowing nearly full profits on the PSEP cannot be justified in light of the PD's well-supported findings regarding PG&E's "poor management" of its gas transmission system[42] and the resulting urgent need to adopt safety improvements.[43]

Although the PD claims that the five-year limitation on the rate of return reduction will give PG&E an incentive to improve its management efforts,[44] the more likely result of sixty years of full profit on PSEP assets is that PG&E will have a strong incentive to expend as much capital as it can get away with under the rules adopted in this decision. The PD correctly states that "we must create powerful incentives for PG&E to manage this program efficiently and to aggressively identify and capture cost savings."[45] However, a nearly full return on PSEP assets, coupled with the errors discussed in Section II and III that improperly inflate the PSEP capital costs by hundreds of millions of dollars, would undermine the achievement of these admirable objectives. Instead, the PD would give PG&E the incentive and the opportunity to maximize capital expenditures and to allow capital cost overruns to negate PSEP cost savings from work that should be ineligible for rate recovery or that does not pass engineering muster.

V. THE PD ERRS IN RUBBER-STAMPING PG&E'S VALVE PROGRAM, WHICH RELIES EXCESSIVELY ON REMOTE CONTROL VALVES THAT PG&E HAS ADMITTED CANNOT BE ACTIVATED QUICKLY ENOUGH TO PREVENT DEATH AND SIGNIFICANT DESTRUCTION IN THE EVENT OF A RUPTURE

As the PD notes, PG&E proposed to automate most valves (except for those on earthquake faults) using remote control valves (RCVs), which require an operator to determine

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[42] PD, p. 108.
[43] PD, p. 102.
[44] PD, p. 108.
[45] PD, p. 101.

whether a rupture has occurred before initiating closure, rather than using automatic shut-off valves (ASVs), which close automatically based on pre-programmed logic controls in response to signals from monitoring points.

The PD fails to discuss the relative benefits of an ASV versus an RCV and simply accepts PG&E's conclusions:

> PG&E plans to operate most valves by remote control due to concern about a valve automatically but erroneously closing under non-rupture circumstances. PG&E presented detailed testimony on the system and customer impacts from unnecessary gas line closures.[46]
>
> ....
>
> We find that PG&E has provided detailed analysis of the basis for its proposed valve program and has justified the forecasted Phase 1 expenditures.[47]

These findings fly in the face of the evidence. The PD errs by accepting PG&E's plan without acknowledging the overwhelming evidence that RCVs will not accomplish safety goals, and that ASVs can be designed to eliminate or reduce the false closure problem. In particular, the PD disregards evidence from the NTSB Report that gas control operators are unlikely to be able to conclude that a rupture occurred within the ten-minute timeline that would be necessary in order to shut off gas flow within 30 minutes.[48] Furthermore, as discussed below, recent PG&E testimony in I.12-01-007 contradicts PG&E's claims in this case that RCVs can be counted upon to operate sufficiently rapidly to prevent death and significant destruction.

PG&E itself agreed that the safety goal is to cut off gas flow within thirty minutes. In this proceeding, Mr. Menegus, testified that PG&E "anticipates that RCVs … will typically allow for

[46] PD, p. 78.
[47] PD, p. 79.
[48] See, TURN Opening Brief, Sec. 4.2.3, p. 49-51.

a pipe segment to be isolated and blown down to near atmospheric pressure within 30 minutes."[49] However, in recent oral testimony in I.12-01-007 (the San Bruno Investigation), PG&E's own Manager in charge of gas control room operations, Mr. Slibsager, testified that it would take a gas control room operator "*as short as 25 or 30 minutes* and as, you know, *as long as maybe an hour and a half*" to initiate closure of an RCV, depending on the amount and quality of SCADA information they were receiving.[50]

Both Mr. Menegus and Mr. Slibsager have long experience at PG&E. However, Mr. Menegus's work has primarily involved design and engineering of pipeline assets, including transmission projects and control station engineering.[51] Mr. Slibsager, on the other hand, has direct knowledge of gas control room operations, including managing the gas control room operators.[52] The weight of the evidence – including the actual information from the NTSB San Bruno report, Mr. Menegus's very tentative conclusions regarding control room operator responses, and the detailed responses provided by Mr. Slibsager – all indicate that in an actual rupture situation, an RCV may provide little incremental safety benefit as compared to a manual valve.

Indeed, Mr. Slibsager reiterated that, based on the SCADA information available on September 9, 2010, the gas control room operators would have "taken … a considerable amount of time to make the decision to close that [RCV] valve," and he concluded, "I'm not so sure looking at what transpired on that day that they would have had enough knowledge to have

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[49] Exh. 2, p. 4-24:26-29, Menegus/PG&E.
[50] I.12-01-007/I.11-02-016, 2 RT 201:7-15, Slibsager/ PG&E (emphasis added). TURN is concurrently filing a Motion to Set Aside Submission and Reopen the Record To Take Additional Evidence seeking to admit this transcript into the record of R.11-02-019.
[51] Exh. 2, p. DKM-1.
[52] PG&E Testimony, I.12-01-007 (attached to TURN's accompanying motion as App. B), p. 14-8. Mr. Slibsager testified on a panel together with Mr. Kazimirsky, another PG&E veteran with engineering experience in gas operations, SCADA and control systems. PG&E Testimony, I.12-01-007, p. 14-4.

[activated the RCV] or how fast they would have been able to do that."[53] In contrast, Mr. Slibsager agreed that an ASV would have "closed as soon as it got the signal from the valve," and it would have cut off gas flow "providing the valve operated appropriately as it was designed to."[54]

The PD accepts PG&E's "detailed testimony" regarding unnecessary line closures.[55] However, the evidence in this proceeding shows that PG&E's false closure concern[56] is based on a false premise and can be readily addressed.

No one disputes that "unnecessary gas line closures" can have harmful impacts. However, PG&E's testimony concerning the likelihood of "false closures" was based on the assumption that an ASV would be triggered based on data from a single monitoring point at the location of the valve.[57] But in rebuttal testimony and oral cross-examination PG&E admitted that ASVs can be programmed: (1) to trigger based on multiple data inputs, essentially using the same data as would be used by a gas control operator, and (2) to allow for a manual override if necessary.[58] PG&E agreed that additional pressure monitoring signals and software would "allow ASVs to replace RCVs and accurately identify a pipeline rupture on pipelines in heavily populated areas with frequent gas delivery taps."[59] Furthermore, PG&E never rebutted the fact that false closures may be prevented by either manual overrides or by limiting automatic

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[53] I.12-01-007/I.11-02-016, 2 RT 205:26-206:6, Slibsager/ PG&E.
[54] I.12-01-007/I.11-02-016, 2 RT 201:20-27, Slibsager/ PG&E.
[55] PD, p. 78.
[56] In I.12-01-007, Mr. Kazimirsky reiterated these concerns, testifying that an ASV valve would not be placed on Line 132 due to the lack of "reliable technology" for an "exact means of detecting line rupture." I.12-01-007/I.11-02-016, 2 RT 207:16-25, Kazimirsky/ PG&E.
[57] See, 11 RT 1303-1304 and 1306-1308, Menegus, PG&E. Discussed in TURN's Opening Brief, Sec. 4.2.5, p. 53. Mr. Slibsager and Kazimirsky made the same assumption. I.12-01-007/I.11-02-016, 2 RT 206:20-26, Slibsager/PG&E.
[58] Exh. 21, p. 6-4:30-34, Menegus, PG&E; 11 RT 1311:7-12 and 1314:8-18, Menegus, PG&E.
[59] Exh. 21, p. 6-4:30-34, Menegus, PG&E.

functions during extremely high demand conditions.[60] The PD arbitrarily and erroneously ignores these admissions and unrebutted testimony.

The PD directs PG&E to "continue its review of new designs and operational options to allow for expanded use of automated valves," and to present an "updated showing of then-current best practices within the natural gas pipeline industry for automated shut-off valves" in its next rate case. The PD also directs PG&E "to improve its gas system control room operation due to the critical role it plays in addressing a rupture or functioning as the manual override on automatic valves."[61]

While these are nods in the right direction, they do not require any actions that will improve PG&E's current program of valve automation for HCA areas. <u>It makes little economic or safety sense to spend over $100 million now to install over 200 remote control valves that offer little, if any, benefit over manual valves</u>, particularly given the likelihood that ASVs are nearly ready for wide-scale deployment. Most or all of the investment in 200-plus RCVs would likely be wasted if they were required to be retrofitted or replaced in another two or three years.

TURN had recommended that PG&E install, on a pilot basis, at least 20% of its new automated valves (i.e. about 45 valves) as fully automatic shut-off valves, with complex logic controls that allow operation based on multiple signals. TURN continues to support that recommendation. In addition, in light of the new PG&E testimony admitting the response time limitations with RCVs, TURN would further recommend that the Commission slow down the installation of RCVs, and determine at a later time, based on additional operational information

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60 The "false closure" occurs when a large surge of gas demand – such as during a cold winter morning – results in a rapid pressure decline.

61 PD, pp. 79-80.

from the ASV pilot and other studies, whether it is safer and more cost effective to continue with ASVs.

VI. THE PD NEEDS CLARIFICATION REGARDING THE CORRECT FINDING THAT POST-1955 SEGMENTS WOULD NOT BE IN THE PSEP IF PG&E HAD RETAINED THE REQUIRED PRESSURE TEST RECORDS

The PD correctly finds that, if PG&E had retained pressure test records for post-1955 pipe segments, such segments would not need to be in the PSEP.[62] To support this finding, the PD correctly cites and affirms (in four different places) COL 3 of D.11-06-017, which stated that a pressure test record must include all elements required by regulations in effect when the test was conducted.[63]

TURN is concerned that the following vague and ambiguous sentence in footnote 48 of the PD may give rise to unnecessary controversy: "Notwithstanding compliance with historic standards, PG&E should evaluate these pipeline segments in later Phases of the Implementation Plan." The sentence is unclear as to what is meant by "evaluate." Given the PD's statement in four different places that a pressure test is valid if it meets the requirements in effect at the time of the pressure test, it seems clear that the sentence is not suggesting that these segments will need to be re-tested (or replaced) in a later PSEP phase. However, to avoid controversy on this issue, the sentence should either be deleted or made clear that the Commission is not intending to require re-testing of pre-1970 segments with a valid pressure test.

In the unlikely event that the PD intends to indicate a significant expansion of the scope of Phase 2, a single vague sentence in a footnote is the wrong way to do it. If the Commission is considering such an expansion, due process requires that the issues surrounding such an

[62] PD, pp. 60-61.
[63] PD, p. 61, fn. 48; p. 66; p. 115 (FOF 21); and p. 120 (COL 18).

expansion be fully vetted in a separate, duly noticed phase of this docket. In such a phase, which, like the phase leading to D.11-06-017, should apply to all California utilities, the Commission should take evidence regarding the benefits and costs of any such expansion of PSEP requirements and whether there are less costly ways to achieve the same safety objectives.

For related reasons, COL 19 in the PD also needs clarification. As it is now written, if COL 19 were standing alone, some parties might try to argue that a pressure test does not satisfy the Commission's PSEP requirements unless it meets post-1970 Subpart J pressure test requirements. Of course, this interpretation would blatantly conflict with the text on pages 61 and 66 and FOF 21 and COL 18 of the PD, as well as COL 3 and OP 3 of D.11-06-017. From the context of the PD, it is clear that the purpose of COL 19 is to summarize the PD's conclusion on page 67 rejecting TURN's recommendation to adopt a 90% of SMYS standard for pressure tests. Similar to COL 19, page 67 states that Subpart J pressure testing protocols are reasonable to use in pressure tests. In Appendix A, TURN recommends clarifying language for COL 19 that should help to avert future controversy.

VII. THE PD CORRECTLY ADOPTS EXPENSE AND CAPITAL LIMITS, BUT ADJUSTMENTS ARE NEEDED TO PREVENT PG&E FROM DEFEATING THE INTENT OF THE COST CAP

The PD correctly rejects PG&E's unreasonable contingency proposal and its request to increase its PSEP budget by an advice letter filing. In light of the generous costs for testing and replacement that the PD would approve and the urgent and expedited nature of the PSEP safety improvements resulting from PG&E's mismanagement, the PD appropriately states an intent not to allow PG&E to shift the risk of cost overruns to ratepayers.[64] To further this intent, the PD

[64] PD, p. 102.

adopts capital and expense limits and, further, appropriately addresses NCIP's legitimate concern about PG&E shifting projects to Phase 2, by requiring that the costs of projects not completed be deducted from the cost cap of the one-way balancing account.[65]

As noted in Section II above, the PD potentially defeats these protections by allowing PG&E to substitute other "higher priority" projects for uncompleted projects.[66] Without specificity and limits on how "other higher priority projects" are determined and approved, PG&E could use this opportunity as a loophole to push off some of the Phase 1 work to Phase 2, thereby effectively breaching the Phase 1 cost cap.

To fix this problem, PG&E should only be allowed to substitute other higher priority projects for work set forth in Attachment E, only: (1) if CPSD approves the change in writing; and (2) PG&E seeks and obtains Tier 3 advice letter approval for the change. The advice letter must demonstrate that the request would not have the effect of shifting any Phase 1 work to Phase 2.

TURN is also concerned with the following sentence on page 86 of the PD: "We find that improvements, efficiencies, and adjustments to the Implementation Plan based on sound engineering data and that further [] the objectives of the Plan are within the scope of the Plan and do not require further Commission review." Read in isolation, the sentence could be read to suggest that PG&E has carte blanche to make any PSEP changes it feels are warranted. However, this sentence appears just before the "CPSD Oversight" section, in which the Commission makes clear that, at a minimum, PG&E must obtain CPSD's concurrence for any changes to the Plan. To avoid any confusion or controversy, the phrase "subject to the

[65] PD, pp. 111-112.
[66] PD, p. 112.

requirement to obtain CPSD approval as set forth below" should be added to the above-quoted sentence.

VIII. THE COMMISSION SHOULD DOUBLE-CHECK AND CORRECT ANY ERRORS IN THE CALCULATION OF DISALLOWANCE AMOUNTS

Some of the disallowances ordered in the PD require complex calculations and careful analyses of PG&E's workpapers and supporting documentation. To date, TURN's limited resources have not allowed it to review the workpapers and calculations on which the disallowances are based. However, TURN understands that DRA has reviewed at least some of the workpapers and calculations and found significant errors that understate the disallowances and therefore overstate PG&E's rate recovery. TURN urges the Commission to carefully consider DRA's recommended corrections and to double-check its disallowance calculations for accuracy and the reasonableness of any underlying assumptions.

IX. CONCLUSION

For the reasons set forth above, TURN urges the Commission to correct the legal and factual errors identified in these comments and to make the other changes to the PD recommended in the text and Appendix A.

Date: November 16, 2012

Respectfully submitted,

By: __________/s/______________

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APPENDIX A
TURN's Recommended Changes to the Findings of Fact, Conclusions of Law, and Ordering Paragraphs

Findings of Fact

1. On August 26, 2011, PG&E filed and served its Implementation Plan required by D.11-06-017.

2. PG&E's Implementation Plan is comprised of: (A) Pipeline Modernization Program that provides for testing or replacing pipelines, reducing their operating pressure, conducting in-line inspections as well as retrofitting to allow for in-line inspection, and adding automatic or remotely-controlled shut off-valves; and (B) Pipeline Records Integration Program where PG&E will finish its records review and establish complete pipeline features data for the gas transmission pipelines and pipeline system components, and the Gas Transmission Asset Management Project, a substantially enhanced and improved electronic records system.

3. PG&E's Implementation Plan uses a consistent methodology to identify and prioritize recommended actions based on pipeline threat categories and PG&E organized this methodology into a decision tree to identify actions such as performing pressure tests, replacement of pipe, and in-line inspection, to address specific risks.

4. Natural gas pipelines carry explosive and flammable gas under pressure and are typically located in public rights-of-way, at times amidst dense populations. These facilities must be carefully operated and regulated to protect public safety.

5. The Independent Review Panel found numerous deficiencies in PG&E's operations, including data management and pipeline Integrity Management, and recommended improvements that included modifying its corporate culture and

engaging in a progression of activities to address pipeline safety using the image of a journey to a new destination.

6. PG&E's Decision Tree analysis is a promising beginning at a comprehensive decision-making process based on safety concerns related to historical pipeline manufacturing, fabrication, and testing practices.

7. PG&E must improve the safety of its gas system operations, specifically but not only in the areas quality control and field oversight.

8. The Implementation Plan calls for pressure testing 783 miles of pipeline and replacing 185.5 miles of pipeline in Phase 1.

9. PG&E's Decision Tree identifies and prioritizes three unique threats to pipeline integrity – manufacturing threats, fabrication and construction threats, and corrosion and latent mechanical damage threats.

10. The Implementation Plan calls for replacing, automating and upgrading 228 gas shut-off valves.

11. The Implementation Plan calls for retrofitting 199 miles of pipeline for in-line inspection and inspecting 234 miles of pipeline with in-line inspection tools.

12. The Implementation Plan calls for pressure reductions and increased leak inspections and patrols.

13. In D.11-06-017, the Commission required PG&E to include in its Implementation Plan a proposed cost allocation between shareholders and ratepayers, and PG&E's Implementation Plan included a discussion of costs to be absorbed by PG&E's shareholders.

14. PG&E's proposed cost allocation between shareholders and ratepayers reflects existing ratemaking policies and includes no material voluntary cost allocation to shareholders.

15. Generally, post-test year ratemaking is disfavored when a forecasted test year revenue requirement is used to set rates.

16. Adopted in 1955, the American Standard Association Code for Pressure Pipeline (ASA B31.8) required pre-service pressure testing for natural gas pipelines.

17. PG&E admits that it voluntarily complied with American Standard Association Code for Pressure Pipeline (ASA B31.8), beginning in 1955.

18. Since no later than January 1, 1956, PG&E complied with or stated that it complied with industry standards to pressure test pipeline prior to placing it in service. PG&E is unable to produce the records for certain pressure tests that would have been performed in accord with industry standards from January 1, 1956, or for pipeline of unknown installation date. The lack of pressure test records for pipeline placed into service after January 1, 1956, or with an unknown installation date, reflect an error in PG&E's operation of its natural gas system. No evidence was presented that PG&E excluded the costs of pressure testing pipeline from its regulated revenue requirement from January 1, 1956.

19. PG&E's cost forecast for pressure testing pipeline is materially higher than DRA's estimated costs, which include an allowance for contingency, but is based on actual PG&E pressure test costs and is therefore reasonable.

20. Requiring pressure tests of existing pipeline to attain pressures of 90% SMYS for each pipeline component is impractical, and the margin of safety attained in the 49 CFR subpart J pressure test specifications is calculated based on the maximum allowable operating pressure for the pipeline.

21. A valid pressure test record need only comply with the regulations in effect at the time the test was performed, not later adopted regulations.

22. Cost and engineering efficiency may be achieved by pressure testing pipeline segments adjacent to high priority segments.

23. PG&E's cost forecast for replacing pipeline is higher than DRA's estimated costs, which include an allowance for contingency, but is supported by actual PG&E operational experience and is therefore reasonable.

24. PG&E's cost forecast for replacing pipeline considered specific locations, as is illustrated by the Peninsula Adder for higher forecasted costs on the San Francisco peninsula.

25. PG&E has not demonstrated that pipeline segments that end up in the M2 box of the Decision tree have substandard welds and ~~will be operated a high pressure~~ necessarily require replacement.

26. In-line inspection is a useful means to obtain data on pipeline conditions including indentations, wall loss, pipe strain, metallurgical variations, and certain types of cracks.

27. PG&E's in-line inspection proposal expands its existing in-line inspection program, focuses on segments operating at high pressure, and is consistent with D.11-06-017.

28. PG&E's valve automation proposal will automate and upgrade 228 valves.

29. ~~Transmission main pipeline installed pursuant the Implementation Plan will be manufactured to higher standards than pipe installed 40 or more years ago and will be pressure tested prior to being placed in service~~ With respect to pipeline segments installed after 1955 or for which PG&E's records do not show an installation date, PG&E would have no need to test or replace such segments in the PSEP if PG&E had retained the pressure test records required by industry standards and applicable regulations.

30. The Commission has not authorized a memorandum account into which PG&E may record its Implementation Plan~~s~~ costs incurred prior to the effective date of today's decision.

31. The record shows that PG&E retained amounts in excess of its authorized rate of return during years when it did not spend its full authorized budget for gas pipeline improvements.

32. Improvements, efficiencies, and adjustments based on sound engineering practice to the Implementation Plan in furtherance of the objectives of the Plan and approved by CPSD are within the scope of the Plan and do not require further ~~Commission~~ review by the full Commission, except as otherwise required by this decision.

33. From the date installed, PG&E was responsible for creating and maintaining accurate and accessible records of its natural gas system equipment and facilities.

34. PG&E's failure to possess accurate and accessible records of its gas system caused the NTSB and this Commission to direct PG&E to correct these deficiencies.

35. PG&E's historic gas system revenue requirement has included costs for maintaining gas system records.

36. PG&E's imprudent management decisions to delay pipeline pressure testing and replacement contributed to the need for and timing of the projects needed pursuant to the Implementation Plan, which led to increased risk of cost overruns on projects.

37. An escalation rate tied to the overall inflation rate, as proposed by DRA, is a reasonable escalation factor for Implementation Plan projects.

38. The scope of and timing for the extraordinary capital investment needs of the Implementation Plan were caused, in part, by PG&E's imprudent management decisions regarding pipeline records and pressure testing older pipeline.

39. PG&E has been inefficient and ineffective in its management of it natural gas system.

40. The amounts in Attachment E are program-based upper limits on expense and capital costs to be recovered from ratepayers for the specific projects authorized through the Implementation Plan. To the extent specific authorized Phase 1 projects are not completed by the end of 2014 and not replaced with other higher priority projects <u>that are approved as required by this decision</u>, the expense and capital cost limit of the balancing account is reduced by the amounts associated with the project not completed.

41. <u>PG&E's Plan, as proposed, includes segments for which PG&E has now located pressure test records that meet the requirements of D.11-06-017.</u>

42. <u>The record shows that 90 percent of the Class 2 segment miles included in PG&E's Plan are not adjacent to segments in high consequence areas (HCA) or Class 3 or Class 4 locations</u>.

43. <u>The record shows that remote control valves provide little, if any, benefit over manual valves in terms of allowing activation sufficiently rapidly to prevent catastrophic death or destruction after a serious pipeline rupture</u>.

Conclusions of Law

1. In D.11-06-017, the Commission declared an end to historic exemptions from pressure testing for natural gas pipeline and ordered all California natural gas system operators to file Natural Gas Transmission Pipeline Testing Implementation Plans.

2. As required by § 451 all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified," as provided in § 454.

3. The burden of proof is on PG&E to demonstrate that it is entitled to the relief sought in this proceeding, including affirmatively establishing the reasonableness of all aspects of the application.

4. The standard of proof that PG&E must meet is that of a preponderance of evidence, which means such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.

5. The evidentiary record does not support DRA's request for a comprehensive disallowance of all Implementation Plan costs, and we deny the request.

6. The scope and magnitude of the costs at issue in the Implementation Plan justify deviation from the general rule against post-test year ratemaking

7. The public utility code standards for rate recovery, i.e., just and reasonable, and the disallowance concept reflected in § 463 ~~do not combine to~~ both provide an analytical basis for disallowing ~~reasonable~~ all costs ~~on the basis that the utility should have made the expenditures at an earlier date~~ that result from a utility's imprudence or violations.

8. Although TURN's proposal to disallow all Implementation Plan costs should be denied, TURN's proposal to disallow pipeline testing and replacement costs that result from PG&E's imprudence or violations is justified and should be approved.

9. With the following changes, PG&E's decision tree for ~~the~~ evaluating manufacturing threats, fabrication and construction threats, and corrosion and

latent mechanical damage threats should be approved: (a) in Boxes 1K, 1L, 2G, and 3B, PG&E should only include Class 2 segments that are adjacent to HCA or Class 3 or 4 segments; and (b) Box M2 should be revised to require pressure testing unless there is a sound engineering justification for replacement.

10. PG&E's proposal to retrofit 199 miles of pipeline for in-line inspection and inspect 234 miles of pipeline with in-line inspection tools should be approved.

11. PG&E's proposal for pressure reductions and increased leak inspections and patrols should be approved.

12. Because of its excessive reliance on remote control valves that require activation by a control room operator, PG&E's proposal to replace, automate and upgrade 228 gas shut-off valves in Phase 1 of the Implementation Plan should be ~~approved, and PG&E should continue to monitor industry experience with automated shut-off valves for possible revisions to its plans~~ denied at this time; instead, PG&E should proceed with a pilot program to replace 20% of its manual valves with automatic shut-off valves (ASVs) and then revise its plans after assessing its experience and industry experience with ASVs.

13. It is reasonable for PG&E's shareholders to absorb the portion of the Implementation Plan costs which were caused by imprudent management.

14. Because PG&E's proposed cost allocation between shareholders and ratepayers reflects existing ratemaking policies and includes no material voluntary cost allocation to shareholders, notwithstanding the Commission's directive to do so, and due to the scope and consequence of PG&E's imprudent management actions, it is reasonable to use exceptional ratemaking measures when considering shareholders' return on equity.

15. It is reasonable for shareholders to absorb the costs of pressure testing and replacing pipeline placed into service after January 1, 1956, or for which PG&E

has no known installation date, and for which PG&E is unable to produce pressure test records.

16. [**include only if the previous COL is not modified as proposed**] It is reasonable to impose an equitable adjustment to the replacement cost of pipeline installed from January 1, 1956, to ~~July 1, 1961~~ <u>the present</u>, for which pressure test records are not available, but which require replacement rather than pressure testing. Such an equitable adjustment shall be equal to the forecasted cost of pressure testing the pipeline and shall reduce the cost of the pipeline replacement included in rate base and revenue requirement.

17. PG&E's cost forecast for pressure testing pipeline is much higher than any other forecast in the record but is reasonable <u>in light of its implicit inclusion of a component for contingency</u>.

18. A valid record of a pipeline pressure test must include all elements required by regulations in effect at the time the test was conducted.

19. It is reasonable to require pressure tests of existing pipeline to comply with 49 CFR subpart J pressure test specifications <u>and not require testing to 90% of SMYS in all instances</u>.

20. PG&E has justified including pipeline segments located in Class 1 or 2 locations without high consequence areas but adjacent to Class 3 or 4 locations, ~~or with economic or engineering supporting rationale,~~ within Phase 1.

21. PG&E's cost forecast for replacing pipeline is substantially higher than DRA's <u>in part because it includes an implicit contingency component</u>, but is supported by significant operational experience and is therefore reasonable.

22. The request by TURN and the City and County of San Francisco to disallow pipeline replacement costs for alleged Integrity Management failures

should be ~~denied~~ deferred pending the completion of the records in Investigation (I.)11-02-016, I.11-11-009, and I.12-01-007.

23. PG&E's proposal to replace, rather than pressure test, all non-DSAW, seamed pipeline installed prior to 1970, ~~with weld that do not meet current standards,~~ operated at over 30% SMYS and located in high population areas is ~~reasonable~~ overinclusive; replacement of such pipeline must be justified by a sound engineering justification that is approved by CPSD and promptly shared with the parties.

24. PG&E's proposal to capitalize replacement pipe less than 50 feet in length is not reasonable and is denied. Such pipe must be expensed, consistent with current accounting practice.

25. It is reasonable to conclude that pipe installed pursuant to the Implementation Plan will have a longer service life than pipe installed over 40 years ago.

26. TURN's proposal to adopt a 65-year service life for transmission main pipe installed pursuant to the Implementation Plan is reasonable, and should be adopted.

27. PG&E has not justified recovering from ratepayers its Implementation Plan costs incurred prior to the effective date of today's decision.

28. Absent extraordinary circumstances, the rule against retroactive ratemaking prevents ratepayer representatives from recovering for ratepayers amounts authorized but unspent by PG&E for gas pipeline improvements.

29. PG&E's request for authority to file Tier 3 Advice Letters to modify the Implementation Plan should be denied.

30. Authority should be delegated to the Director of CPSD, or designee, (CPSD) to oversee all PG&E's work performed pursuant to the Implementation Plan, including:

A. CPSD shall review all changes to the Implementation Plan proposed by PG&E, shall require such modifications as are necessary to ensure public safety, and may concur in or reject ~~such proposals~~ changes proposed by PG&E, provided that CPSD approvals, rejections or modifications shall be in writing and promptly served on the parties.

B. CPSD may inspect, inquire, review, examine and participate in all activities of any kind related to the Implementation Plan. PG&E and its contractors shall immediately produce any document, analysis, test result, plan, of any kind related to the Implementation Plan as requested by CPSD, and such request need not be in writing.

C. CPSD may take and order PG&E to take such actions as may be necessary to protect immediate public safety.

D. CPSD may issue immediate stop work orders to PG&E and all its contractors when necessary to protect public safety, and PG&E must comply immediately and consistent with any needed safety protocols.

E. The Director of CPSD, the Commission's Executive Director, and the Chief Administrative Law Judge shall offer PG&E, parties to this proceeding, and the public such procedural opportunities as may be feasible under the specific circumstances of any instance in which CPSD is required to exercise its delegated authority.

31. The Executive Director should be delegated authority to order PG&E to reimburse the Commission for any Commission contract necessary to carry out the directives in today's decision, not to exceed $15,000,000 and PG&E should be authorized to record any amounts so expended in its Annual Gas True-Up Balancing Account for recovery from ratepayers.

32. PG&E should file compliance reports as specified in Attachment D. <u>The reports should also include a listing of all projects for which PG&E has presented to CPSD the sound engineering justification required by this decision before pipeline replacement pursuant to Decision Tree Box M2 may be undertaken, the justifications provided to CPSD, and the status of CPSD's review of such projects.</u>

33. It is not reasonable to adopt a cost overrun contingency allowance because PG&E's imprudent management decisions contributed to risk of such overruns and we adopt cost forecasts at the high end of the range of reasonableness with an added layer for program administration.

34. The Commission should impose strong incentives on PG&E to encourage efficient construction management and administration of the Implementation Plan.

35. PG&E's proposal for a 21% contingency adder should be denied.

36. A rate of 1.5% should be adopted to escalate costs from the effective date of today's decision to the date of project completion.

37. Due to inefficient and ineffective management decisions, PG&E's return on equity for investments made pursuant to the Implementation Plan should be reduced to the <u>then-applicable</u> incremental cost of debt <u>for the life of the investments</u>.

38. A one-way balancing account should be approved for all Implementation Plan projects, subject to the following limitation: To the extent PG&E incurs costs beyond the amounts set forth in Attachment E for projects approved in today's decision, the expense and capital overruns should not be recorded in the balancing account and capital cost overruns may not be recorded in regulated plant in service accounts. Similarly, where specific authorized Phase 1 projects are not completed by the end of 2014 and not replaced with other higher priority

projects that are approved as required by this decision, the expense and capital cost limit of the balancing account should be reduced by the amounts associated with the project not completed.

39. Pipeline segments that were included in PG&E's Plan but for which PG&E has now located pressure test records that meet the requirements of D.11-06-017 should be excluded from the Plan.

40. Class 2 pipeline segments that are not adjacent to segments in high consequence areas (HCA) or Class 3 or Class 4 locations should be excluded from the Plan.

O R D E R

IT IS ORDERED that:

1. The Pipeline Safety Enhancement Plan (Implementation Plan) of Pacific Gas and Electric Company (PG&E) is approved with the modifications required by this decision. PG&E must expeditiously and efficiently pursue the natural gas system safety improvements as described in the Implementation Plan.

2. [**These numbers should be corrected based on the changes made to the PD.**] Pacific Gas and Electric Company is authorized to increase its natural gas system regulated revenue requirement to be recovered from ratepayers from the amounts authorized in Decision 11-04-031 by the amounts set forth below in the year indicated:

	2012	2013	2014	TOTAL
$ 100's million	$14,019	$103,801	$159,984	$277,805

3. All increases in revenue requirement authorized in Ordering Paragraph 2 are subject to refund pending further Commission decisions in Investigation (I.) 11-02-016, I.11-11-009, and I.12-01-007.

4. Pacific Gas and Electric Company is authorized to submit a Tier 1 Advice Letter to revise its Preliminary Statement, Part B, to reflect a new rate component titled the "Implementation Plan Rate" in the customer class charge included in transportation charges to collect the annual increase in revenue requirement adopted in Ordering Paragraph 2, as shown in Attachment F to today's decision.

5. Pacific Gas and Electric Company (PG&E) is authorized to file a Tier 1 Advice Letter to create a one-way (downward) Gas Pipeline Expense and Capital Balancing Account to record the difference between forecast and recorded expenses and capital costs authorized for the Implementation Plan costs from the effective date of today's decision through December 31, 2014, for core and noncore customer classes. Any accumulated balance on December 31, 2014, plus interest, will be returned to customers through the Customer Class Charge in PG&E's Annual Gas True-Up Filing to be filed shortly before the end of 2014. Any accumulated balance will be allocated 59.5% to the core class and 40.5% to the noncore class.

6. Pacific Gas and Electric Company (PG&E) must limit the amounts recorded in the balancing account authorized in Ordering Paragraph 5 to the adopted expense and capital amounts set forth in Attachment E for each program. Expense and capital amounts in excess of adopted amounts may not be recorded in the balancing account and capital cost overruns may not be recorded in regulated plant in service accounts. The adopted expense and capital amounts for any program shall be reduced by the cost of any Implementation Plan project not completed and not replaced with a higher priority project that is

approved in accordance with paragraph 11 below. Subject to these limits, PG&E is authorized to collect from ratepayers only the revenue requirements associated with actual expenses and capital costs recorded in the balancing account.

7. Pacific Gas and Electric Company is authorized to file a Tier 1 Advice Letter to create a balancing account to record the amount of revenues collected from ratepayers through the Implementation Plan Rate as compared to the adopted revenue requirement. The balance, if any, as of December 31, 2014, shall be collected from or refunded to ratepayers through the next Annual Gas True-Up filing. Any accumulated balance will be allocated 59.5% to the core class and 40.5% to the noncore class.

8. The Director of the Commission's Consumer Protection and Safety Division, or designee, (CPSD) is delegated the following authority:

A. CPSD shall review all changes to the Implementation Plan proposed by Pacific Gas and Electric Company (PG&E), shall require such modifications as are necessary to ensure public safety, and may concur in or reject ~~such proposals~~ changes proposed by PG&E, provided that CPSD approvals, rejections or modifications shall be in writing and promptly served on the parties.

B. CPSD may inspect, inquire, review, examine and participate in all activities of any kind related to the Implementation Plan. PG&E and its contractors shall immediately produce any document, analysis, test result, plan, of any kind related to the Implementation Plan as requested by CPSD, and such request need not be in writing.

C. CPSD may take and order PG&E to take such actions as may be necessary to protect immediate public safety.

D. CPSD may issue immediate stop work orders to PG&E and all its contractors when necessary to protect public safety, and PG&E must comply immediately and consistent with any needed safety protocols.

E. The Director of CPSD, the Commission's Executive Director, and the Chief Administrative Law Judge shall offer PG&E, parties to this proceeding, and the public such procedural opportunities as may be feasible under the specific circumstances of any instance in which CPSD is required to exercise its delegated authority.

9. The Executive Director is delegated authority to order Pacific Gas and Electric Company (PG&E) to reimburse the Commission for any Commission contract necessary to carry out the directives in today's decision, not to exceed $15,000,000. PG&E is authorized to record any amounts so expended in its Annual Gas True-Up Balancing Account for recovery from ratepayers.

10. Pacific Gas and Electric Company must submit compliance reports on the schedule and including the information set forth in Attachment D to today's decision. Such reports shall be filed and served in this proceeding, with printed copies to the Directors of the Energy Division and the Consumer Protection and Safety Division.

11. PG&E may not replace a project approved by this decision until: (1) PG&E has demonstrated and CPSD has concurred, in writing, that the replacement project is a higher priority project for meeting the goals of D.11-06-017 and this decision; and (2) the Commission has concluded, based on a Tier 3 advice letter submitted by PG&E, that the replacement project is a higher priority project for meeting the goals of D.11-06-017 and this decision and that the replacement project would not have the effect of shifting to Phase 2 any Phase 1 work approved by this decision.

12. Within 30 days of the effective date of this decision, PG&E shall submit a Tier 3 advice letter that does the following: (a) removes from the Implementation Plan all segments for which PG&E has located pressure test records that meet the requirements of D.11-06-017; (b) removes from the Implementation Plan all Class 1 or 2 segments that are not adjacent to segments in high consequence areas or in Class 3 or 4; and (c) revises PG&E's valve automation plan in accordance with this decision. The advice letter shall present calculations, supported by complete workpapers, that reduce the revenue requirements and expense and capital limits in this decision to reflect these changes.